

Harmony Enterprise™ 2022.2 Help – PDF

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Table of Contents

About Harmony Enterprise™ 2022.2	8
Overview	10
Full version	10
SE license	10
Release notes	12
Active directory	26
Important considerations	26
User permissions in local folders	27
Database management	28
Create a database	28
Enable role-based security (RBS)	29
Adding groups or users to your database	29
Configuring well security	31
Upgrade an existing database	33
Defragment a database	33
Release orphaned wells	34
Troubleshooting	35
Harmony Enterprise in the cloud	37
Disclaimers	37
Assumptions	37
Limitations	38
Considerations for Management and IT	38
Terminology	39
Recommended specifications	40
Connection requirements	41
Microsoft Azure	42

Amazon web services (AWS)	53
General considerations	61
Licensing	62
Activating / deactivating licenses	62
Licensing dialog box	65
License Information dialog box	67
Licensing Settings dialog box	68
IHS Markit Online Activation dialog box	70
How to...	72
Connect to your data source	72
Get well data into Harmony Enterprise	78
Preview well data	92
Analyze well data	94
View results	96
Export data	98
Use workflows	107
Link / unlink analyses	112
Analysis types	118
Advanced Forecast	119
Analytical model	127
Custom forecast	148
Decline analysis	150
Duong decline analysis	160
Flowing Gradient	164
FMB analysis	169
Forecast consolidation	184
Gas IPR / TPC	185
Material Balance analysis	199

Multi-segment decline analysis	207
Multi-well model	211
Numerical model	268
Numerical URM	299
Oil cut analysis	312
Oil IPR / TPC	314
Probabilistic decline analysis (beta)	326
Ratio forecast	327
Ratio trend	328
Stretched exponential decline analysis	335
Surveillance analysis	339
Typecurve analysis	345
Unconventional reservoir analysis	367
Volumetrics analysis	382
WOR analysis	383
WOR / oil cut forecast	386
Navigation	389
Clipboard	389
Menus	391
Panels	394
Selecting entities	398
Status Window	401
Tabs	403
Toolbars	403
Components	410
Analysis Manager	410
Analysis tab	414
Analytics Explorer	415

Attributes tab	415
Best-fitting functionality	428
Bulk Editor dialog box	436
Database connection	438
Diagnostics tab	446
Economics	449
Editors	455
Entity Viewer - Custom	505
Entity Viewer - Hierarchy	508
GIS	512
Import functionality	534
Monitor tab	553
Options dialog box	558
Piper export	576
Plots	579
Plot Selection pane	589
Project filters	589
Query Wells dialog box	592
Reference Dates dialog box	595
Results tab	597
Role-based security	610
Scenarios	613
Spatial Explorer	614
Tables / grids	614
Well layers	617
Worksheets	617
Reference materials	631
Analysis theory	631

Calculations & correlations	889
General concepts	975
Nomenclature	1160
References	1183
Contact us	1195
Training	1196
Resources	1196
Customized training	1196
Index	1197

About Harmony Enterprise™ 2022.2

These topics highlight key content in Harmony Enterprise™ to get you started:

About Harmony

- [Overview](#)
- [Active directory](#)
- [Licensing](#)
- [Navigation](#)
- [Components / modules](#)
- [User permissions in local folders](#)

For hands-on practice with Harmony Enterprise, browse to the Examples folder. The default directory is C:\Users\Public\Public Documents\Harmony Shared\Harmony Enterprise 2022.2.

How to...

- [Connect to your data source](#)
- [Get well data into Harmony Enterprise](#)
- [Preview well data](#)
- [Analyze wells](#)
- [View results](#)
- [Export data](#)
- [Use workflows](#)

Reference Material

- [Analysis method theory](#)
- [Calculations & correlations](#)
- [General concepts](#)
- [Nomenclature](#)

Note: Prior to using Harmony Enterprise, you must follow the instructions in your EMS - Entitlement Certificate email. For more information, see the [License Manager help](#) and [installation guide](#).

Overview

Harmony Enterprise is a comprehensive engineering application for analyzing oil and gas well performance and evaluating reserves. For more information, see the [Harmony Enterprise web page](#).

After installing Harmony Enterprise™ and launching the application, the [License Type dialog box](#) opens. In this dialog box, you select between two versions: multi-user capable and single-user capable. (This dialog box only opens the first time you select your license type.)

Full version

The multi-user version is classified as the full version. You can have up to 100,000 wells in each project. All analysis work is centralized for better access, and multiple engineers can share one common project. In addition, you can import data once, which reduces the risk of duplicating wells and analyses.

The full version of Harmony Enterprise can be deployed either locally (on-premises) or in a cloud environment.

Regardless of the license type you are using, there are some limitations when Harmony Enterprise is running on the cloud (Azure or AWS). You are not able to:

- use standalone licenses.
- check out commuters.
- open nor create .hldb files on AWS. (You can open and create .hldb file on Azure.)
- import nor export .hldb files when running Harmony Enterprise on AppStream.

SE license

The SE license is the single-user version of Harmony Enterprise, and has some restrictions.

The SE license can be used when running Harmony Enterprise either locally (on-premises) or on Azure. It cannot be used on AWS.

You can manage up to 5000 wells with a local database (.hldb) file. However, you cannot:

- import or merge .hldb files
- connect to a multi-user database (a full SQL database)

- perform scheduled imports
- have role-based security

If you try to import a file that has more than 5000 wells, or where the incoming plus existing well count exceeds 5000, wells are imported up to the limit, and then a warning message is displayed in the Status Window.

Release notes

These release notes cover Harmony Enterprise versions 2022.2 – 2021.2. For prior release information, contact our Customer Care team: www.ihsmarket.com/supportform

Harmony Enterprise 2022.2 Release Notes

Final release to support Windows 8.1

This is the last release that supports Windows 8.1. Subsequent releases will only support Windows 10 and 11.

Support limited to versions released in prior 18 months

Effective Nov. 1, 2022, support will be limited to versions of Harmony Enterprise released within the previous 18 months. The list of supported versions will be updated each release. The initial versions supported will include: 2021.2, 2021.3, 2022.1, and 2022.2.

Added support for hldb files and SE licenses on Azure

If Harmony Enterprise is deployed on Azure, you can create, open, extract, and import to .hldb files. This change also adds support for SE licenses (for example, Forecast SE).

Note: AWS AppStream does not support Microsoft LocalDB (the back-end for .hldb files). For this reason, .hldb files and SE license restrictions remain when deployed on AWS AppStream.

Artificial lift analysis: gas lift and ESP evaluation within Optimize

Gas lift

Evaluate gas lift systems in the Flowing Gradient and inflow performance relationship / tubing performance curve (IPR / TPC) worksheets. Optimize Configurations support multi-valve gas lift operations, with valve differential pressure considerations.

Sensitize your injection rate and pressure to see the response in operating point rate, as well as find your well's operating valve.

Electric submersible pumps (ESPs)

Optimize Configurations in the Wellbore editor now support more robust pressure calculations for ESPs. Pumps that have been configured are shared globally, and can be associated with any Optimize Configuration. These configurations are then supported in the Flowing Gradient and Oil IPR / TPC worksheets.

From the Flowing Gradient worksheet, calculate the flow conditions at any point along the wellbore by specifying an expected production rate and a flowing pressure (wellhead, pump intake, or sandface). You can vary the gas separation efficiency of the pump. Oil IPR / TPC worksheets can be used to compare operating points between multiple pumps, or contrast ESP performance to natural flow and other artificial lift selections.

Allocate commingled production for layer characterization and modeling

Analyze wells that intersect multiple formations with commingled production. After inputting commingled rates and flowing pressures along with allocation factors, rates and pressures are calculated for each layer. Each layer can then be characterized, modeled, and forecasted. Individual layer forecasts can be aggregated to produce a total well forecast.

Integration with the conventional multi-well (CMW) model

- If the wells included in a CMW model are multilayered, historical production and sandface flowing pressures for individual layers can be displayed on the model's plots. This enables you to history match not only the well data, but the layer data too.
- If the wells included in a CMW model are multilayered, there is an option to automatically configure layers in the model from the well's layers. This reduces the need to type the same information multiple times, and supports consistency between the layers in the model and layers of the individual wells.
- Simulated layer rates generated by the multilayer CMW can be easily copied to the Multilayer Allocation editor of the corresponding wells.

Minor improvements and resolved issues from Harmony Enterprise 2021.3

General

- When creating a scenario, you now have the option to create an empty scenario, or replicate the existing well / scenario analyses and worksheets.
- Fixed Editor panes that were occasionally collapsing to a width of zero.

- Fixed the error "Custom attribute could not be found. It may have been removed". It was being incorrectly reported when creating an input custom attribute.
- When consolidations are added via a workflow, the analysis name is incremented to prevent duplicate names.
- The Add Worksheet tab has been modified to support high-resolution displays.
- Fixed inconsistent calculated sandface pressures when a wellbore configuration exists prior to the start of production.
- Errors in Optimize Configurations do not prevent sandface pressures from being calculated.
- Fixed MPP and Flow Percentage displayed as editable within a wellbore configuration.
- Fixed discrete bubble maps within Spatial Explorer so that a bubble is displayed for all wells with a value for the parameter specified.
- Fixed failing to load an .hldb file in Spatial Explorer, if the .hldb file was relocated since it was last opened.

Imports + Exports

- Choke Diameter can now be mapped when configuring a database connection import.
- WELL_KEY values are now compared in a case-insensitive manner to support source databases with inconsistent case between values.
- The active hierarchy structure is now always included when exporting to an .hldb file.

Forecast

- After adding probabilistic declines via a workflow, R^2 results are now available in the Results tab.
- Changing b for a decline analysis via a line manipulation no longer locks this value.
- The decline parameter $d_{i \tan}$ has been added to the parameters grid within the Reporting sub-tab.
- A S_{gi} value of 0 is no longer displayed as erroneous within oil volumetrics analyses.

- Fixed a crash when using the zoom tool on the voidage replacement ratio (VRR) history plot.
- Fixed a crash in VRR if a fluid on the history plot is deselected and then reselected.
- Fixed a crash when deleting a VRR pattern if the child wells were deleted.
- Fixed unsupported analyses being displayed on Typewell worksheets when added via a workflow.
- Default probabilistic analysis names can now include hyphens.

Reservoir

- Polygons created in Spatial Explorer can be directly imported to CMW as model boundaries. This allows for detailed and precise boundaries to be defined with minimal effort. Polygons are manually drawn or traced automatically from shapefiles and other layer types in Spatial Explorer.
- TPC Stabilization has been added to numerical models. This function automatically switches from wellhead to sandface pressure forecasts when the TPC operating point is found to be in an unstable flow region. This can be toggled off within the Options dialog box.
- Fixed the numerical unconventional reservoir model (URM) not synthesizing when running on Windows 11.
- The Np value displayed in URM was sometimes incorrect (it was Np at the end of history, though it should be Np at the Forecast Start Date). Now the Np value displayed in URM always corresponds to the Forecast Start Date.
- The forecast grid within models has been modified to support high-resolution displays.
- RF_{cond} is now populated within Forecast Results for gas condensate numerical models.
- Skin on fracture face now defaults to 0 in horizontal multfrac numerical models.
- Fixed a crash that occurred if production rows were added / modified in the Production editor after viewing a Typecurve.
- Fixed a crash when using the clipboard to populate an analytical model from an existing analysis.
- Synthesis in numerical models now starts consistently when you initiate it.

Optimize

- Advanced Forecast annotations have been improved to display more forecast step-specific information.
- Wellbore configurations can be copied to Optimize Configurations within the popup Wellbore editor.
- Fixed a crash if an Advanced Forecast worksheet was opened after using the Liquid Loading Monitor.
- The Liquid Loading Monitor no longer displays erroneous liquid loading onset at step one of the forecast.
- Multiphase choke correlations no longer require a GOR to calculate the default specific heat ratio.

Harmony Enterprise 2022.1 Release Notes

Transfer data from Kingdom

Using the newest functionality added to Spatial Explorer, you can transfer select reservoir properties from Kingdom's Zone Attributes directly into Harmony Enterprise. You can add a Kingdom project to Spatial Explorer and select which Zone Attributes from which wells you want to transfer. The reservoir properties that can be transferred are net pay, porosity, and saturations (oil, gas, and water).

Choke calculator

With the new choke calculator, you can determine the minimum upstream pressure requirements to maintain line pressure, study the impact of varying choke diameter on critical flow rates, and solve for downstream temperature to predict icing on the flowline.

Note: This tool is in active development, and we plan to incorporate it in both the tubing performance curve (TPC) and Flowing Gradient worksheets. We welcome feedback on this tool to guide future development.

Analytical wellhead model-based IPR

The Advanced Forecast worksheet has been enhanced to support the creation of model-based inflow performance relationship (IPR) curves using analytical wellhead forecasts. This feature is available for all supported wellbores and model types.

Optimize configurations

You can now create Optimize-specific wellbore configurations for use in Optimize worksheets. This avoids impacting non-Optimize calculations and analyses, including sandface pressure calculations or Reservoir models. Optimize configurations can be created and updated without having to leave an Optimize worksheet.

Numerical URM enhancements

To improve the usability of Harmony Reservoir's newest interpretation method, the following enhancements have been added:

- Data smoothing on Base Linear Model rates to reduce the impact of noise in sandface flowing pressures.
- OFIP stems show a range of OFIP_{SRV} for matching past the end of linear flow.
- Auto Match to fit the OFIP_{SRV} of the boundary-dominated flow curve.
- Connection to the data filter used by other Harmony Reservoir analyses.
- Calculate FCD' from ΔP_s .
- Numerical unconventional reservoir module (URM) results are now available in Analytics Explorer and Spatial Explorer.

Sandface pressure calculation includes injection support

Gas and water injection rates can be honored when calculating sandface pressures. Whether injection rates are included is controlled by a project-level setting in the Options dialog box.

Final version to support *.harmony imports

This is the last release that supports import of *.harmony files (from Harmony 2014v1 - 2016v3). This capability will not be available in the 2022.2 release.

Windows 11 supported

This version has been tested with and supports Windows 11.

Minor improvements and resolved issues from Harmony Enterprise 2021.3

General

- The Harmony Database Manager verifies that you have sufficient database privileges before running an upgrade, as otherwise a subset of the upgrade statements can fail.
- When extracting to an .hldb file, the Shared Settings found in the Options dialog box are now copied from the originating project.
- The initial size of the Bulk Editor dialog box has been increased so that all columns are visible by default.
- Sorting in the Bulk Editor persists after deleting or renaming analyses or worksheets.
- For plots or datasets copied to the Comparison Plot with mid-period plotting, the tails extending to the start and end of production persist.
- A warning is displayed when deleting worksheets and analyses. If the "Do not show again" option is selected, this setting persists when the application is restarted.

Imports + Exports

- When Enerdeq wells are combined by API, an option has been added to aggregate overlapping production periods across multiple production IDs, instead of the default behavior (to concatenate records and treat overlapping production as duplication).
- Fixed errors when importing low-frequency production over high-frequency data.

Forecast

- Added an option in the Bulk Edit Declines dialog box to shift the forecast start date to the end of each well's historical production for the selected decline analyses.
- Calculated ratio forecasts — the analysis show / hide setting and line customizations (color and thickness) persist.

Reservoir

- Permeability calculations in flowing material balance (FMB) — after estimating a well's productivity index (PI) and selecting flow geometry (radial or linear), permeability is calculated. This option is only available for single-phase FMB.

- Numerical models previously allowed multiple maximum rate constraints to be entered, but only one was honored. Models are now limited to one max rate constraint.
- The abandonment rate or pressure constraint is now honored in numerical models when the forecast starts within historical production.
- Fixed URM Typecurve plot scaling where the y-axis scale resulted in the data not being visible.
- Fixed the numerical model history match, which was not completing when adsorption was enabled until the well was reopened.
- The option "Enable Transient Boundary Diagnostic" on Agarwal Typecurves is now selected by default for new worksheets.
- Fixed failing numerical model synthesis when custom tables were used for all property correlations.
- Fixed a crash in Probabilistics that occurred if the regional decimal separator was set to comma (rather than a period).
- The Results Viewer now includes condensate recovery factor values from multi-well numerical models.
- Fixed the crash in numerical models when running automatic parameter estimation (APE) with x_e or y_e selected and x_w / y_w defaulted to half of these values.
- Various improvements to numerical wellhead forecast calculations.

Optimize

- Advanced Forecast — the Model Forecast now updates upon entering the Advanced Forecast worksheet, consistent with the other forecasts.
- Model-based IPR curves are now stored while remaining in the Advanced Forecast worksheet; no unnecessary recalculation is required while remaining in the worksheet.
- Switching from correlation-based to model-based IPR auto-calculates the IPR for the current forecast step.
- In the Flowing Gradient worksheet, you can now toggle between Tubing and Annulus within the Details table for the "Both" flow path.

Harmony Enterprise 2021.3 Release Notes

Introducing Spatial Explorer

Spatial Explorer enables direct collaboration between geoscientists and engineers by connecting them on a common mapping interface between Harmony Enterprise and Kingdom. Data is dynamically loaded from these projects, rather than spending time loading data that can quickly become stale. This first release of Spatial Explorer includes the following capabilities:

- Multi-attribute maps: build bubble maps using numerical and/or text attribute data that dynamically updates as the data changes or new wells are added.
- Well and zone attributes from Kingdom: ensure that Harmony Reservoir analyses are based on the latest geologic interpretations and computations by visualizing well properties and zone attributes determined in Kingdom. Harmony analysis results can also be displayed for comparison.
- Geologic maps – grids, contours, and faults: overlay grids, contours, and faults generated in Kingdom with Harmony Enterprise data to help make better engineering decisions.
- Well survey / deviation survey: overlay Kingdom deviation surveys on Harmony Enterprise wells.
- Mapping and GIS – ESRI integration: push and pull your organization's data to and from Spatial Explorer to the ARCGIS Portal. Share information from Kingdom and Harmony Enterprise with geology, geophysics, and engineering (GG&E) teams and publish relevant data to shapefiles and other databases. Connect your outside data sources including a variety of data types like shapefiles, WMS, map services, feature services, SDE databases, and more.
- Print presentation-quality maps: print shared maps directly to high-resolution PDFs. Create custom shareable templates for easily reproducible maps.
- Ease of collaboration: eliminate the time-consuming and error-prone process of sharing static data files with a single dynamic map hosting geoscience and engineering data for discussion, analysis, and presentation.

Numerical URM

The numerical unconventional reservoir model (numerical URM) analysis was developed based on URTeC-2020-2967-MS and accounts for multiphase behavior, including changing total compressibility when pressure drops below saturation pressure. Similar to the traditional URM analysis, numerical URM is used to determine the linear flow parameter (LFP or $Ac\sqrt{k}$) and size of stimulated reservoir volume (ASRV or OFIPSRV).

Surveillance / VRR

Harmony Forecast now includes a dashboard worksheet for the voidage replacement ratio (VRR). The VRR analysis helps identify parts of a field where more or less water must be injected in order to reach or maintain VRR targets.

- A map can be used for pattern creation based on well locations and to show the overlap between patterns.
- Oil material balance is available as a pressure source for changing fluid properties over time in the VRR calculation.
- Each VRR worksheet is fully independent; therefore, scenarios for pattern grouping, allocations, and pressures can be conducted on a single group.

Oil IPR / TPC – Liquid Composite IPR

Enhance your oil well's nodal analysis by capturing the total liquid rate. Dashed outflow lines represent operating pressure for tubing performance curves (TPCs) and liquid composite inflow performance relationships (IPRs). This analysis uses straight-line water IPR.

Minor improvements and resolved issues from Harmony Enterprise 2021.2

General

- Since working on an .hldb file from a network drive is not recommended and can result in file corruption, a warning dialog box is displayed each time you connect to this type of file on a network drive. Note that this dialog box includes the option to back up the .hldb file.
- Performance has been improved when applying a workflow directly to a well, which is now more comparable to applying the workflow in bulk.
- Performance has been improved when a project includes a hierarchy structure referencing a custom attribute. (This affected many tasks, such as importing, creating / duplicating scenarios, filters, etc.)
- Fixed removing a dataset from a plot, which previously left the dataset checked in the tree structure (incorrectly indicating it was being plotted).
- The P10 / P50 / P90 lines have been fixed in the Results Viewer CDF plot to intersect the curve.

Imports + Exports

- Database import support has been added for text columns stored as NVARCHAR(MAX), which previously resulted in a crash.
- The Pressure Source column now initializes consistently when using the “Discard and Replace” option compared to importing a new well.
- Performance has been improved when navigating to the Assign Mapping dialog box when creating a new database connection.
- Fixed an issue importing a *.harmony file, where worksheets and analyses were skipped for a well if it had a WOR analysis that used a ratio forecast from it.
- The Biot effective stress coefficient now updates following an import if it previously used the default value.

Forecast

- The first segment’s start date of a decline analysis is now only shifted forward if an asymptote occurs within the production row associated with this date.
- Resolved a crash that occurred when pasting a decline analysis to a typewell worksheet of a different fluid type.
- Fixed applying a WOR analysis via a workflow while water cut is set as the abandonment criteria.

Reservoir

- Adding an additional forecast row no longer results in a full model recalculation; only the forecast is synthesized.

Optimize

- IPR / TPC – color-coded TPC: easily distinguish outflow series with unique colors for TPCs. This is available for both oil and gas IPR / TPC worksheets.
- Model-based IPR curves are retained on the plot when the global units are toggled.

Harmony Enterprise 2021.2 Release Notes

Advanced Forecast – numerical model support

Create and compare multiple numerical model forecasts. Sensitize potential forecast conditions (such as, sandface flowing pressure or production rates) to maximize your well’s production. This

applies to sandface forecasts only.

Advanced Forecast – analytical model-based IPR

Leverage your analytical model to generate inflow performance relationship (IPR) curves at any point in your well's forecast using Advanced Forecast. This applies to sandface forecasts only.

Wellhead forecasting for single-well numerical models

Control your numerical models with wellhead pressure. With this enhancement, you can incorporate wellbore flow rates and pressure losses into numerical models, forecast into the future using a specified wellhead pressure constraint, or apply changes to wellbore configurations in the forecast to compare potential wellbore intervention strategies.

Bulk update the forecast start date

After updating production, use the Bulk Edit Declines dialog box to shift the forecast date to the end of production for all selected wells and analyses.

Minor improvements and resolved issues from Harmony Enterprise 2021.1

General

- The aggregate of the selected wells can be displayed on the Diagnostics tab by clicking an icon on the toolbar.
- A utility has been added to the Startup page to compact and defragment an .hldb file. This can improve performance, and minimize the .hldb file size to stay below the 10 GB limit. If the .hldb file size is close to the limit, upgrades to a new version can fail.
- New permissions are available when configuring role-based security:
 - Delete Scenarios — the permission to delete wells and scenarios has been split into two permissions.
 - Modify Existing Database Connections — you can allow users to import from an existing database connection but not edit the mapping or units.
 - Export to .hldb file — you can prevent users from extracting wells to an .hldb file.
- The gas rate unit Mscf/hr is available for imports or when displaying a gas rate in a plot or grid.

- A context menu has been added to the Monitor tab grids to copy results for use in third-party applications.
- Custom datasets can now be renamed.
- Fixed the Lee, Gonzalez, and Eakin gas viscosity calculations for liquid-rich gases where changing CGR could calculate incorrect gas viscosity values.
- Fixed a sandface pressure error. If the date of a wellbore configuration matched the date of a production record, the prior wellbore configuration was incorrectly used until the subsequent production row.
- The username and password for SQL users are now encrypted when saved.

Imports + Exports

- Additional data types are supported through Database Connection imports:
 - Static Pressures
 - Geomechanical properties
 - Specify “Pressure Source” within PRODUCTION_HISTORY
- In the Options dialog box, you can specify the default display name format for new wells.
- Updating data settings are displayed and can be modified when starting an import.
- The IHDC connection has been expanded to support North America and Canada in query data settings.
- Fixed an error where duplicate rows were being inserted (failing the import) even though they did not exist in the import source.
- Fixed an issue where adding wellbore configurations changed the active temperature profile from detailed to linear.

Forecast

- Reimplemented the decline initial best fit option using last X% of data as an alternative to Autoforecast.
- Fixed classified declines incorrectly being included in Reporting parameter grids when the “View Analysis” checkbox was deselected for the associated reference date.

Reservoir

- Single-well numerical models are now able to account for gas adsorption within the reservoir, including the adsorbed gas saturation correction.
- Recovery factor (RF) is displayed for each phase within single and multi-well numerical models.
- When using the defaults manager to initialize a numerical model with inputs from an unconventional reservoir model (URM), if no F_{CD} value is specified, 1000 is used.
- Fixed the persistence of constant pressure URM interpretation when the well has no historical flowing pressure data.
- Fixed the crash when forecasting a numerical model without specifying a forecast constraint.

Optimize

- Flow path and tubing can be customized when paired with a wellhead IPR.

Active directory

Microsoft's active directory provides a variety of directory-based identity-related services. Harmony Enterprise pulls information from active directory for Status Window messaging, role-based security, and group assignments.

Note: Your database administrator (DBA) adds active-directory groups via the SQL Server Management Studio.

Important considerations

When DBAs set permissions, these items need to be considered:

- Individual permissions supercede group permissions. For example, if you have permission to import data and the group you are assigned to does not, you are still able to import data.
- Groups at the same level in the hierarchy, roll up / concatenate permissions. For example, if you belong to group ABC with import rights but no delete rights, and also belong to group 123 with delete rights, you have both import and delete rights.
- By default, individuals in a group receive all the same permissions as those set at the group level.
- If you remove all of the roles for an individual, they inherit the default roles. In order to have an individual inherit group permissions, you have to delete the user's login name.

Note: At this time, we support active directory groups that contain individuals, not other active directory groups.

User permissions in local folders

Harmony Enterprise saves and uses data in local folders throughout various processes while you work. If you do not have "write" permission to these folders, it can interfere with normal operations and negatively impact your projects. On startup, Harmony Enterprise checks for write access to the required paths. Ensure you are able to write to these locations for optimal use of Harmony Enterprise.

Logging directory: \Users\\AppData\Local\IHS_Inc\

This directory is used to store a running log file for Harmony Enterprise, including many software and database transactions. This log file is *not* the same as the Status Window log file.

"My documents" directories:

- \documents\fast
- \documents\fast\Core
- \documents\fast\Core_Attributes
- \documents\fast\AdvPropsCMDLL_GlobalImport
- \documents\fast\AdvPropsCMDLL_GasProperties
- \documents\fast\AdvPropsCMDLL_OilProperties
- \documents\fast\AdvPropsCMDLL_WaterProperties
- \documents\fast\AdvPropsCMDLL_GeoMechanical
- \documents\fast\AdvPropsCMDLL_RelativePermeability
- \documents\fast\HarmonyAnalysis
- \documents\fast\ImportData\ProductionEditor
- \documents\fast\EnterData\ProductionEditor
- \documents\fast\Database Connection
- \documents\fast\HarmonyEnterprise
- \documents\fast\HarmonyEnterprise 20XX.X\ScheduledImportLogs

Database management

Database management instructions apply to database owners (DBOs) and administrators.

- [Create a database](#)
- [Enable role-based security](#)
- [Add groups / users to your database](#)
- [Configure well security](#)
- [Upgrade an existing database](#)
- [Defragment a database](#)
- [Release orphaned wells](#)
- [Troubleshooting](#)

Create a database

To create a database:

1. Run the Harmony Enterprise Database Manager.
2. In the Create Database tab, type the following information:
 - **Server Name** — the address of the server you are trying to connect to, typically <hostname>\<ServerInstanceName>.
 - **Server Port** — the port number your server is set up on. Leave this field blank to use the default setting.
 - Select **Windows Authentication** or **SQL Server Authentication** and type your Login ID and Password.
 - **Database Name** — the name of your database.
 - **Role Based Security** (checkbox) — select this option if you want [role-based security](#) (RBS).
 - **Additional Superuser** — if RBS is enabled, you can opt to authorize a super user to modify roles for other users (in addition to the database administrator). The login for the super user is typically <Domain>\<Username>. If this field is blank, no super user is added.

Note: If you select the **Create DSN File** option, you can browse to a location where the DSN file is created.

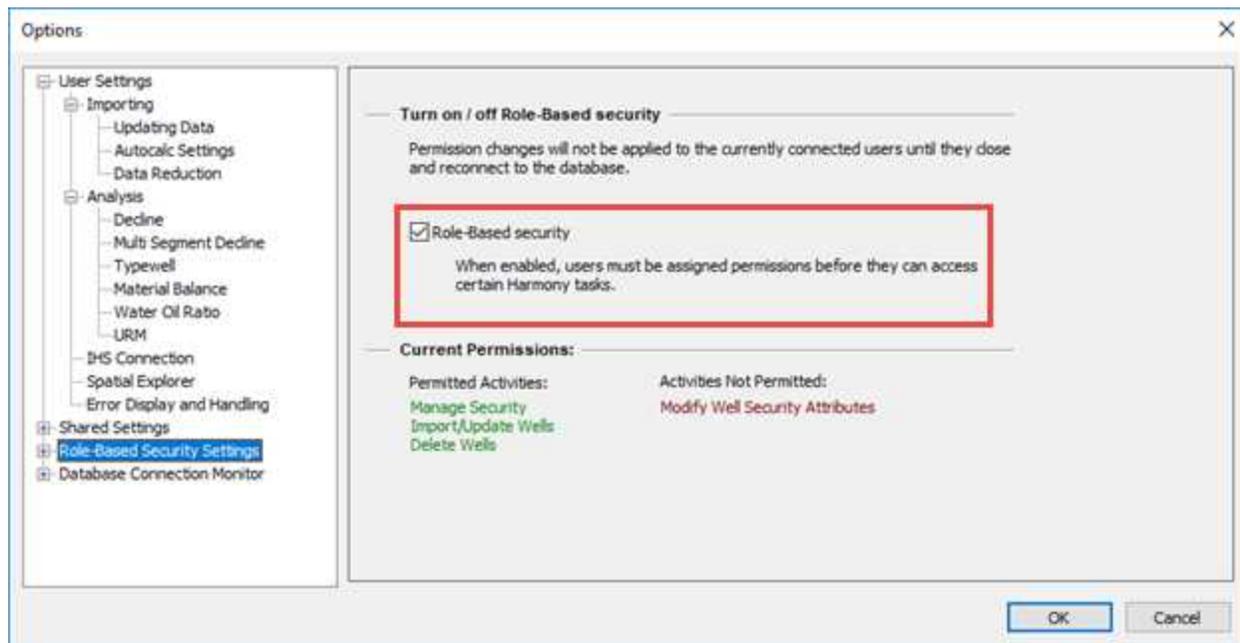
3. Click the **Create Database** button.

A message confirms if the database has been created. The new database immediately attempts to upgrade itself to the latest version.

Enable role-based security (RBS)

To enable RBS with an existing database:

1. Open Harmony Enterprise as a database owner, or user with the Harmony Security database role.
2. Connect to your existing database.
3. Click the **Options** icon (⚙️) in the main toolbar and enable role-based security.



Adding groups or users to your database

After you have created or upgraded your database, you need to grant access to the database. You can add groups or users to your database in two ways:

- via the Harmony Enterprise Database Manager
- via SQL Server Management Studio

Important: This topic is *not* applicable to cloud databases.

Using the Harmony Enterprise Database Manager

To add groups or users to your database:

1. Run the Harmony Enterprise Database Manager.
2. Click the **Users and Groups** tab and type the following information:
 - **Server Name** — type the name of your SQL server.
 - **Server Port** — if you leave this field blank, the default port is used.
 - Select **Windows Authentication** or **SQL Server Authentication** and type your Login ID and Password.
 - **Database Name** — if you leave this field blank, you can only add a SQL server login.
 - **Authentication** — select **Windows Authentication** from the drop-down list and type your Username / Group.

Or, select **SQL Server Authentication** from the drop-down list and type your Login ID and Password.
3. To add multiple users at the same time, click to enable the **Add Multiple Users** checkbox. Then type your information separated by commas.
4. Click the **Add Users** button.

Using SQL Server Management Studio

To add groups or users to your database:

1. Open SQL Server Management Studio and connect to your server.
2. On the left-side, navigate to <your server>\Databases\<your database>\Security\ and right-click **Users**.
3. Click **New User**.
4. Navigate to the General page.
5. Set the User Type to Windows User.
6. Type a User Name and Login Name:

- ensure these items match Windows login credentials, or the Active Directory group name.
 - credentials must already exist before they can be added to the newly created database.
 - the User Name and Login Name can be the same.
 - If you click the ... button, you can then click the **Check Names** button to verify that the credentials are entered correctly.
7. Set the Default Schema to **dbo** (without quotes).
 8. Navigate to the Membership page and click the **HarmonyUser** role.
 9. Click **OK**.

To assign additional users to be Harmony Enterprise Security administrators, you need to use Harmony's role-based security options to assign them the correct permissions. Assigning them the HarmonySecurity role using SQL Server Management Studio is not recommended, and at best only works temporarily.
 10. Repeat these steps for as many users as needed.

Configuring well security

Well security is used to restrict which wells a user or active directory group has access to.

These instructions are intended for database owners (DBOs) and administrators. In order to configure well-based security, you need the following:

- SQL 2016 or later.
- Role-based security (RBS) enabled. For more information, see [enabling RBS](#).
- Groups / users added to the Harmony SQL database with proper permissions (that is, with the Harmony User role).

To configure well security:

1. Browse to the WellSecurityManager folder and double-click the **WellSecurityManage.exe** file.

The Harmony Enterprise Well Security Manager opens.
2. In the Connection Mode pane, select one of the options to connect to your database.

- a. If you connected to a SQL server in the past, the Most Recently Used node displays content. Double-click a **Data Source Name** to open one of these connections.
- b. In the Server and Database Names node, type all the required information, and then click **Connect to database**:
 - **Server** — the name of your SQL server.
 - **Database Name** — the name you assigned to your database.
 - **User Name** and **Password** — type the credentials for the database.

To use your Windows login, click the **User Windows Authentication** checkbox.

- c. In the Data Source Name File Path node, click **Browse** and navigate to your .dsn file.
- d. In the Data Source Name List node, select the database you want to use. To use the ODBC Data Source Administrator dialog box, click **Open data source manager**.

The Group and Individual Users pane opens.

3. Ensure that Well Security is ON (); otherwise all users can access all wells.
4. In the Attribute Structure pane, drag attributes from the left box to the hierarchy on the right to create the attribute structure. You can select one-to-six attributes for security. Click **Continue**.

Note: If an attribute is a security attribute, it can only be edited in Harmony Enterprise by a DBO or a user with Manage Security permissions, or a user with Modify Well Security Attributes permissions.

5. Click a group () , user () , or security administrator () on the left-side, and select the attributes this user has access to. If you click the **All Present and Future Values** checkbox, all new attributes under the parent node are granted to the selected user, if these new attributes are imported later.

Note: A security administrator is a DBO or they have the Manage Security role, which means they are able to access all of the wells.

To edit the attribute structure, click the **Edit** button in the top right

Important: If you edit the security attributes, any security permissions previously set up are cleared.

6. When done, click **Save and disconnect**.

When you reconnect to your data source with Harmony Enterprise, deployment settings take effect.

Upgrade an existing database

When upgrading Harmony Enterprise to a new version, you must also upgrade any Harmony Enterprise databases.

Important: Follow the upgrade procedure after a Harmony Enterprise database is: a) upgraded from SQL Server 2014 to a more recent SQL Server version, or b) backed up and restored.

To upgrade a database:

1. Run the Harmony Enterprise Database Manager.
2. In the Upgrade Database tab, type the following information:
 - **Server Name** — the address of the server you are trying to connect to, typically <hostname>\<ServerInstanceName>.
 - **Server Port** — the port number your server is set up on. Leave this field blank to use the default setting.
 - Select **Windows Authentication** or **SQL Server Authentication** and type your Login ID and Password.
 - **Database Name** — the name of your database you are upgrading.
3. Click the **Upgrade Database** button.

A message confirms if the database has been upgraded.

Defragment a database

To maintain Harmony Enterprise database performance, we recommend occasionally defragmenting your database. At the minimum, defragment your database after an upgrade (unless your database administrator has a different maintenance schedule). We recommend defragmenting when no users are connected to the database outside normal business hours, so that the impact on Harmony Enterprise is minimal.

To defragment a database:

1. Run the Harmony Enterprise Database Manager.
2. In the Defrag Database tab, type the following information:
 - **Server Name** — the address of the server you are trying to connect to, typically <hostname>\<ServerInstanceName>.
 - **Server Port** — the port number your server is set up on. Leave this field blank to use the default setting.
 - Select **Windows Authentication** or **SQL Server Authentication** and type your Login ID and Password.
 - **Database Name** — the name of your database you are defragmenting.
3. Click the **Defrag Database** button.

A message confirms if the database has been defragmented.

Release orphaned wells

When a user has a well open, a lock is placed on that well. If for whatever reason, another user needs access to that well and the current user is unable to close the well and release the lock, you may have to manually release the orphaned well.

To release orphaned wells:

1. Run the Harmony Enterprise Database Manager.
2. In the Locks tab, type the following information:
 - **Server Name** — the address of the server you are trying to connect to, typically <hostname>\<ServerInstanceName>.
 - **Server Port** — the port number your server is set up on. Leave this field blank to use the default setting.
 - **Database Name** — the name of your database you are updating
3. Click **Manage Locks**.
4. Select the Entity Name (that is, well or scenario) to be released and click **Release Lock**. Repeat this step as needed.
5. Click **Close** when finished.
6. Notify any users that have had their lock revoked that they must reconnect to the Harmony Enterprise database before performing further work.

Troubleshooting

If you experience difficulties with your database, we recommend reviewing these common error messages and their solutions before contacting Customer Care.

When trying to create a new database with the database manager, I see this error: "There was an error with your input. Please ensure the server name and port you have provided are valid".

Verify that you entered in the correct server name and port.

These should be set up when you installed SQL Server and should be what you use to connect to the server when you start SQL Server Management Studio.

When trying to create a new database with the database manager, I see this error: "Database name already exists. Please try another database name".

The database name you have entered already exists as a database in your server. If you want to create a database with this name, either rename or delete the existing database first. To delete a database, right-click the selected database in SQL Server Management Studio and click Delete. You may have to select "Close existing connections", if there are any users connected to it at the moment. Note that as this step is IRREVERSIBLE, only do this if you have all your data backed up, and are completely sure you want to delete your database.

When I try to connect to the data source with the Harmony Enterprise application, I see this error: "cannot open the database; the login failed".

Did you remember to add this user to the newly created database?

For more information, see [add groups or users to your database](#). If you did add this user, verify that their information is correct. Also verify that your DSN is set up correctly.

- The driver should be "ODBC Driver 17 for SQL Server"
- Ensure the SQL Server connected to is the same as the one you created your database on
- Ensure that SQL Server uses the integrated "Windows authentication" for the login ID
- The default database should be the name of the database that you created

When I try to connect to the data source with the Harmony Enterprise application, I see this error: "Connection is not possible because the selected DSN file uses an unsupported authentication mode".

This message is displayed when you try to use an unsupported DSN file. To resolve this issue, see [connecting using the Data Source Manager](#).

*When I try to connect to the data source with the Harmony Enterprise application, I see this error:
"Database is out of date. Please upgrade your database before connecting".*

The Harmony Enterprise database is most likely out-of-date and needs to be upgraded. Double-click the DatabaseManager.exe file to upgrade the database to the latest version. This error message can also be present if you run an older version of Harmony Enterprise, but try to connect to the latest version of the database.

Harmony Enterprise in the cloud

You need a [full version](#) of Harmony Enterprise to use Harmony Enterprise on AWS. When running Harmony Enterprise on Azure, you can use either a full license or an [SE license](#).

We provide guidance for clients who want to set up Harmony Enterprise in the cloud. This guidance includes requirements and configuration information for cloud installation. If you have questions, [contact us](#).

Tip: If you want help setting up your cloud environment, recommended partner consultants are listed by [AWS](#) and [Azure](#).

This is a brief summary of our recommended setup:

- You can run Harmony Enterprise with Windows Virtual Desktop (Azure) or AppStream (AWS)
- The Harmony Enterprise SQL database is hosted with Azure SQL (Azure) or RDS (AWS)
- The Gemalto License Server is hosted on a virtual machine
- All the above resources must be set up in the same region and virtual network

Disclaimers

IHS Markit does not offer direct cloud hosting of Harmony Enterprise or services to set up a cloud environment.

We outline a recommended approach for setting up the Harmony Enterprise application (versions 2020.2 and later), its database, and license server. While other configurations are possible, they are not supported by IHS Markit.

We reference [Microsoft Azure](#) and [AWS](#) options. Other cloud providers may be used in a similar fashion, but they have not been tested and verified by IHS Markit.

Assumptions

We expect that all of the components of the cloud environment are configured prior to installing software, licenses, database migrations, or builds. This includes a functional cloud environment with active directory (AD) configuration (if using AD sign on), database permission (both Harmony Project / Storage and any proprietary production databases), firewall settings, security group configuration, port openings etc.

Limitations

Be aware of the following:

- When running Harmony Enterprise on AWS, it connects via SQL databases, and users cannot connect to or create .hldb files. (Users can connect to and create .hldb files on Azure.) Note that users can still import or extract .hldb files while working in the cloud with the exception of AppStream instances.
- You cannot use standalone licenses when running Harmony Enterprise on the cloud (Azure or AWS).
- You cannot check out commuters when running Harmony Enterprise on the cloud (Azure or AWS).
- Well Security has been observed to perform poorly in some operations in cloud environments. At this time, we do not recommend using Well Security for cloud databases, and if it is required, users will observe better performance when connected as SQL users.
- The Well Security tool for managing well access cannot connect to a Harmony Enterprise database using Azure AD. On Azure, a SQL administrator user is required to manage Well Security.
- Analytics Explorer has not yet been confirmed as adequately connecting in cloud environments.
- Standalone licenses and commuters cannot be used in cloud environments.

Considerations for Management and IT

We strongly recommend working with qualified cloud architects and engineers for your cloud deployment.

- A thorough understanding of the total cost of ownership, the current environment, and the resource requirements on pre- and post-deployments are imperative for a successful migration. We recommend working with certified cloud architects and engineers for any cloud-related deployments.
- Existing issues must be addressed prior to migration. Moving to the cloud does not resolve system inefficiencies, poor database builds, or application performance.
- Database Support must be aware of the limitations, differences, and lack of certain features associated with managing and supporting databases in cloud environments.

- A proper change management process should be followed. We strongly recommend evaluating deployments in Development / Test environments, and getting user signoffs before migrating to production.
- A Harmony Enterprise user needs read-only access to the client’s proprietary production database, and write access to the Harmony Project / Storage database.
- Prior to migration, all users must be logged out of the Harmony Enterprise database.

Terminology

Important terms for Azure and AWS are as follows.

Azure

Term	Definition
Application Group	A logical container used to control which users have access to which remote applications and full desktop experiences in WVD. Each WVD host pool has one or more application groups associated with it.
Database Transaction Unit (DTU)	This is used by Azure for price models.
Host Pool	The collection of VMs associated with a WVD instance.
RDWeb	Microsoft’s technology for connecting users to session hosts in a WVD host pool. Can be accessed through a browser or downloaded as a desktop client application.
Session Hosts	The VMs in a WVD instance’s host pool. Session hosts are VMs, but the term is used to distinguish them from VMs that are not part of any host pool. Session hosts run a multi-session Windows 10 OS to allow multiple users to log in simultaneously.
Virtual Network (Vnet)	A representation of your network in the cloud.
Windows Virtual Desktop (WVD)	Microsoft’s desktop and app virtualization service, using multi-session Windows 10 virtual machines (VMs). Users connect using RDWeb rather than connecting directly to a specific VM in the host pool.

AWS

Term	Definition
AppStream 2.0	Amazon’s fully managed application streaming service. Capable of streaming multiple sessions of the application to multiple users simultaneously. Allows Harmony Enter-

Term	Definition
	prise to be used in a browser window.
EC2	Amazon’s Elastic Compute Cloud (EC2) is a web service that can be used to create virtual machines running various operating systems on the cloud.
RDS	Amazon’s Relational Database Service is a web service that allows a user to operate various relational database systems on the cloud.

Recommended specifications

Recommended Azure and AWS performance specifications are as follows.

Azure

The performance requirements for Harmony Enterprise running in Azure are highly dependent on how many concurrent Windows Virtual Desktop (WVD) users you expect to have, and how demanding their workloads are. In the table below we provide rough guidelines for selecting your virtual machine (VM) database specifications, but we encourage you to experiment with the following parameters to find a combination that provides the best balance of performance and cost savings for your organization.

- Number of session hosts — you can add more VMs to spread your users across more hardware
- ‘size’ of session host VMs — you can select a size with more RAM and vCPUs if your performance is sluggish
- Database vCores — you can modify the min / max vCores for your Azure SQL DB to increase database throughput, if for example, users find that it takes too long to save and load well data.

Component	Configuration	Comments
WVD session hosts	Standard D8s v3	8 vCPUs, 32 GB memory
Database Server – Windows 2016 Data center (SQL Server 2014 & higher)	General Purpose: Gen5, 8 vCores	
Azure File Share	2 GB of allocated space per WVD user	You may need to increase your file share, if your user’s FSLogix profiles grow over time
License Server	Standard_B1ms	Standalone VM, always on

AWS

AppStream 2.0 must first have a base image created with Harmony Enterprise installed and configured. The base image is then used to create a “fleet”. A fleet spins up instances for each user that connects, which means the number of users should not affect the fleet performance, provided the fleet has been configured with desirable performance levels.

As such, an important parameter that needs to be considered is capacity. This is the number of instances that are on, which equals the number of users that can connect to the fleet at a given time. AppStream 2.0 has auto-scaling, which can increase or decrease capacity as necessary. For more information, see [AWS documentation](#).

Component	Configuration	Comments
AppStream 2.0 Fleet	stream.memory.xlarge	Make sure to specify minimum and maximum capacity, as necessary
RDS Database with SQL Server (with your choice of SQL Server Edition)	db.t3.large	Allocate enough space for your database needs. Note that SQL Server Express Edition only supports a maximum of 10 GB. SQL Server 2016 or later is necessary for well-based security.
License Server	t2.micro EC2 Instance	Simple license server, always on

Connection requirements

Connection requirements are as follows.

Port rules / IP

Component	Configuration	Comments
Database Server	1433 default (Inbound) / Protocols / TCP/IP Services Enabled	Confirm with DBA, if the port number was changed
License Server	UDP - 5093 (Inbound) / Static IP / Protocols	

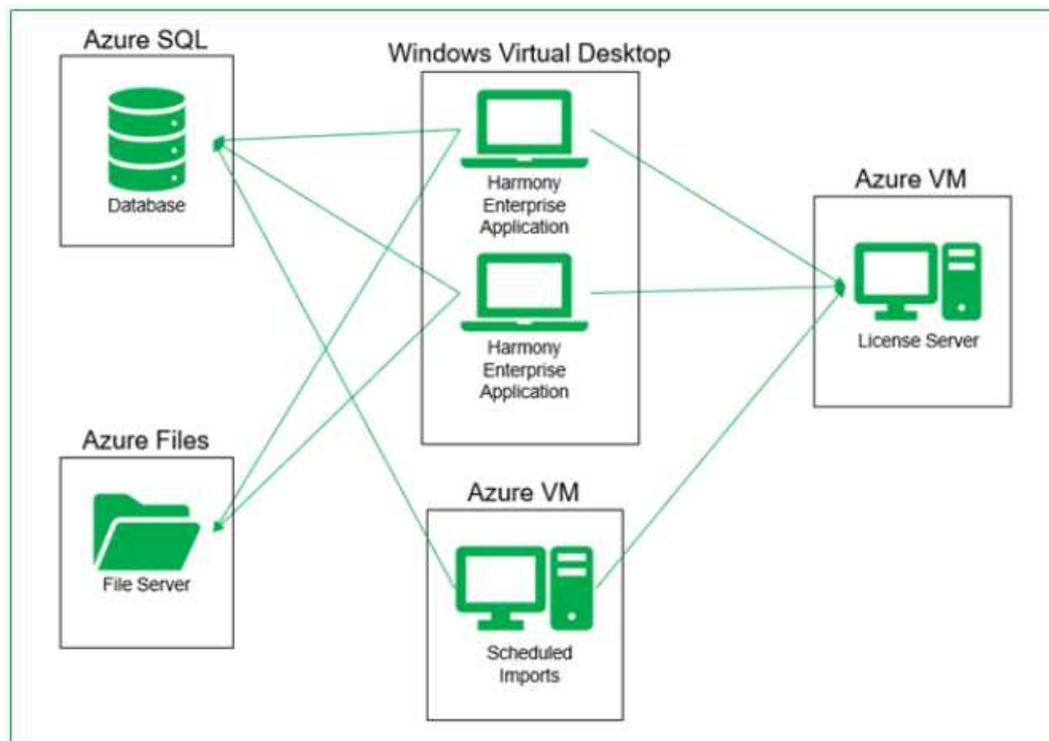
HTTP / HTTPS

Ensure the following are not blocked by your cloud setup. You may need to add a DNS to your Vnet such as Google's 8.8.8.8.

Service	Endpoint	Comments
Enerdeq	webservices.ihsenergy.com	Used for the Enerdeq login within Harmony Enterprise
IHDC	directconnectapi-ca-cal.ihs.com	Used for the IHDC login within Harmony Enterprise
EMS	https://softwarelicensing.ihsmarket.com/ems/	Used for activations / deactivations of Harmony Enterprise entitlements

Microsoft Azure

Azure's recommended architecture is as follows.



Azure components are described below.

Cloud component	Purpose
Azure VM – License Server	A dedicated VM where the Gemalto License Service is installed.
Azure SQL	An Azure SQL database to store the Harmony Enterprise database. The Azure

Cloud component	Purpose
	SQL Managed Instance is <i>not</i> supported.
Azure Files	Storage for FSLogix user profile containers
Windows Virtual Desktop	A scalable host pool of dedicated VMs that provide a full Windows 10 desktop environment to users who connect via RDWeb to use Harmony Enterprise. In addition to Harmony Enterprise, each session host must have FSLogix installed to persist user profiles.
(Optional) Azure VM – Scheduled Importer	If scheduling imports to Harmony Enterprise, there must be a dedicated VM with Harmony Enterprise installed. This VM is where the scheduled imports are performed.

License server setup

The Gemalto License Service must be running at all times to serve licenses to Harmony clients, so you need to install it on a dedicated VM that is not part of the WVD host pool and leave it on 24/7. Because the License Service consumes so few resources, you can choose a low-spec VM to run it on. We recommend the Azure VM size Standard_B1ms for this purpose.

Windows Virtual Desktop (WVD)

WVD is a scalable and cost-effective alternative to individual cloud virtual machines (VMs) for deploying software to many users in Azure. Each WVD host pool consists of multiple session hosts (VMs) that remain always-on, by default.

When users connect to WVD, their Windows user data is not automatically synchronized between session hosts. Some of this data is required by Harmony Enterprise to function correctly. This includes user-created templates and settings that are normally saved to a user's computer, rather than in a specific Harmony Enterprise database. A solution to this problem is to use a tool called FSLogix, which can persist user-profile data in another location, such as a file share.

Note: To get a good high-level technical understanding of WVD, FSLogix, and how they fit together, see [Windows 10 Enterprise multi-session FAQs](#).

For Microsoft instructions on WVD setup, see the following:

- [Create a VM from a managed image](#)
- [Software preparation and installation](#)
- [Create FSLogix Profile Container](#)

Microsoft is deploying rapid changes to WVD and sometimes the official documentation is out of date compared to the currently available functionality. Third-party tutorials may be valuable to assist you in completing the WVD setup process.

Creating your image

There are certain configuration steps that need to be applied to all WVD session hosts, so we recommend that you do these things at image-creation time, so that each user does not have to do configuration themselves.

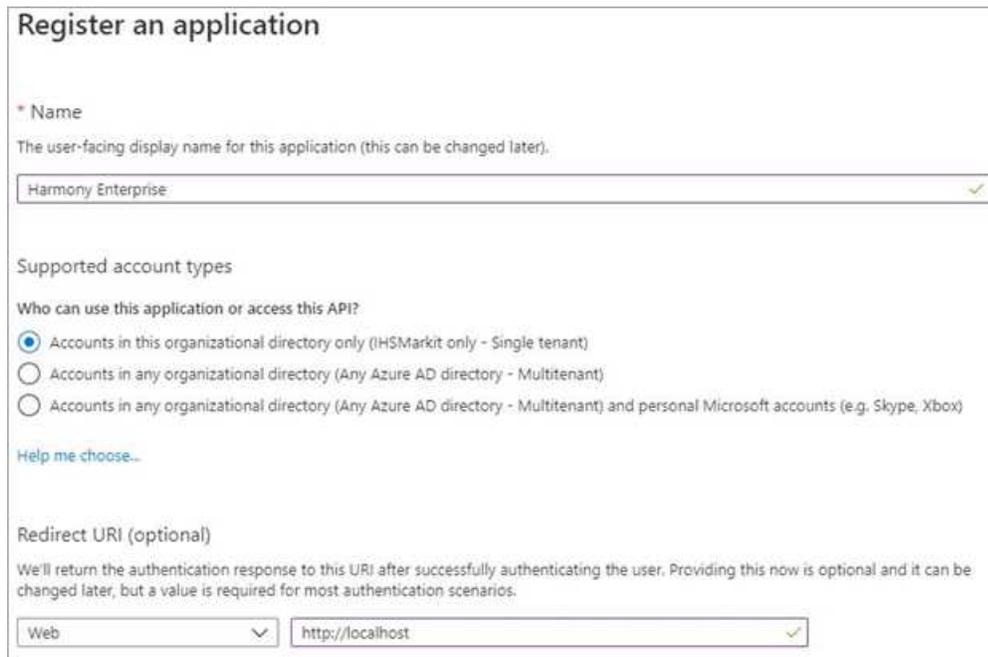
- After installing Harmony Enterprise on your master image VM, launch Harmony Enterprise and set the license server to the private IP address of the dedicated license server for the Azure VM you created earlier.
- Set up a system DSN for each Harmony Enterprise database that your Harmony Enterprise users need to connect to. For more information, see [connecting using the Data Source Manager](#).

Note: All WVD users use the license server and system DSNs that you configure in this image, so if you want to change these items, you need to create a new image version with your changes, and deploy it to new session hosts.

Application registration (for Azure active directory)

Active directory (AD) authentication requires Harmony Enterprise to be registered as an application to your Azure tenant. Consult with your organization's Azure AD administrator if you need assistance.

Application registration can be very simple. For example, a single-tenant with a localhost URI is sufficient.



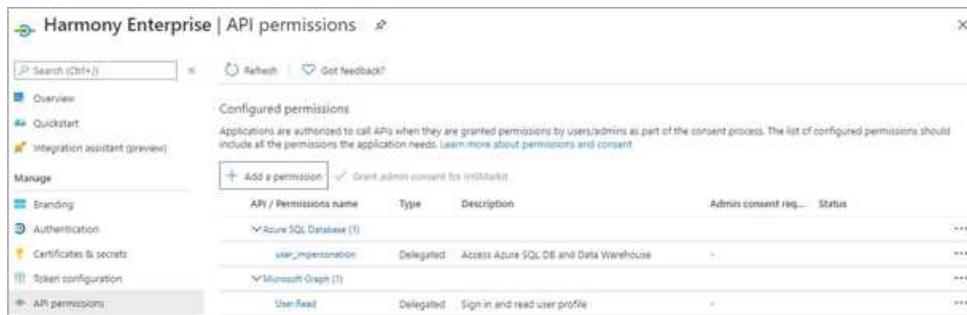
Register an application

* Name
The user-facing display name for this application (this can be changed later).
Harmony Enterprise ✓

Supported account types
Who can use this application or access this API?
 Accounts in this organizational directory only (IHSMarkit only - Single tenant)
 Accounts in any organizational directory (Any Azure AD directory - Multitenant)
 Accounts in any organizational directory (Any Azure AD directory - Multitenant) and personal Microsoft accounts (e.g. Skype, Xbox)
[Help me choose...](#)

Redirect URI (optional)
We'll return the authentication response to this URI after successfully authenticating the user. Providing this now is optional and it can be changed later, but a value is required for most authentication scenarios.
Web ✓ http://localhost ✓

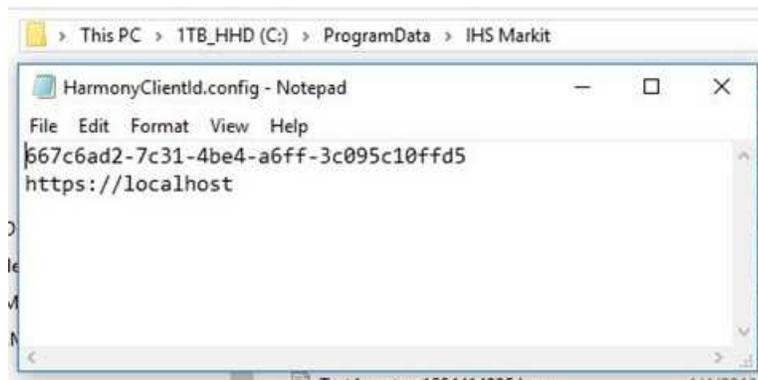
API permissions then need to be set on the registration. Add delegated user-impersonation for the Azure SQL server



Note that delegated permissions require an interactive login to be done for each user before Azure AD password-only or integrated authentications are allowed. To simplify the user experience connecting to Harmony Enterprise, you should consult with your organization's Azure AD administrator to grant tenant-wide administrator consent to the application. This enables users to work in Harmony Enterprise using AD-integrated or password-only authentication without requiring an initial interactive sign-on.

In order for Harmony Enterprise to use the registration, create a text file named *HarmonyClientId.config* in the *ProgramData\IHS Markit* folder on your computer, VM, or WVD image.

Paste the Application (client) ID to the first line, and the redirect URI to the second line as follows:



Azure file share

Before creating the Windows Virtual Desktop (WVD) host pool, you need to set up an Azure File Share to hold the FSLogix user profile data for your eventual WVD users.

You need to create a Storage Account and a File Share within that storage account in which to save the FSLogix user profiles. Ensure that your Harmony Enterprise users have sufficient IAM and NTFS permissions to access these resources.

Azure SQL

Azure SQL Server is a cloud-native variant of SQL Server that offers two main cost models: vCores and database transaction unit (DTU). IHS Markit has tested the vCores model and Harmony Enterprise is certified to run on this type of database.

vCores has two models: Provisioned and Serverless. Provisioned denotes that the software is allocated as always-on hardware and accrues a constant cost. Serverless solutions are not allocated hardware until a user requests service. The client only accrues costs per usage and costs for corresponding data storage. While less costly, serverless vCores are not as responsive or reliable as provisioned vCores.

To get started, see these procedures:

- [Creating a new Harmony Enterprise database](#)
- [Adding groups / users to your Azure database](#)
- [Migrating an existing Harmony Enterprise database to Azure](#)

Creating a new Harmony Enterprise database (Azure)

If you do not have an existing Harmony Enterprise database on-premises that requires migration into the cloud, you can create a blank one in Azure SQL by following these steps:

1. From the Azure portal, create an Azure SQL Server (if you do not already have one).

Note: You do not need to create a blank Azure SQL database as the Harmony Enterprise Database Manager can do that for you.

2. From either an on-premises computer that has access to the Azure SQL database, or from an Azure VM in the same Vnet, use the Harmony Enterprise Database Manager to create a new Harmony database.

- a. Install the Harmony Enterprise Database Manager.

- b. Launch the Harmony Enterprise Database Manager.

- c. In the Create Database tab:

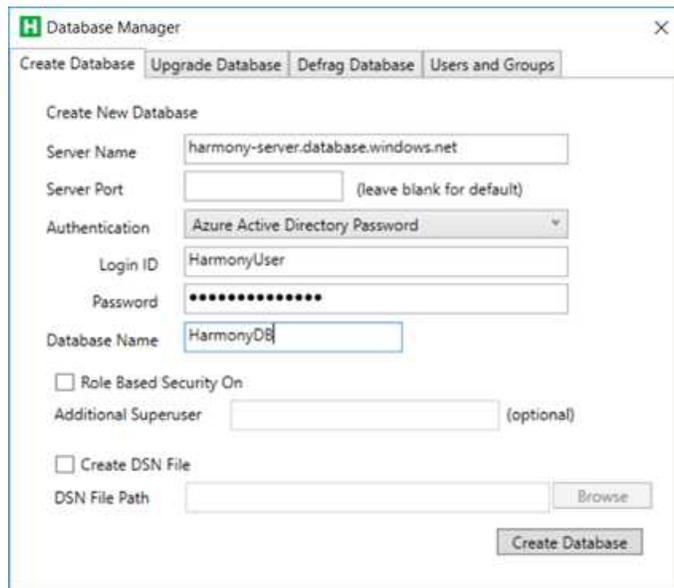
- Type the SQL server name. (You can find this in the Azure portal on the Overview tab of your Azure SQL Server.)
- Select your preferred authentication method and type your credentials.

Note: We recommend using the Admin SQL Login to create the database rather than the Active Directory Admin account since the Active Directory Admin may change to a different user, and you may lose access to the server.

- Type a Database Name.
- If you intend to use role-based security (RBS), enable it now. You can also give another user permission to set up and modify RBS permissions for all Harmony Enterprise users (that is, the Additional Superuser option).

Note: If you intend to have a user manage RBS permissions for all of the other users, you *must* add this user as a Superuser at this point in the procedure.

- When you are done, click the **Create Database** button and wait for the process to complete.



Adding groups or users to your Azure database

We recommend adding groups / users to your Azure database using the Harmony Database Manager:

1. Launch the Harmony Database Manager.
The Harmony Database Manager utility opens.
2. Click the **Add Users and Groups** tab.
3. In the Connect to Database section, type the credentials you want to use to connect to the database. This account must have access to the database and have permission to add users to the database.

Note: In order to add Azure Active Directory (AD) users, you must be connected via one of the Azure AD Authentication methods, preferably with the Azure AD administrator account.
4. In the Add Users or Groups section, specify the authentication type for the group(s) or user(s) to be added. Note that for Azure SQL, the Harmony Database Manager only adds Contained Users to the database — meaning there are no associated logins created on the server. This is different from a non-Azure SQL database, which adds both a login and a user. If a user already exists, the utility skips creating a new user and attempts to add the user to the required database roles.

- a. If you want to add Azure AD users, select **Windows Authentication**.
 - b. If you want to add SQL users, Select **SQL Server Authentication**.
5. Specify the Username / Group. An example of an Azure AD domain name is:
FirstName.LastName@myazuredomain.com.
6. Click **Add Users**.

A contained user is created on the database and is given the proper roles to access the database through Harmony Enterprise.

Migrating an existing Harmony Enterprise database to Azure

Migrating your on-premises Harmony Enterprise database to Azure SQL is a two-step process: first use the Microsoft Data Migration Assistant (DMA) tool to perform the primary migration, then use the IHS Markit script to migrate users and repair database objects that the DMA tool is not capable of migrating.

Step 1: Migrate with the DMA tool

To perform the primary migration:

1. Back up your existing Harmony Enterprise database.

Note: Ensure that all Harmony Enterprise users have disconnected from the database before backing up. Otherwise, wells that are being edited can become permanently locked.
2. Upgrade your database to the latest version.
 - a. From an on-premises computer, install and launch the Harmony Enterprise Database Manager. Make sure the Database Manager version and the Harmony Enterprise version are the same. (Harmony Enterprise 2020.2 is the earliest version that supports cloud deployment.)
 - b. In the Upgrade Database tab, type the server name, database name, and your authentication information. Click **Upgrade Database** and wait for this to complete.
3. In Azure, create a blank database as the target for your migrated Harmony Enterprise database. To do this, open the Azure portal, go to the SQL server instance you intend to use, and click **+ Create database**.
4. Use the Microsoft Data Migration Assistant (DMA) tool to perform the migration.
 - a. Download the DMA tool and install it.

- b. Click the + icon and start a new migration. Select **Schema and data** for Migration scope.
 - c. “Select source” step: Connect to your source server and select the Harmony Enterprise database to be migrated.
 - d. “Select target” step: type the Azure server name. You can find this in the Azure portal in the top-right of the SQL server’s Overview tab, under “Server name” (for example, my-harmony-sql-server.database.windows.net). Type your admin SQL server login info and click **Connect**. Select the target database where you want to migrate your data.
- Note:** Windows-authenticated users may see errors beside their names, and the HarmonyCertificate1_User is ineligible for migration. Do not worry about these errors because they are corrected in step 2: user migration and database repair.
- e. The resulting generated script needs to be modified.

- Copy the entire generated SQL script and save it as a text file on your computer.
- Open a Powershell window and navigate to the directory where you saved the SQL file.
- In the code snippet below, replace <FILENAME> with the name of the SQL file you just saved, then copy and paste the code into the Powershell window and run it:

```
( Get-Content -Path ".\<FILENAME>.sql" ) -replace "AS \[db_owner\]", "AS [dbo]" -replace "TO \[db_owner\]", "TO [dbo]" > ".\<FILENAME>_modified.sql"
```

- Open the <FILENAME>_modified.sql file, and copy-and-paste the contents back into the DMA tool, replacing the original auto-generated SQL. Then, click **Deploy Schema**.
- “Script & deploy schema” step: After the schema deployment is finished, click the **Export** button to save the results of the schema deployment to disk as a JSON file. This file is useful for debugging, if there are problems with the migration. Click **Migrate data**.
- “Select tables” step: Click **Start data migration**. Wait for the migration to complete. When a “migration complete” message is displayed in the lower right corner, you can close the DMA tool.

Step 2: User migration and database repair

Microsoft’s DMA tool is not capable of migrating certain critical parts of the Harmony Enterprise database, such as users. IHS Markit has created a powershell script which *must be run* after the

DMA tool's migration.

Our scripts migrate SQL logins and users, and convert all Windows users in your on-premises Harmony Enterprise database into Azure Active Directory users in your Azure SQL target database. Additionally, the tool makes necessary modifications to your migrated database to ensure that Harmony Enterprise features continue to function correctly after migration. However, we recommend that you do not migrate any users named "admin", as this is a reserved user in the target database, and it does not migrate from the source as expected.

Note: This migration process does *not* migrate Windows groups. You need to recreate these manually in the cloud, and re-assign any Harmony Enterprise role-based-security permissions

From a computer that has access to both your on-premises Harmony Enterprise database and your target Azure SQL server:

1. Install Powershell 7. It can be installed alongside your existing powershell version, if needed.
2. On your local drive, go to: C:\Program Files (x86)\IHS Markit\Harmony Enterprise <version 20.2 or higher>\Database Manager\Cloud. Open the file **runPostMigration.ps1** in a text editor, or independent development environment (IDE).
3. Replace the function arguments in this script with your own.
4. Launch Powershell 7 and navigate to where the ps1 script is saved. Type in the following and click **Enter**: `./runPostMigration.ps1`
You may be prompted to install the sqlserver module for Powershell. When the script is finished, a SQL file is generated.
5. Follow the instructions at the top of the generated SQL file to learn how to run the file on the target migrated database.

Note: All SQL users' passwords are changed to *Harmony!1234567890* by running these migration scripts.

Scheduled imports

With Harmony Enterprise, you can perform scheduled database imports from your proprietary database. In an on-premises environment, any Harmony Enterprise user with sufficient RBS access can set up a scheduled import, which creates a task in the Windows Task Scheduler to run

an import. Typically, this takes place overnight, or over the weekend when the user is not using their computer.

However, as a WVD user, you cannot schedule an import because Windows Virtual Desktop (WVD) logs you out when your session ends, and the task cannot run without the session running.

To perform scheduled imports, you can create a dedicated Azure virtual machine (VM) with Harmony Enterprise installed. We recommend using SQL authentication (rather than Azure AD authentication) to connect to the Harmony Enterprise database from this VM, and then create a scheduled import from there. This ensures that the scheduled import does not prompt anyone for Azure active directory (AD) credentials when trying to connect to the Harmony Enterprise database.

To reduce costs, you can use one of the many available methods to script the [starting / stopping](#) of this VM, so it is only active during the hours when you expect scheduled imports to be running.

Troubleshooting (Azure & Harmony Enterprise)

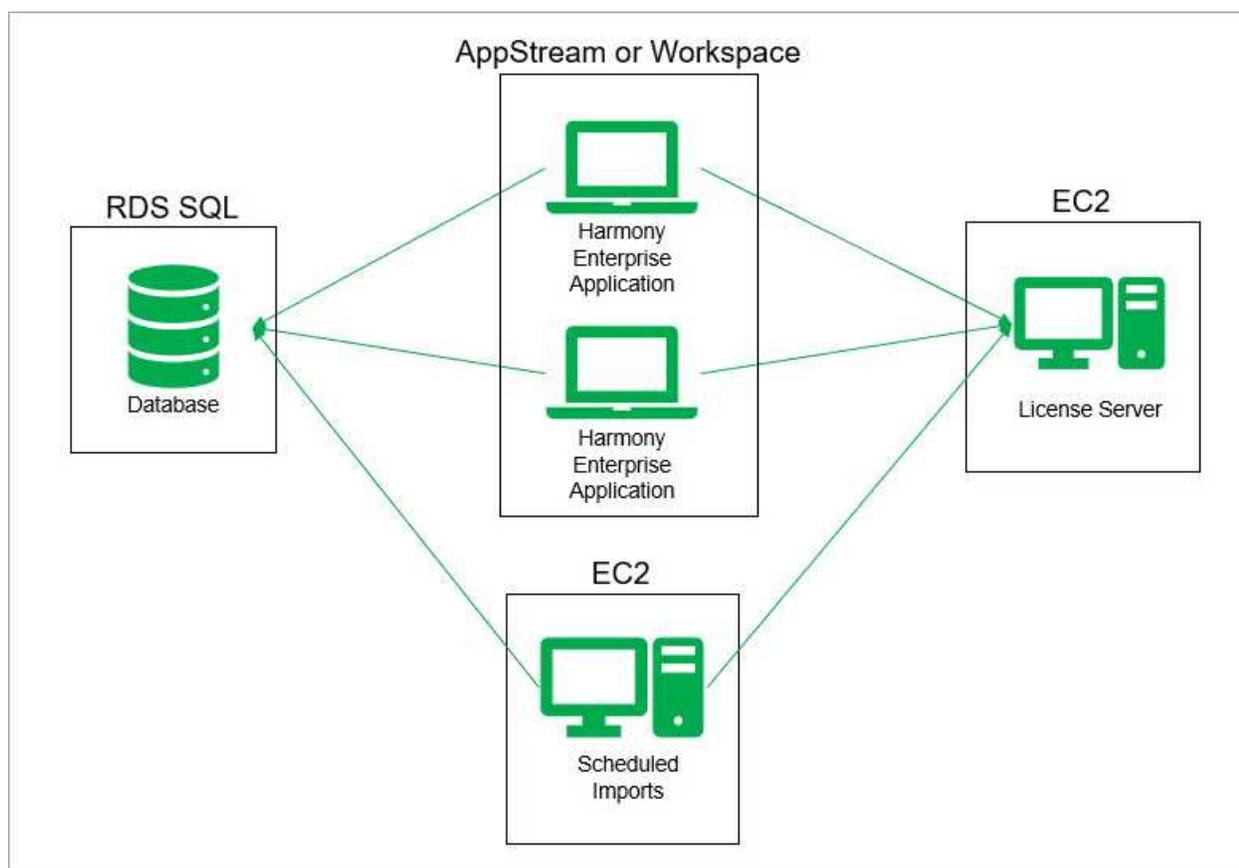
Troubleshooting information for Azure and Harmony Enterprise is as follows:

Problem	Probable cause	Solution
You cannot perform Enerdeq and/or IHDC imports.	The subnets which host the VM instances are expected to have internet access. Otherwise, they are not able to access resources such as Enerdeq and IHDC, help documentation, or EMS.	Ensure that the Vnet where your VM and/or WVD session hosts are connected to has a public DNS server (for example, Google's 8.8.8.8 in the list of DNS servers). Otherwise, Harmony Enterprise is not able to find these third-party resources.
When trying to connect to your Azure SQL Harmony Enterprise database, Harmony Enterprise displays the error "Unable to complete login process due to delay in login response".	Your Azure SQL database may be configured as "Serverless" (as opposed to "Provisioned"), and has gone into sleep mode after a period of inactivity.	You can configure the sleep time in the Azure portal. Double-click the connection in the Harmony Enterprise start page, and the Azure SQL DB should exit sleep mode after about a minute. Now, you should be able to connect.
You cannot upgrade the Harmony Enterprise database inside Azure SQL from 2020.2 to the subsequent version using a SQL login.	If you migrated your database from on-premises to Azure, then SQL logins were all migrated as Contained Database users. This means they do not have server-level access.	Try using Active Directory (AD) authentication in the Harmony Enterprise Database Manager. You must use an AD account that has sufficient IAM permissions to interact with the server.

Problem	Probable cause	Solution
User-profile information keeps disappearing for WVD Harmony Enterprise users.	Either FSLogix is not configured correctly, or your users do not have sufficient permission to access the file share where the FSLogix profiles are stored.	Ensure your users have sufficient permission to access the file share where the FSLogix profiles are stored.
When setting up a database connection in Harmony Enterprise, if you select “Select default database” from the drop-down-list in the ODBC wizard, you see a login error.	Harmony Enterprise database users are migrated to Azure SQL as Contained users. This means they no longer have server-level logins associated with them. The drop-down list requires server-level permission to view the list of databases.	Type, or copy-and-paste the name of your Harmony Enterprise cloud database into this field, rather than clicking the drop-down list.

Amazon web services (AWS)

AWS's recommended architecture is as follows.



We recommend you set up Harmony Enterprise on AWS by hosting the application through AppStream 2.0 with an RDS SQL server for the Harmony Enterprise database, and with EC2 to host the license server.

Note: Currently, Harmony Enterprise does not support .hldb files in AppStream 2.0, and functionality is disabled while on AppStream 2.0. If Harmony Enterprise users need to import or export .hldb files, you have to install Harmony Enterprise on an EC2 instance to do so.

License server setup

For Harmony Enterprise to access licenses, a license server needs to be set up. The License Service needs to be installed on an EC2 instance. This EC2 instance does not need to be efficient, and even a micro instance should be enough (assuming no other applications run from the same instance). The IHS Markit License Manager also needs to be installed, although it does not have to be on the same instance. The server is intended to be on at all times, although it is possible to

set the EC2 instance to start and stop based on a schedule. For additional information on how to start / stop EC2 instances on a schedule, see AWS documentation.

AppStream 2.0

Amazon AppStream 2.0 is a fully managed application-streaming service. You centrally manage your desktop applications on AppStream 2.0 and securely deliver them to any computer. You can easily scale to any number of users across the globe without acquiring, provisioning, and operating hardware or infrastructure.

Amazon provides a [tutorial](#) on building a custom AppStream image with your desired application.

During the setup process you can integrate with OneDrive for Business, or Google Drive for GSuite to provide your users with an easy way to access their files from inside AppStream. Or, you can enable local file sharing.

We strongly recommend setting any shared settings when you are in the Image Builder step. While Image Builder is open, launch Harmony Enterprise, and set the License Server to the private IP address of the [EC2](#) you created to run your license service. You may also want to set any shared settings such as System DSNs (see [connecting using the Data Source Manager](#)). Do this for the template user, test user, etc. Note that all users get the same settings from the base image. This image cannot be changed after it is created; it can only be recreated.

We also recommend adding **explorer.exe** as an application, so users can interact with the file system in a familiar way. Or, you can select a **Desktop Stream View** when setting up the fleet.

RDS for SQL server

Amazon's Relational Database Service (RDS) for SQL server is a scalable, flexible Platform-as-a-Service (PaaS) platform. An administrator can deploy in minutes cost-efficient and resizable compute capacity for multiple editions of SQL server including Express, Web, Standard, and Enterprise.

Amazon RDS offers services which include provisioning, backups, software patching, monitoring, and hardware scaling. The service supports the "License Included" licensing model. Pricing is a combination of per-hour instance fees, plus high-speed database storage and backup fees.

To get started, see these procedures:

- [Creating a new Harmony Enterprise database](#)
- [Adding groups / users to your RDS database](#)
- [Migrating an existing Harmony Enterprise database to RDS](#)

Creating a new Harmony Enterprise Database (RDS)

If you do not have an existing Harmony Enterprise database on-premises that requires migration into the cloud, you can create a blank one in [RDS](#) by following these steps:

1. Create an RDS database server with the Engine Type set as Microsoft SQL Server (if you do not already have one). This is the server where databases can be created.

Note: You do not need to create a blank database as the Harmony Enterprise Database Manager can do that for you.

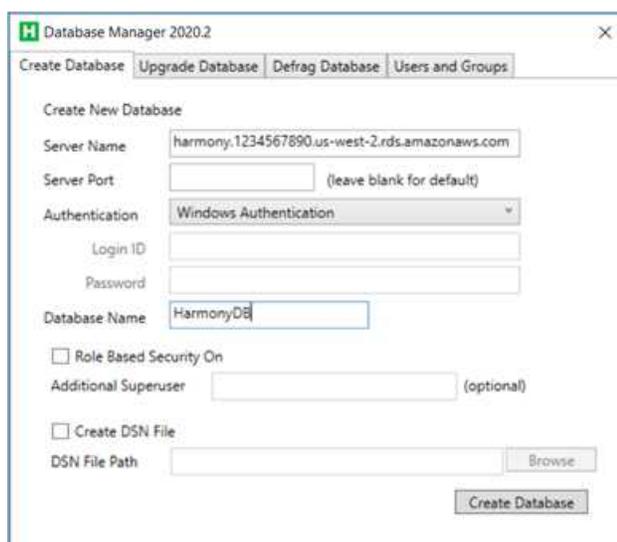
2. Install the Harmony Enterprise Database Manager on a computer that has access to RDS. (It can be on-premises, or in the cloud.)

3. Use the Database Manager to create a new Harmony Enterprise database:

- a. Launch the Database Manager

- b. In the Create Database tab:

- Type the SQL server name. (You can find this in the RDS console for the server you created in step 1.)
- Select **SQL Server Authentication** and type the administrator username and password that was specified when the server was created. (You can use another login with enough permissions, but the administrator SQL Login is guaranteed to have the required permissions.)
- Type a Database Name.
- If you intend to use [role-based security](#) (RBS), enable it now. You can also give another user permission to set up and modify RBS permissions for all Harmony Enterprise users (that is, the Additional Superuser option).
- When you are done, click the **Create Database** button and wait for the process to complete.



When you are done, click the **Create Database** button and wait for the process to complete.

Adding groups or users to your RDS database (AWS)

We recommend adding groups / users to your Relational Database Service (RDS) database using the Harmony Database Manager:

1. Launch the Harmony Database Manager.
The Harmony Database Manager utility opens.
2. Click the **Add Users and Groups** tab.
3. In the Connect to Database section, type the credentials you want to use to connect to the database. This account must have access to the database and have permission to add users to the database.
4. In the Add Users or Groups section, specify the authentication type for the group(s) or user(s) to be added. Note that the Harmony Database Manager adds both a login for the server, and a user associated with that login for the database with the same name. If a login already exists, the utility skips creating a user and attempts to add the user to the required database roles. If the user is orphaned (does not have a login associated with it), the utility attempts to reconnect the user to the login.
 - a. If you want to add Active Directory (AD) users, select **Windows Authentication**.
 - b. if you want to add SQL users, Select **SQL Server Authentication**.

5. Specify the Username / Group. (Make sure to include the AD domain name, if you selected Windows Authentication.)

6. Click **Add Users**.

A login for the server and a user for the database is created with the proper roles to access the database through Harmony Enterprise.

Migrating an existing Harmony Enterprise database to RDS

Before performing any migration, ensure that your on-premises database is updated to the latest version. This helps ensure a smooth transition to RDS. Ensure that no Harmony Enterprise users are connected to the database while backing up. Otherwise, wells that are being edited can become permanently locked.

To restore backups to RDS via S3, see the [AWS documentation](#).

Note: Do not use the Amazon RDS Migration Tool as it is not capable of fully migrating the schema, which could lead to problems and inconsistent behavior in Harmony Enterprise.

Warning: Do not re-use pre-existing .bak files from previous database backups because this results in large file sizes increasing transfer times and storage costs. Re-used files contain multiple restore points, which can cause AWS to import the incorrect database version. Ensure that your .bak file contains a single full database backup.

Migrating users

The migration process transfers the database users, but not their server-level logins. To migrate users from your on-premises database, you should use the migration scripts provided with the Harmony Enterprise installation (see the procedure below).

From a computer that has access to both your AWS RDS and on-premises Harmony Enterprise database, perform these steps immediately after the initial migration is complete:

1. Install Powershell 7. It can be installed alongside your existing powershell version, if needed.
2. On your local drive, go to: C:\Program Files (x86)\IHS Markit\Harmony Enterprise <version 20.2 or later>\Database Manager\Cloud. Open the file **runPostMigration.ps1** in a text editor, or independent development environment (IDE).
3. Replace the function arguments in this script with your own.

4. Launch Powershell 7 and navigate to where the ps1 script is saved. Type in the following and click **Enter**: `./runPostMigration.ps1`

You may be prompted to install the sqlserver module for Powershell.

When the script is finished, two SQL files are generated.

5. Follow the instructions at the top of each generated SQL file to learn how to run the file on the target migrated database. The files are numbered in the order in which they should be run.

Note: All SQL users' passwords are changed to *Harmony!1234567890* by running these migration scripts.

Scheduled imports: setup guide

With Harmony Enterprise, you can perform scheduled database imports from your proprietary database. In an on-premises environment, any Harmony Enterprise user with sufficient [RBS](#) access can set up a scheduled import, which creates a task in the Windows Task Scheduler to run an import. Typically, this takes place overnight, or over the weekend when the user is not using their computer.

However, as an AppStream 2.0 user, you cannot schedule an import since AWS logs you out when your session ends, and the task cannot run without the session running.

To perform scheduled imports, you should create a dedicated EC2 instance with Harmony Enterprise installed. There are many possible ways to do this, but one suggested method is as follows:

1. Create an EC2 instance and install Harmony Enterprise on it.
2. Create your Database Connection in Harmony Enterprise as per usual.
3. At the last step, instead of creating a scheduled task for the Windows Task Scheduler, select **Command Line**.
4. Using both the "Program" and "Command Line Parameters", create a script that can be run from the command line.
5. To set this script to be run on the EC2 instance on launch, see [running commands on your Windows instance at launch](#).
6. Schedule the EC2 to start / stop as you want. For more information, see [AWS Instance Scheduler documentation](#).

Troubleshooting (AWS & Harmony Enterprise)

Troubleshooting information for AWS and Harmony Enterprise is as follows:

Problem	Probable cause	Solution
When setting up Template users, you may see a “Copy Profile Failed” error message.	This is caused by a lack of proper permission for user data. For example, anything in AppData/Local can be considered user data.	Ensure that all user data and folders have read / write permission.
Warnings when accessing Internet Resources via EC2 instances.	Internet Explorer is automatically placed at the highest security settings, so most sites are not trusted.	It is likely that a dialog box opens prompting you to confirm if you trust a website. You can add the Harmony Enterprise help to the list of trusted websites.
When finalizing the Image Builder step, you may see a “Your Session Cannot be Started” error message.	This likely happens due to a timeout.	Despite seeing this error message, you should notice that your image still gets built successfully.
You are not able to access web-based resources such as Enerdeq and IHDC, help documentation, or EMS.		The subnets for the AppStream instances are expected to have internet access. When creating the subnets, ensure that they allow access to all required resources.
When changing some settings such as the License Server, the settings are lost when you start a new streaming instance.	Any data stored inside of %ProgramData% does not persist with the default AppStream 2.0 persistence (for example, the license server location, some logs, and a few other config files).	These settings should be set during the Image Builder steps. This ensures that all users have the same settings. Note that the log file is also saved at the same location. Therefore, you need to move the log file before you close the streaming session, if you want to send the file to technical support.
The Harmony Enterprise installer fails when it attempts to install .NET Framework 4.8.	Note that .NET Framework 4.8 may not install if you have an out-of-date version of Windows.	Get the latest Windows updates, if possible. If this is not possible, manually install .NET Framework 4.8 via the offline installer from Microsoft.

General considerations

There are capabilities in Harmony Enterprise that are affected by accessing the cloud's VM or image. The most common ones are listed below. If you are not sure whether these need to be considered in your cloud setup, speak with your users to understand their requirements.

Importing and exporting data

Harmony Enterprise imports data from files, databases, and web-based sources.

- If your users typically import from files, they need access and instruction on how to upload files to cloud storage, or access internal network locations from a cloud Harmony Enterprise instance.
- If imports are done from a proprietary company database, you should consider whether it makes sense to access an internal server hosting the database from the cloud, or if the database should be migrated to the cloud. Connections to a database for Harmony Enterprise imports are saved in the Harmony Enterprise database and can be preset for users to access as needed.
- If importing from Enerdeq or IHDC, internet access is required. To see which addresses need to be accessible, see [connection requirements](#).
- If exporting decline forecasts to a MOSAIC format, Microsoft Excel must also be installed.

Printing and reporting

Users should be able to print from Harmony Enterprise to a PDF on their cloud instance. Users should be instructed on how to move printed PDFs off the cloud to a local directory. Additionally, if printing to paper is required, the instance should be connected to local printers.

Templates and workflows

Users that have worked in Harmony Enterprise prior to cloud migration may have created templates and workflows specific to their processes. These are stored on their local machine and not in the Harmony Enterprise database. Templates and workflows must be migrated separately to maintain consistency after moving to the cloud.

In a local instance of Harmony Enterprise, click the **Tools** menu and select **Export Templates / Workflows**. This template file can be imported by a specific user in a cloud instance and persisted in their user data, or it can be used in part of the image created for all users.

Licensing

Harmony Enterprise is licensed on a per-module basis. A license for a given module grants you access to a set of analysis methods and features. For each module, there are two types of licenses available: standalone and network. At least one license is required to connect to a Harmony Enterprise database.

A standalone license is installed on your local machine. For information on standalone licensing, see [activating / deactivating licenses](#).

A network license is installed on a network server and Harmony Enterprise must request a seat from the network server. If you want to work offline, a network license can be checked out as a commuter, and is accounted for in the network license seat count. After you are finished working offline, you can check your commuter in, and release the seat. For information on setting up network licensing, see the [IHS Markit Installation Guide](#) and [License Manager help](#) (both links open in a new window / tab).

The Harmony Enterprise [startup screen](#) has a license icon for each module that indicates whether or not you have been granted a seat. For example, a green Harmony Forecast™ icon means that you have access to the Forecast module, while a grayed-out icon indicates that you do not have access. Clicking the **Forecast** icon, **Reservoir** icon, or **Optimize** icon opens the [Licensing dialog box](#).



Activating / deactivating licenses

For standalone licensing, you only need to install Harmony Enterprise.

To set up a network licensing system, you need to install the License Service on your server and the License Manager on one or more machines with connectivity to the server. For more information (including activation / deactivation information), see the [IHS Markit Installation Guide](#) (opens in a new window / tab).

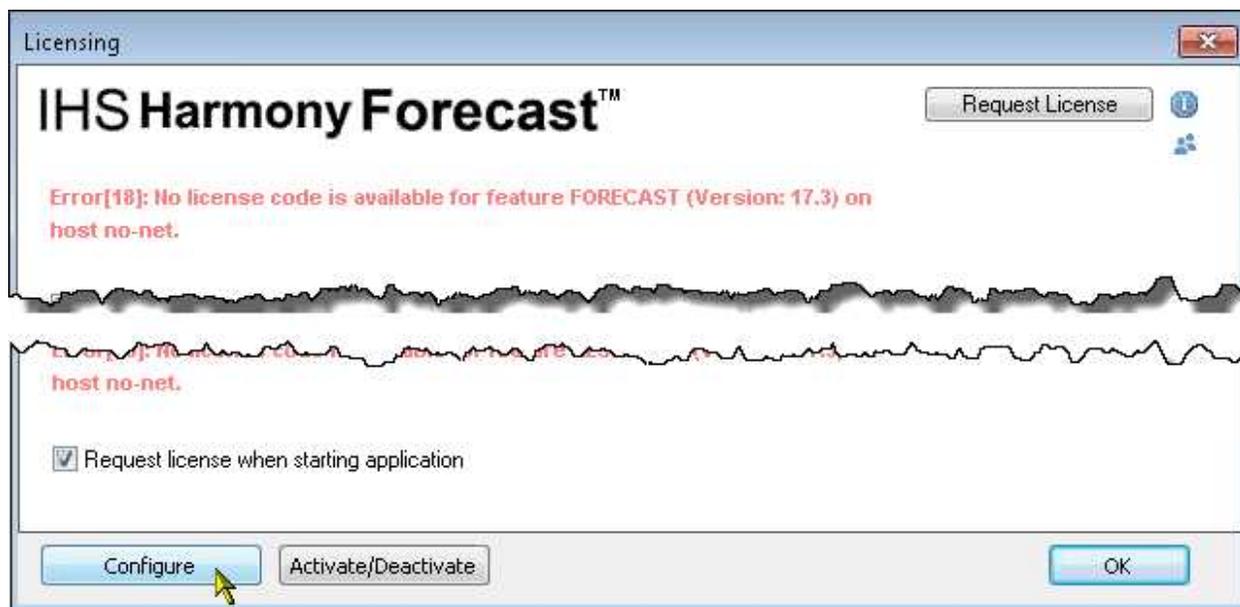
Best practice

For network entitlements, activate / deactivate licenses through the License Manager. For standalone entitlements, activate / deactivate licenses through Harmony Enterprise. Do not activate licenses using the EMS Customer Portal unless instructed to do so by a customer care representative.

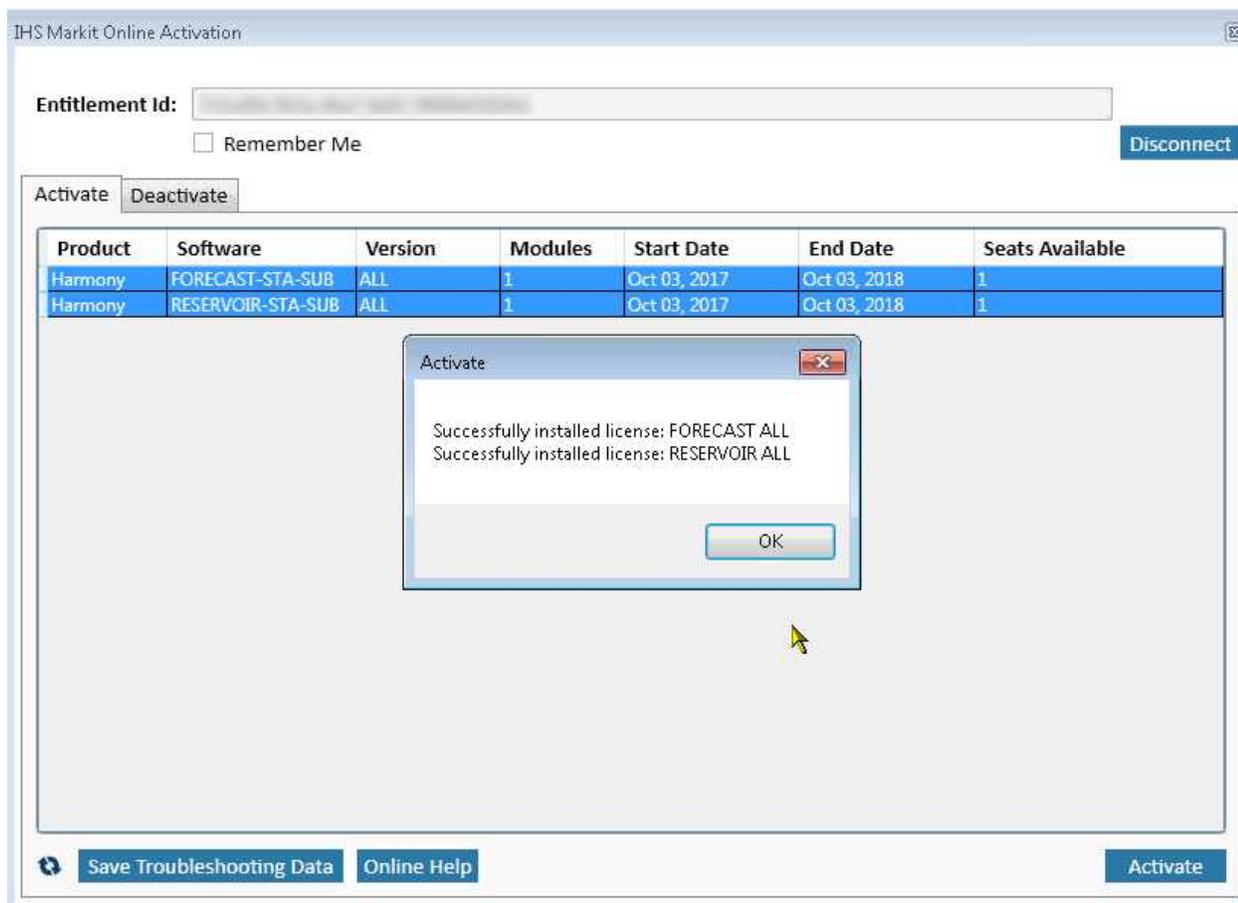
Activating / deactivating standalone licenses

To activate or deactivate standalone licenses:

1. Open your EMS - Entitlement Certificate email and copy your entitlement ID (EID).
2. Start Harmony Enterprise.
3. Open the Licensing dialog box by clicking either the **Forecast**, **Reservoir**, or **Optimize** icons in the startup screen.



4. Click the **Activate / Deactivate** button.
5. Paste your EID (from the email) in the **Entitlement Id** field and click **Connect**.
6. To activate licenses, in the Activate tab, select the products you want to use and click the **Activate** button. For information on setting up licensing for IHS Markit software, click the **Online Help** button, which opens the [IHS Markit installation guide](#).



Your licenses are now active.

Note: You can also queue up renewed licenses as soon as you have received your new entitlement email. There is no need to remove your current license, or to wait until your current license expires.

7. To deactivate licenses, in the Deactivate tab, select the products you want to deactivate and click the **Deactivate** button.

The products are now displayed in the Activate tab and can be activated on a new machine.

When the deactivation process completes, a dialog box opens indicating whether the process was successful or not. If the network experiences an interruption during the deactivation, a "Complete Partial Deactivation" button may appear. When the network is restored, clicking this button cleans up any artifacts caused by the interruption, and then the button disappears.

Licensing dialog box

This dialog box enables you to configure standalone or network licensing.

Standalone licensing



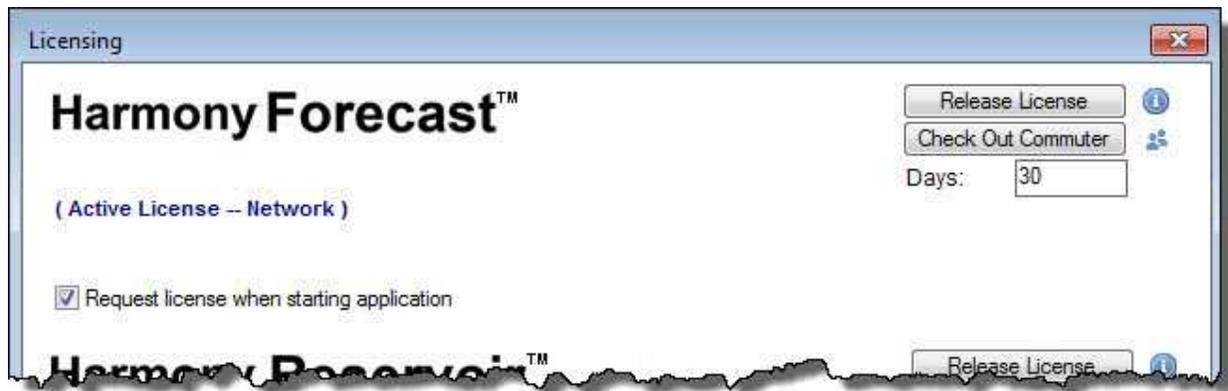
Active License -- Standalone — indicates that your license is ready for use. Note that if your license is not active, errors are displayed for troubleshooting purposes.

 **Information** icon — opens the [License Information dialog box](#).

Configure button — opens the [Licensing Settings dialog box](#) where you can configure your licensing (for example, you can install or uninstall a license that has already been activated).

Activate / Deactivate button — opens the [IHS Markit Online Activation dialog box](#) where you can activate and deactivate your licenses. For more information, see [activating / deactivating licenses](#).

Network licensing



Active License -- Network — indicates that your license is ready for use. Note that if your license is not active, errors are displayed for troubleshooting purposes.

Request license when starting application checkbox — click this checkbox to automatically request your seat when Harmony Enterprise opens. If you click this checkbox before you have a network seat, a seat is requested. Note that this checkbox may be hidden by your administrator.

Release License button — releases your network seat. This button is only visible if you use a network license seat, and this button is only enabled if more than one seat is used, because Harmony Enterprise requires at least one seat to be used.

Note: A network license has a specific number of network seats, each of which allow one instance of Harmony Enterprise to run. In addition, a network seat can be commuted, which enables you to work offline.

Request License button — requests a network seat. Note that this button is only visible if you do not have a network license seat.

Check Out Commuter button — enables you to work offline by commuting a network seat. (This button is only visible if you have not checked out a commuter.)

Days field — use this field to set the number of days your commuter can exist offline. By default, you can check out the commuter for a maximum of 90 days. Note that this field is only visible when the Check Out Commuter button is displayed.

Check In Commuter button — click this button when you are finished working offline to check your commuter back in. (This button is only visible if you have checked out a commuter.)

 **Information** icon — opens the [License Information dialog box](#).

 **Current Users** icon — opens the Current Users dialog box, which lists all current users, machine names, start dates, and if users' licenses are commuters. (Commuter licenses enable you to work offline.) This list of current users can be useful if you are trying to track down a seat that could be made available. If the Commuter column lists "Yes", the user is likely away from the office.

Note that this icon may be hidden by your administrator.

Configure button — opens the Licensing Settings dialog box where you can configure your licensing (for example, you can set the name of your network license server).

Activate / Deactivate button — opens the IHS Markit Online Activation dialog box where you can activate and deactivate your licenses.

You need at least one license to run Harmony Enterprise; as a result, if only one license is active, the Release License option is grayed-out.

License Information dialog box

This dialog box is accessible from the Licensing dialog box.



At the top, the name of your licensed module is displayed. Beneath this, the following information is displayed:

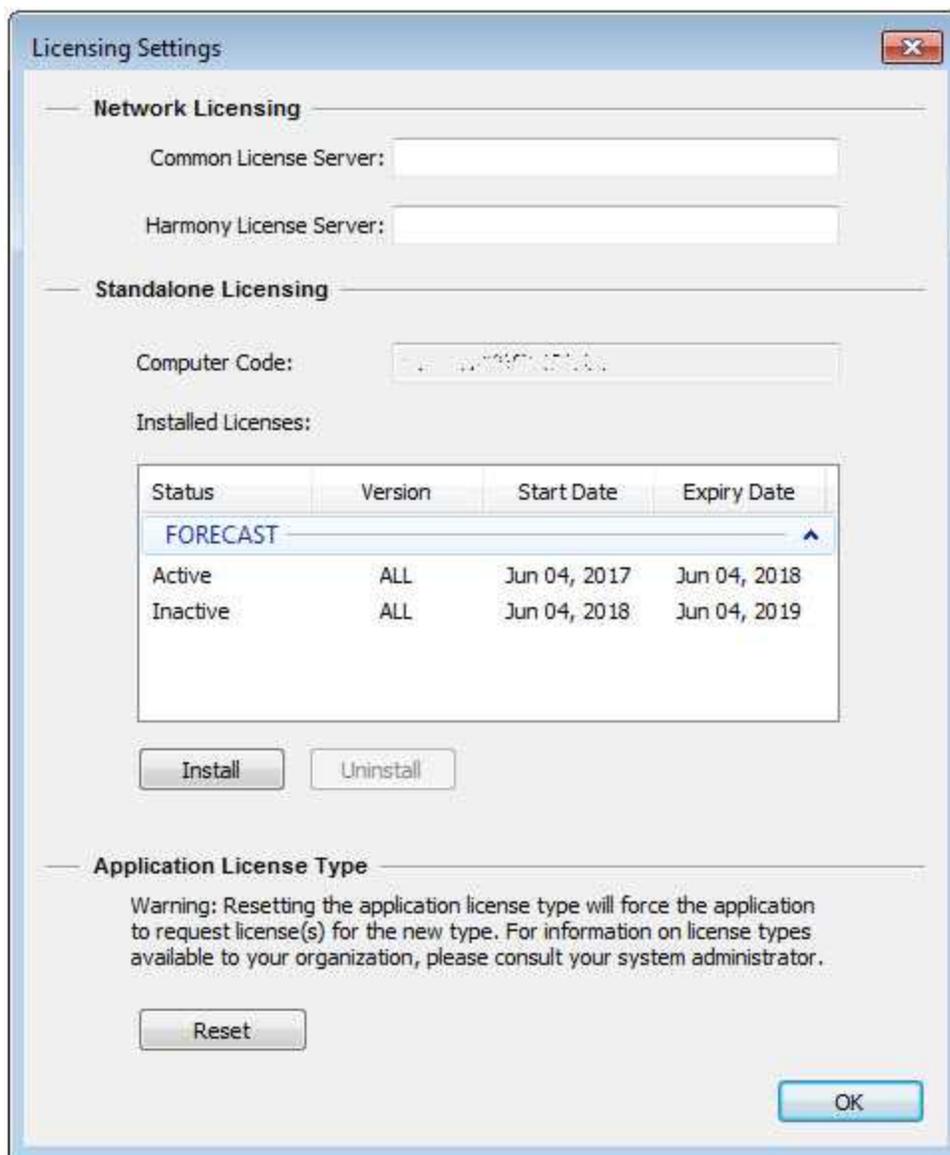
- **Application Version** — the build number for Harmony Enterprise
- **Feature Version** — indicates whether or not a license is version locked. A version of ALL indicates that a license is *not* version locked and can use any

version of Harmony Enterprise compatible with the Gemalto licensing system. Version locked licenses (for example, perpetual licenses) have a version number, and can use all versions of Harmony Enterprise compatible with the Gemalto licensing system up to and including the version number specified.

- **License Type** — indicates a network or standalone license
- **License Start Date** — the first day the license can be used
- **License Expiry Date** — the last day the license can be used
- **License Library Version** — the build number for the license library
- **License Service Version** — the build number for the license server (only visible for network systems)

Licensing Settings dialog box

This dialog box is accessible from the [Licensing dialog box](#).



Network Licensing

Use this section to specify the location of your network license server. If you are hosting all of your IHS Markit network licenses (for applications using the Gemalto licensing system) on the same server, use the Common License Server field. If you have separate servers for Harmony Enterprise and other IHS Markit applications, use the Harmony License Server field.

Note: If you fill in both fields, the Harmony License Server field takes precedence.

Standalone Licensing

Computer Code field — this is the hardware footprint for your computer. It is only required if you need to activate a license using the customer portal. For computers with internet access, see [activating / deactivating licenses](#).

Installed Licenses — lists all of the standalone licenses currently activated. This section shows active licenses, as well as inactive licenses (expired or future licenses that are queued up).

Install button — click this button to install standalone licensing that you have activated using the customer portal.

Uninstall button — if you want to uninstall standalone licensing on your local computer, click this button. Note that standalone licenses that are uninstalled with this button are not available for activation on other computers. If you want to move a standalone license to another computer, it must first be deactivated, and then activated on the new computer. For more information, see [activating / deactivating licenses](#).

Application License Type

Reset button — if you have purchased the full version of Harmony Enterprise and want to switch from SE, click the Reset button. For more information, see [overview](#).

IHS Markit Online Activation dialog box

This dialog box is accessible from the [Licensing dialog box](#) and displays content after you connect to the Entitlement Management System (EMS). Click the **Activate** tab to activate products from the list, and click the **Deactivate** tab to deactivate products from the list. For more information, see [activating / deactivating licenses](#).

Entitlement Id — enter the entitlement ID (sent to you via email) and click **Connect**. This enables you to activate licenses or deactivate / move licenses from one machine to another.

Remember Me — if you click this checkbox, your entitlement ID is saved, so that you can quickly reconnect to the EMS

Activate tab — lists the products you can activate

Deactivate tab — lists the products you can deactivate



Refresh icon — click this icon to refresh the product list in the table

Save Troubleshooting Data button — if you do not see the products you want in the list, Customer Care may ask you to click this button to generate a text file for troubleshooting purposes. If you need assistance, please [contact us](#). Note that this button only applies to the Activate tab.

Activate / Deactivate button — click this button to activate or deactivate products

How to...

These key procedures are essential to using Harmony Enterprise:

- [Connect to your data source](#)
- [Get well data into Harmony Enterprise](#)
- [Preview well data](#)
- [Analyze wells](#)
- [View results](#)
- [Export data](#)
- [Use workflows](#)
- [Link / unlink analyses](#)

Connect to your data source

Prior to connecting to your data source, you need to set up your database (SQL Server 2014 or later). This is a prerequisite for Harmony Enterprise.

When you launch Harmony Enterprise, the startup screen opens.

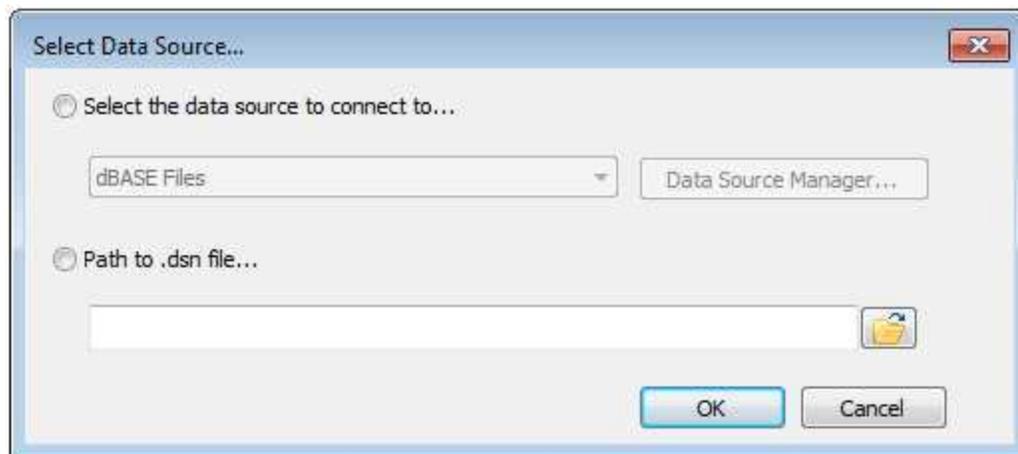


The top of the startup screen may include information about your computing environment (for example, AWS Cloud, AWS AppStream, Azure Cloud, or Citrix).

To connect to your data source:

1. Click **Connect to** and select from these options:

- **Harmony Enterprise Database** — for Harmony Enterprise (full version). Opens the Select Data Source dialog box.
 - **Existing .hldb file** — Browse to your existing local database file.
 - **New .hldb file** — Create an empty project to bring wells into.
2. In the Select Data Source dialog box, there are two ways to connect to an existing data source. Use option 1 or option 2.
- **Option 1:** configure your data source through the Data Source Manager, and then connect to that data source.
 - **Option 2:** if you have a .dsn file that points to a particular data source, you can connect using the .dsn file.



Connecting using the Data Source Manager

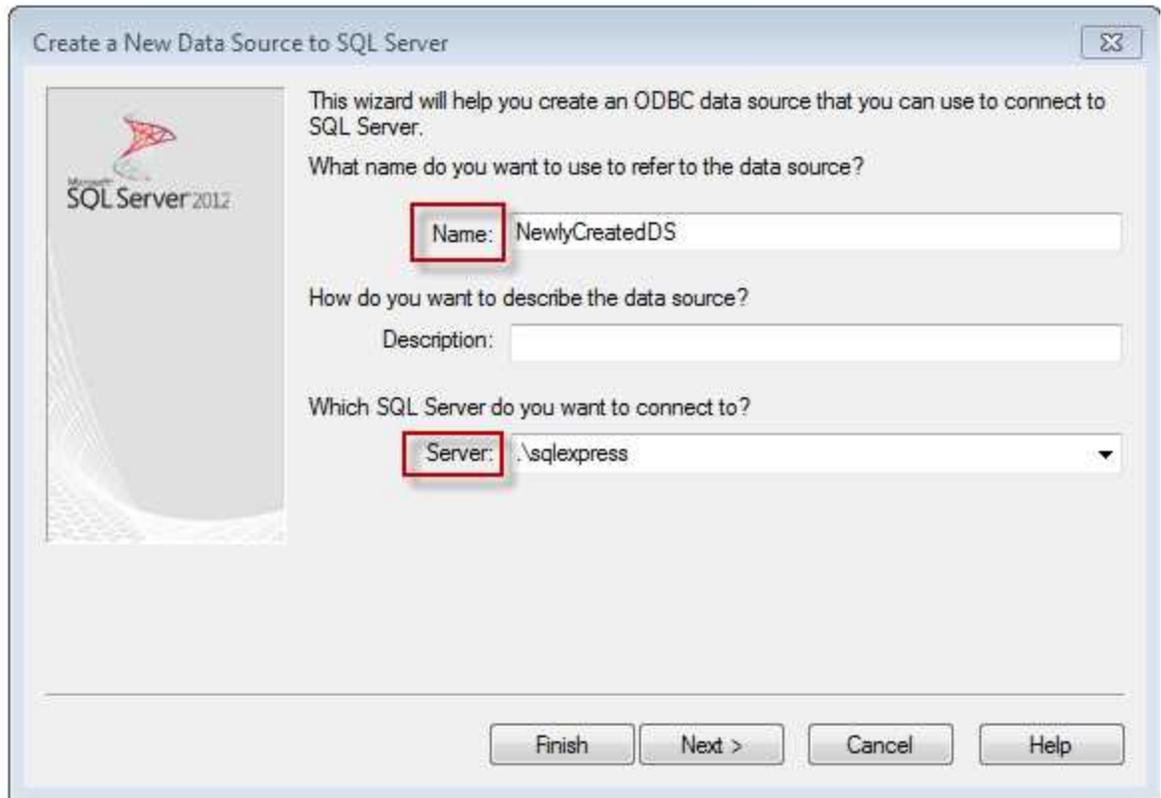
Harmony Enterprise requires a data source that uses the ODBC Driver 17 for SQL Server.

To connect to your data source using the Data Source Manager:

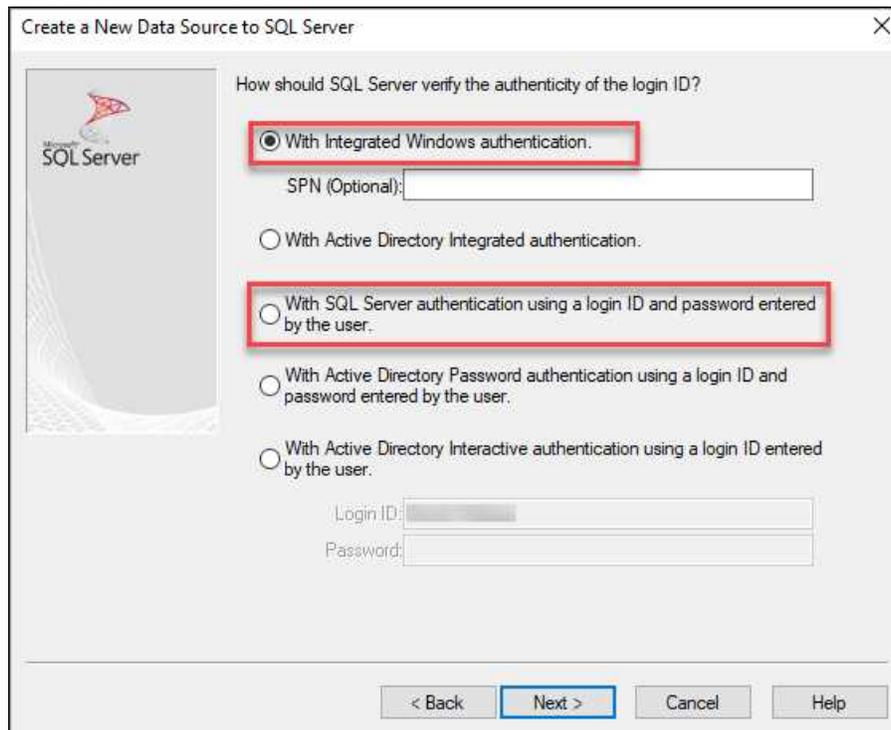
1. In the Select Data Source dialog box, click **Select the data source to connect to**.
2. To provide information on how to connect to your data source, click **Data Source Manager**. Select **ODBC Driver 17 for SQL Server** when creating your DSN.
The ODBC Data Source Administrator dialog box opens.
3. Click the **System DSN** tab (*not* the User DSN tab), and then click the **Add** button to create a new data source.
4. Select **ODBC Driver 17 for SQL Server** from the list of drivers and click **Finish**.

The Create a New Data Source to SQL Server dialog box opens.

5. Type a name for your data source, select the server you want to connect to from the drop-down list, and click **Next**.

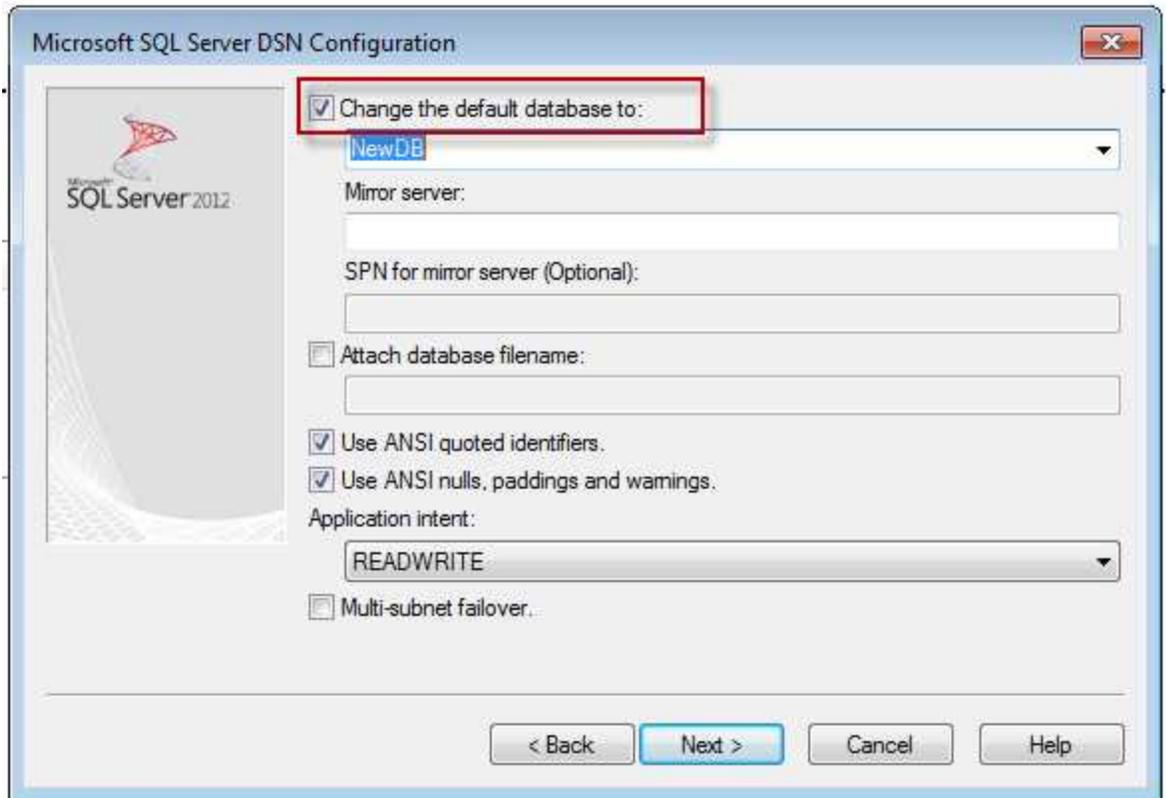


6. Select either Windows authentication or SQL Server authentication (the first or third options) and click **Next**.
(If you select an unsupported authentication mode, Harmony Enterprise cannot connect to your data source.)



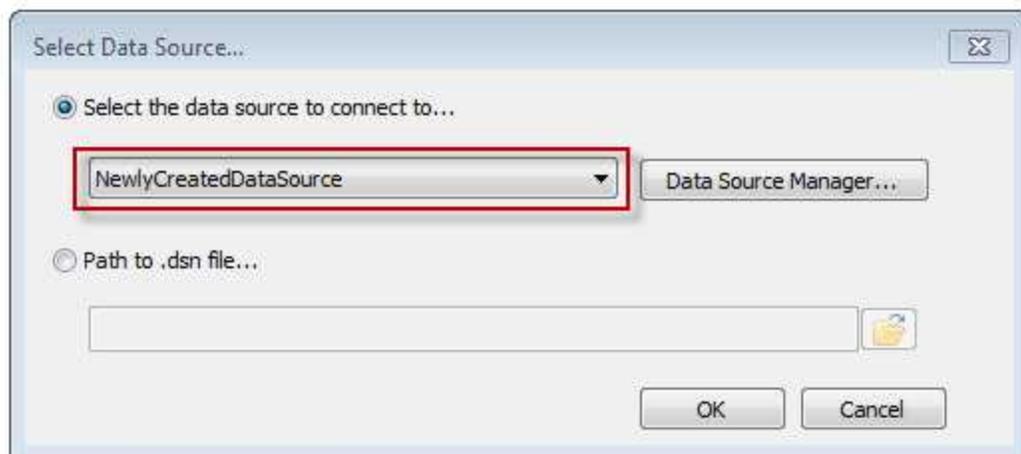
Tip: On Azure, Active Directory Integrated and Active Directory Password are also valid authentication options in setting up the DSN.

7. Select the database you want to connect to from the drop-down list, and click **Next**.



8. Click **Finish**. Close the ODBC Data Source Administrator dialog box.

9. Select your data source from the drop-down list and click **OK**.



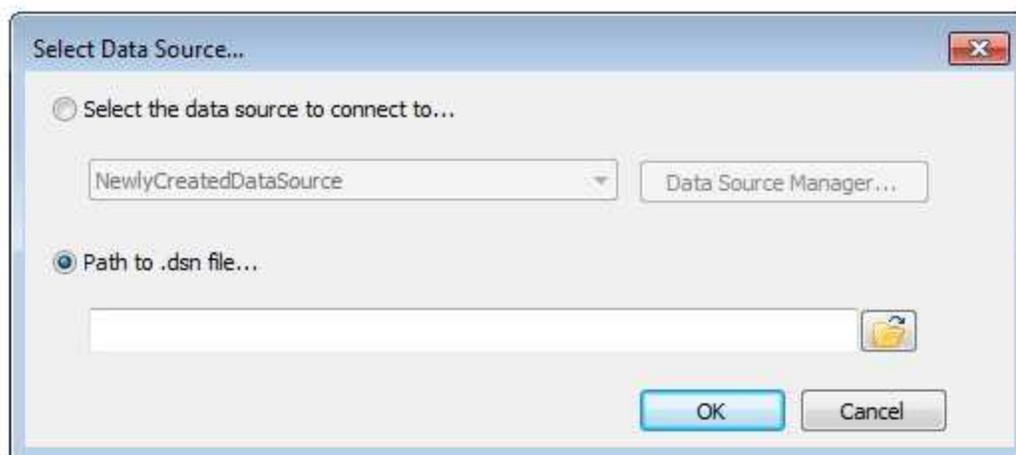
Your newly added data source is added to the drop-down list.

Connecting using a .dsn file

The .dsn file is a file that describes the data source, and it can be created by a database administrator.

To connect to your data source using a .dsn file:

1. In the Select Data Source dialog box, click **Path to .dsn file**.

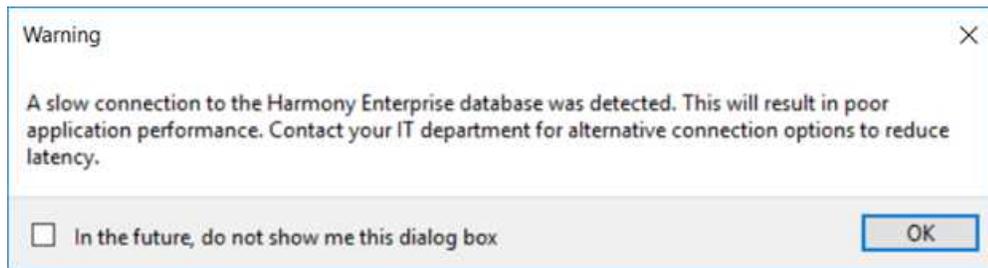


2. Type the full path to the .dsn file, or navigate to the file by clicking the **Browse** icon ().

Note: By default, clicking the Browse icon () opens the Documents folder. However, you can change this default location by setting a new default path with the **HARMONYDSN** environment variable.

Connecting to a remote database

We recommend that the server hosting your Harmony Enterprise database is co-located with the computers running Harmony Enterprise (for example, on your local office network). For optimal performance, this reduces the communication time between Harmony Enterprise and the database. When the connection to the database is slower than recommended, a warning about performance is displayed.



If you see this warning and find subsequent performance of Harmony Enterprise makes it difficult to complete your work, please work with your IT department to optimize your Harmony Enterprise deployment. If this is not possible, you may consider alternatives such as working on local .hldb files, or remoting into a computer with a better connection to the database.

You can continue to work on the database by dismissing the warning, but the warning is displayed or dismissed for each Harmony Enterprise database. In addition, the warning is displayed in the Status Window, even after you have dismissed the message.

Get well data into Harmony Enterprise

We recommend that you review your updating data settings prior to importing from Harmony. If you are importing into a Harmony Enterprise project where you expect to have duplicate wells (for the purpose of merging data), see updating existing wells.

To get well data into Harmony Enterprise, you can:

- import well data from a file
- import well data from a database
- import / update from IHS:
 - import from Enerdeq or information hub direct connect (IHDC)
 - import from Piper forecasts
 - import from PowerTools
 - import from WellTest
- import from an .hldb file

Note: If you are updating a well that has been locked by another user (for example, Well1 is in the process of being merged with an existing Well1), this merged well cannot be imported into Harmony Enterprise while there is a lock in place.

To verify that import settings are set as you want, see the Importing node in the [Options dialog box](#).

For more detailed examples on how importing and updating data is handled in Harmony Enterprise, we recommend the [Data Imports On Demand](#) course.

Harmony Enterprise example files

Harmony Enterprise example files are saved within this directory: C:\Users\Public\Public Documents\Harmony Shared\Harmony Enterprise 2022.2.

Tip: For hands-on practice with Harmony Enterprise, browse to the Examples folder (see above). In this directory, there are several different files that can be imported into your Harmony Enterprise project, including Merak (*.mer) and LocalDB (*.hldb) example files.

Troubleshooting .hldb file imports

If you see this error message, **Error, Failed to import new Entity: [WellName]. Problems in:Analysis**, troubleshoot as indicated below.

This error occurs when you are trying to import a well from an *.hldb file and the Analysis ID or Worksheet ID already exist for another well in your Harmony Enterprise database. This can happen when a well is imported and merged with an existing well, but in a later import, it is imported as a new well. In this case, the Well ID does not match, but the Analysis ID and Worksheet ID are identical. In order to resolve this conflict, either map the well to merge to the existing well with the matching Analysis ID, or delete the incoming analysis and worksheet with the conflict. The same Analysis ID and Worksheet ID cannot exist for multiple wells in Harmony Enterprise. For more information, see [general well linking logic](#) and [Harmony import logic](#).

Tip: When you import well data from .hldb files (local database files), if an analysis or worksheet already exists, it replaces the existing copy.

Import well data from a file

With Harmony Enterprise, you can import plain-content files, such as .csv, .txt, and .xlsx, along with the following file types:

File Type	File Extension	Sources
Merak Note that you can import injection tubing pressure and it is displayed as Tubing Pressure in the <u>Production editor</u> .	.mer	Geoscout
Dwight dmp2	.dp2, .dmp2	IHS Markit
Value Navigator (ValNav)	.vna	Accumap (IHS Markit Accumap can save files in a ValNav format. Note that Harmony Enterprise cannot import .xml files from ValNav.)
Lasser Data	.prn	Lasser Data
Aries	.axp	Aries (IHS Markit Accumap can save files in an Aries format.)
Geo Webworks	.mxd	Geo Webworks
298 98c	.98c	IHS Markit
Recorder	.rec	

Plain-content files

When you import plain-content files, you need to select one of Production, Attributes, or Static Pressure; you cannot import more than one at the same time.

To import well data from plain-content files (for example, .csv, .txt, .xls, etc.):

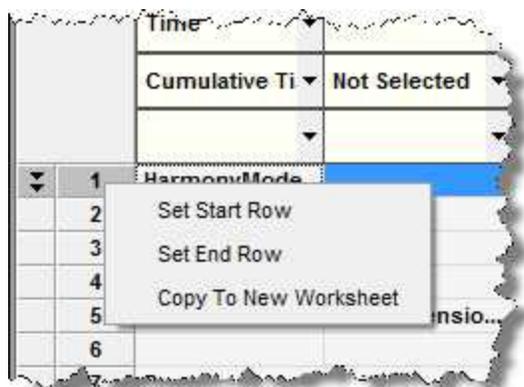
1. Click the **Import** icon () in the main toolbar and select **File**.
Or, you can click the **Import** menu and select **File**.
2. Browse to your file and click **Open**.
3. In the Import Data Type dialog box, select **Production**, **Attributes**, or **Static Pressure**.

Note: If you are importing data from the Production editor, production data is imported, and the Import Data dialog box opens after you click **Open** in step 2. Note that it is not possible to save an import template.

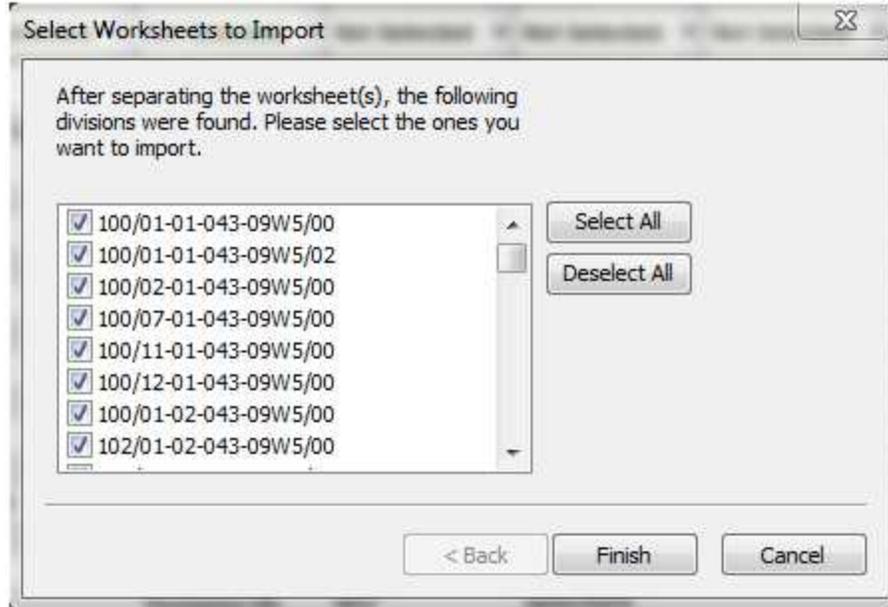
4. In the Import Data dialog box, assign column headers by clicking the drop-down arrows at the top of each column.
- You must assign a Time and Date Time column (when using Production data), and a Well Identifier and a second column (when using Attribute data).
 - If you select Production and a column is mapped to Well Identifier, Harmony Enterprise uses the name from the well identifier. This enables you to import one table or Excel worksheet containing multiple wells.
 - If you are importing from an Excel file (with or without multiple worksheets), Harmony Enterprise uses the worksheet name for the well name. This enables you to import multiple wells by separating them into different worksheets. (You can also use the Apply To button to copy the column mapping to all worksheets.)
 - If you are importing from a .csv or .txt file, and there is no column mapped to a well identifier, Harmony Enterprise uses the file name for the well name.

The Import Data utility assigns start and end rows to the dataset. The start row (the first entry populated in Harmony Enterprise's production or attributes table) is indicated by two arrows pointing down in the far left column. The end row (the last entry populated in Harmony Enterprise's production or attributes table) is indicated by two arrows pointing upwards in the far left column.

5. Verify that the correct rows are assigned as the start and end rows, and modify if necessary. To modify a row, right-click the row and select **Set Start Row** or **Set End Row**.



6. After you have assigned your column headings, click **OK**.
The Select Worksheets to Import dialog box opens.



7. Click the checkboxes for the entities you want to import, and click **Finish**.

Harmony Enterprise imports the well data. After the import process is complete, the new wells are listed in the Entity Viewer - Hierarchy pane. (If you imported the wells as a group, they are displayed as a new custom group in the Entity Viewer - Custom pane.)

8. Review your merge options in the Confirm Import Merge Options dialog box. To change your settings, click the **Options** icon () , which opens the Options dialog box. To proceed without make changes, click **OK**.

Other files

To import well data from the other supported file types:

1. Click the **Import** icon () in the main toolbar and select **File**.
Or, you can click the **Import** menu and select **File**.
2. Browse to your file and click **Open**.

Note: The import behavior for an incoming file, which contains well information about wells that are already in the database, is determined by the settings in the Options dialog box, under the Importing node.

Import well data from a database

You can import well production and reservoir data from your company's database into a Harmony Enterprise project. You can also import from an open database compliant (ODBC) database into Harmony Enterprise.

Harmony Enterprise uses the [Database Connection](#) wizard to facilitate importing well production and attributes, along with wellbore, fluid, and reservoir properties from your company's proprietary database into the Harmony Enterprise database.

Important: The Database Connection wizard reads data from your company's database, but does not write to it. Therefore, there is no danger that Harmony Enterprise can corrupt your database. However, you must ensure that the SQL or Windows login you use to connect has read access.

If you want to watch a video of the import database wizard, see [how to import data from a database](#) (opens The Learning Center in a new window). Note that you need to create an account in order to access content on The Learning Center.

To import well and production data from your database:

1. Click the **Import** icon () in the main toolbar and select **Database Connection**.
The Import Database Wizard opens.
2. In the Import Database - Harmony dialog box, read the welcome message and click **Next**.
3. In the Specify Connection Settings dialog box:
 - to create a new database connection, click **New Connection**.
 - to edit an existing database connection, select the connection, then click **Edit**.
 - to use an existing connection, select the connection, then click **Next**. Proceed to [step 9](#).
 - to delete an existing connection, select the connection, then click **Delete, Yes**.
 - to copy an existing connection, select the connection, then click **Duplicate**. This copies the existing database mappings in a connection to a new connection.
 - *(not applicable to SE licenses)* review your scheduled well updates (daily, weekly, or monthly). For more information, see [scheduling well updates](#).
4. In the [Set Up Connection Settings](#) dialog box, type / edit your connection name.

Your connection name, data source, connection credentials, and schema are saved for this database connection and can be used by others. Your user name and password are saved on a per-user basis.

Click **Access File** and browse to your Microsoft Access database (.mdb, .accdb files). Or, click **Data Sources** and select your data source from the drop-down list, or click **Add New**.

5. In the Specify Mapping dialog box (only applies to new database connections), select your initial mapping configuration (that is, Aries, IHS Views, Custom Mapping, Legacy Schema Mapping); click **Next**.

- **Aries** — We have provided a mapping based on the standard tables and columns available in an Aries database. Mapping is pre-configured for the default Aries data model.
- **IHS Markit Views** — If your DBA or other database support has already created a view in your database to map its content to Harmony Enterprise, select this option. Mapping comes from the SQL views or queries built within the data source.
- **Custom Mapping** — You can manually map the tables and columns in your database to recognized Harmony Enterprise data in the next part of the wizard.
- **FieldDIRECT** — We have provided a mapping based on the standard tables and columns available in a FieldDIRECT database. Mapping is pre-configured for the default FieldDIRECT data model.

6. In the Assign Mapping dialog box, set your initial mapping, or resolve any errors in the existing mapping as follows:

- a. In the left pane, tables are mapped by clicking the **Client Tables/Views (source)** cell. If you select a blank value, the table is not populated.
- b. In the left pane, select a table under Harmony Enterprise Views (destination). This populates the right pane with mapped columns for the selected table. In the right pane, select a cell under Client Column Name. This displays a drop-down list of available columns from the database you are importing.

Note: For well information, you can assign a field to more than one column. The Production History table does not have to be mapped. To download the View Definitions, see the Excel file.

7. To set your units, first resolve any errors in the right pane by clicking the **Client Column Name** cell, and selecting from the drop-down list. Then, click the **Units** cell, and select from the drop-down list. Click **Next**. (Errors are displayed in red text and warnings are displayed in orange text.)

Your source tables, source columns, and unit mappings are saved for this database connection, and are available for any user who connects to this source through the same Harmony Enterprise database.

8. In the Well Linking Criteria dialog box, select the attributes you want to use for linking wells; then click **Next**.

Note: The attributes you select for linking are saved for the current database connection only.

If there is no data in any of the columns you selected for well linking, the Entity Header Data Valuation dialog box opens, and it lists the columns with no data. You can change your mapping, change your well linking, or import anyway.

9. In the Set Up Filters dialog box, click **Add** to create a filter to restrict which wells are imported. If you do not enter any filters and click **Next**, all wells in the data source can be viewed and imported.

10. To create a filter, click **Add**. In the Filter a Column dialog box, select your filter from the **Filter Column** drop-down list, and then type / paste your values (lowercase or uppercase — filtering is case *insensitive*), or select from the checkboxes. Click **OK**; then click **Next**.

The validation of your filtering values is handled in the next step of the wizard, and your filters are saved for your database connection (not shared with others).

11. In the Select Wells to Import dialog box, a tree structure can be created to view available wells. To build a tree structure, click the **Tree Hierarchy** icon () and select attributes.

By default, all wells are selected. To exclude wells from import, click the checkboxes to deselect them. To see a preview of the production data, click the well's *name*. Click **Next**.

The wells you selected for import are saved for your database connection.

Note: When importing data with an irregular frequency (for example, WellTest data or synthetic data with a logarithmic time track), or all shut-in periods reported, click the **Continuous Time Track** checkbox. For more information, see [continuous time track](#).

12. In the Select Analyses to Import dialog box, select the decline curves you want to import. Click **Next**.

13. In the Import Options dialog box, options are displayed for updating the data of existing wells, auto-calculating sandface pressures, reducing data, and scheduling well updates. To override the global settings on a one-time basis, select your data options from the drop-down lists. For more information on these options, see updating data (set in the Options dialog box). To automatically import data, see scheduling well updates.

14. Click **Import** (or **Finish** in the case of scheduled imports).

15. Review your merge options in the Confirm Import Merge Options dialog box. To change your settings, click the **Options** icon () , which opens the Options dialog box. To proceed without make changes, click **OK**.

The database wizard remembers your last database connection, and it is automatically selected the next time you run the wizard.

Import / update from Enerdeq or IHDC

When sourcing data from Enerdeq using the file formats and the Direct Connection in Harmony Enterprise, you may encounter inconsistencies in fluid reporting. The result can be a duplication of data in the oil and condensate production for your wells, or a switch during the course of the production history from oil to condensate, or vice versa. Use the setting in the IHS Enerdeq Direct Connection to set fluids to import either as only oil, or only condensate. This can be combined with the Discard and Replace | Updating Data option to resolve any existing inconsistencies in your oil and condensate production data. The Merge options are not recommended to fix existing data in this case, as it can result in duplicates in oil and condensate during the same time period.

You can import / update data well production data and directional survey data from IHS:

- Enerdeq (opens the Enerdeq web page in a new window) provides access to US well and lease production data.
- The Canadian Hub or IHDC (Information Hub Direct Connect) provides access to Canadian well production data. Note that wells must have DLS or NTS naming.

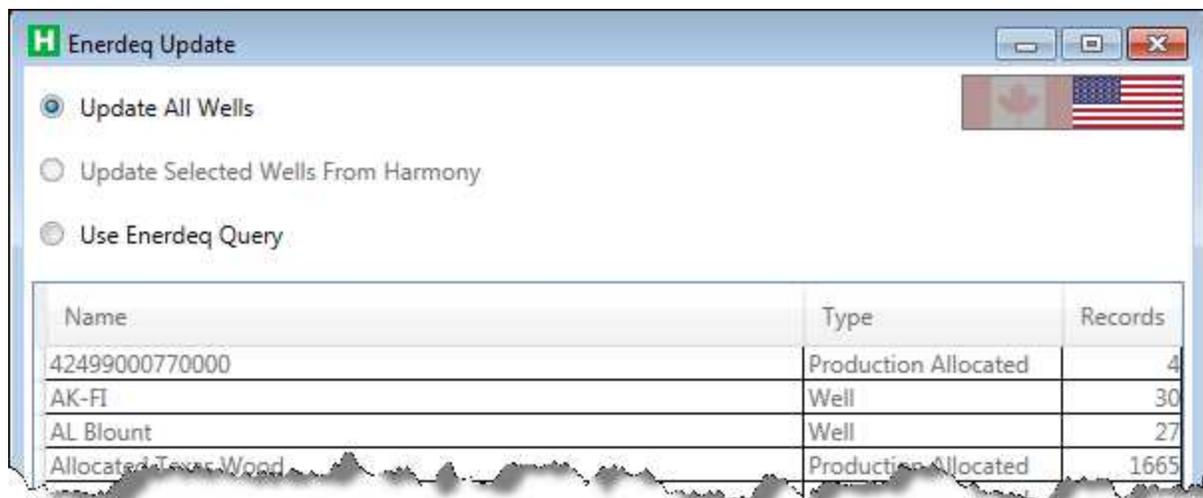
To import or update from IHS:

1. Click the **Import** icon () in the main toolbar and select **Enerdeq / IHDC**.
2. Select IHS Enerdeq (**US**) or IHDC (**Canada**).

Your options vary depending on your country.

3. Enter your IHS Enerdeq or IHDC credentials.

The dialog box options are now enabled.



4. To update your wells from Enerdeq, click **Update All Wells**.

If you have multiple wells that are mapped to existing wells, the [Link Imported Wells to Existing Wells dialog box](#) opens.

5. If you selected wells in Harmony Enterprise before selecting **From Enerdeq / IHDC**, the Update Select Wells from Harmony option is enabled. Click **Update**.

The wells in Enerdeq are updated with your Harmony Enterprise data.

6. (US only) To import wells / production data from [API](#) numbers obtained by running an Enerdeq query, click **Use Enerdeq Query** and then click **Import**.

Or, double-click a row in the table.

7. Review your merge options in the Confirm Import Merge Options dialog box. To

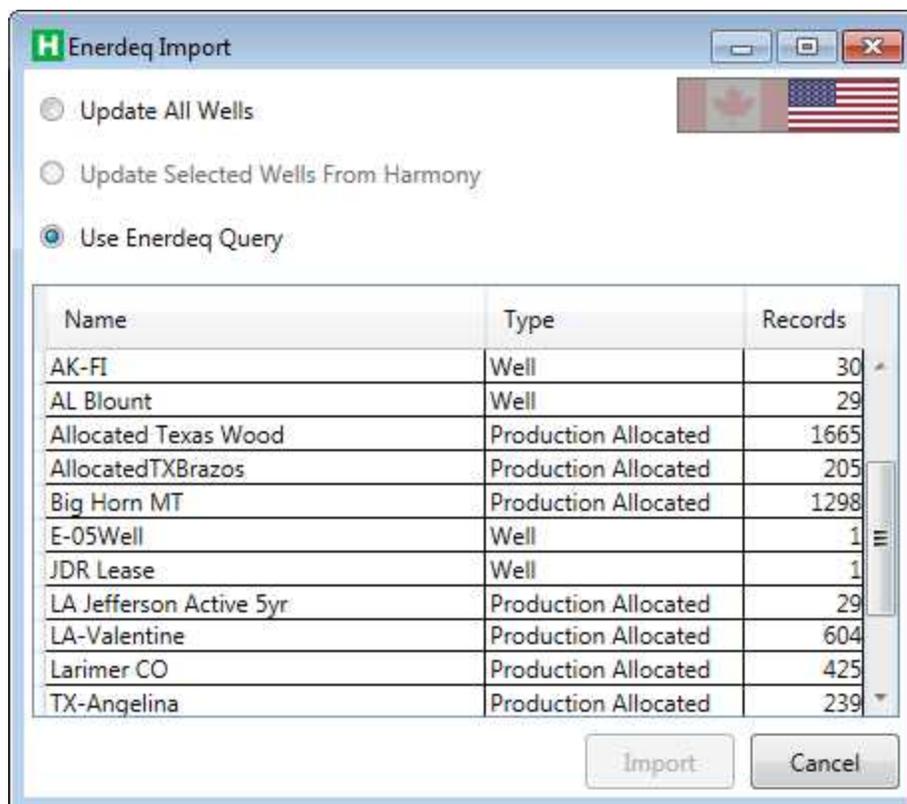
change your settings, click the **Options** icon () , which opens the [Options dialog box](#). To proceed without make changes, click **OK**.

Enerdeq queries (US only)

In the Enerdeq Update dialog box (see above), selecting the **Use Enerdeq Query** option displays queries currently saved in your Enerdeq account. Note that unallocated production is not imported — unallocated queries are not displayed in the table.

This table shows the query type (allocated production or well), and lists the number of records that the query currently returns. (The table can be sorted by clicking the column headers.) If you

have set your import option to combine records with the same API (some wells have multiple production IDs), the number of wells imported to Harmony may differ from the number of records listed in the table.



Import from Piper forecasts

If you have forecasts in Piper®, you can import them into Harmony Enterprise, but the wells in Piper *must* have originated from Harmony Enterprise. This is because Piper uses a unique Harmony identifier to match Piper forecasts to the wells in Harmony Enterprise.

To import from Piper:

1. Click the **Import** menu and select Piper Forecasts.

Or, click the **Import** icon () in the main toolbar and select Piper Forecasts.

2. Review your merge options in the Confirm Import Merge Options dialog box. To change your settings, click the **Options** icon (), which opens the Options dialog box. To proceed without make changes, click **OK**.

Note: Incoming Piper wells are merged with existing wells in Harmony Enterprise. We do not use the [Updating Data | Analysis Data](#) settings in the Options dialog box. Instead, when wells exist in the Piper .fdb file, but do not exist in the Harmony Enterprise project, they are not added. For wells that exist, incoming forecasts are always added, and added as new analyses (existing analyses are not modified).

Import from PowerTools

You can import PowerTools data into Harmony Enterprise if you have these files:

- Access database file (.mdb) — this Microsoft database file must be from PowerTools 9.3 or later.
- (optional) cache folder (with .98c files) — each .98c file represents a single well's data.

Note: Decline analyses in PowerTools are imported with a maximum b value of five. In addition, imported files do not include economics or FieldDIRECT data.

To import from PowerTools:

1. Open the [Options dialog box](#), and then navigate to **Importing, Updating Data, Analysis Data** to select how you want to import any existing analyses from PowerTools. Close the Options dialog box.
2. Click the **Import** menu and select **PowerTools**.

Or, in the main toolbar, click the **Import** icon () and select **PowerTools** ().

The PowerTools File Import dialog box opens.

3. Browse to your .mdb PowerTools file.
4. (Optional) Browse to the folder where your .98c cache files reside.

Note: If your cache files are stored elsewhere, you can import this data later via an Enerdeq update. Make sure that your .98c files match your .mdb file, so that the production data is synchronized.

5. Click the **Import** button.

If there are no .98c files that match the .mdb file, the .mdb file imports its data, and then a dialog box opens stating that none of the .98c files were imported.

6. Review your merge options in the Confirm Import Merge Options dialog box. To change your settings, click the **Options** icon () , which opens the Options dialog box. To proceed without make changes, click **OK**.

Note: If you have missing static pressures in your PowerTools project (Access data-base file) or .98c file, your material balance is not brought over.

Import from WellTest

WellTest files can be imported to Harmony Enterprise. You can transfer the following data:

- Production Editor data
- Properties data — excluding advanced properties, such as relative permeability and custom property tables.
- Wellbore Parameters — WellTest has one wellbore and uses the Physical Wellbore / Initial configuration in Harmony Enterprise.
- Analytical and Numerical (Hybrid) models — only these models are supported. (CBM and Numerical models are not supported.)

Note: WellTest version 2012v3 and later is supported by Harmony Enterprise.

To import from WellTest:

1. Click the **Import** menu and select **WellTest** () .
2. Review your merge options in the Confirm Import Merge Options dialog box. To change your settings, click the **Options** icon () , which opens the Options dialog box. To proceed without make changes, click **OK**.

Note: We do not use the Updating Data | Analysis Data settings in the Options dialog box. Instead, incoming analyses are always added, and added as new analyses (existing analyses are not modified).

Import from an .hldb file

In place of SQL Server databases, Harmony Enterprise provides an option to create or export to an .hldb file. These .hldb files can be imported into Harmony Enterprise SQL databases, or other .hldb files in order to merge or replace your work.

Whether or not information is overwritten, appended, or merged into the existing database, is dictated by the [Options dialog box](#). Wells and groups that were originally extracted from Harmony Enterprise have an ID that requires them to be merged back to the original. Analyses that have been modified from the original are overwritten, and new analyses are appended.

Note: With an SE license, you cannot import entities from an .hldb file.

The following items are not imported:

- GIS layers (shape, image, bubble, annotations, flags)
- Comparison plots
- Classified analyses not associated with the active reference date
- Report sets
- Monitor results

Since options, templates, and workflows are user-specific and saved on your workstation, these items are not imported.

To import from an .hldb file:

1. Click the **Import** icon () and select **.hldb file**.
2. Browse to your .hldb file and click **Open**.
Your imported entities are brought into your existing database from the entities in the .hldb file.
3. Review your merge options in the Confirm Import Merge Options dialog box. To change your settings, click the **Options** icon () , which opens the [Options dialog box](#). To proceed without make changes, click **OK**.

Note: We do not use the [Updating Data | Analysis Data](#) settings in the Options dialog box. Instead, when you import from .hldb files (local database files), if an analysis or worksheet already exists, it replaces the existing copy.

Custom groups

If you import an .hldb file with a custom group that has the same name and ID as one found in the database, the custom group is merged in the database.

If you import an .hldb file with a custom group that has the same name but a different ID from one in the database, a new custom group is created with a filename appended by a numeric (for example, <custom_group>(1), <custom_group>(2), etc).

Preview well data

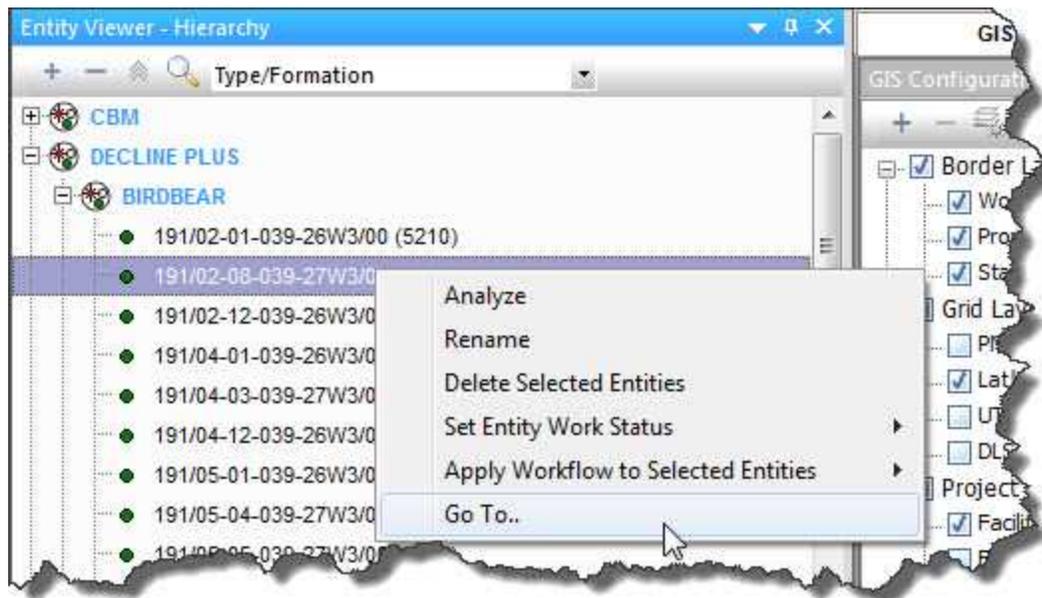
When you click various tabs, a different subset of information is displayed in the main pane for the selections in the Entity Viewer (Hierarchy or Custom). The geographic information system (GIS) tab displays the location of the entities on a world map, if the location attribute fields are populated, while the Attributes tab displays the meta-data associated with the selected entities. Datasets associated with the selected entities can be viewed from the Diagnostics tab.

The following examples describe how you can preview wells, or groups of wells, on these tabs: GIS, Attributes, and Diagnostics.

GIS well preview

To preview a well in the GIS tab:

1. Select the well in the Entity Viewer (Hierarchy or Custom).
2. Right-click the well and select **Go to**.



The GIS zooms in towards the selected well and highlights it.

Note: Entities that do not have values recorded for their location attributes are not displayed in the GIS.

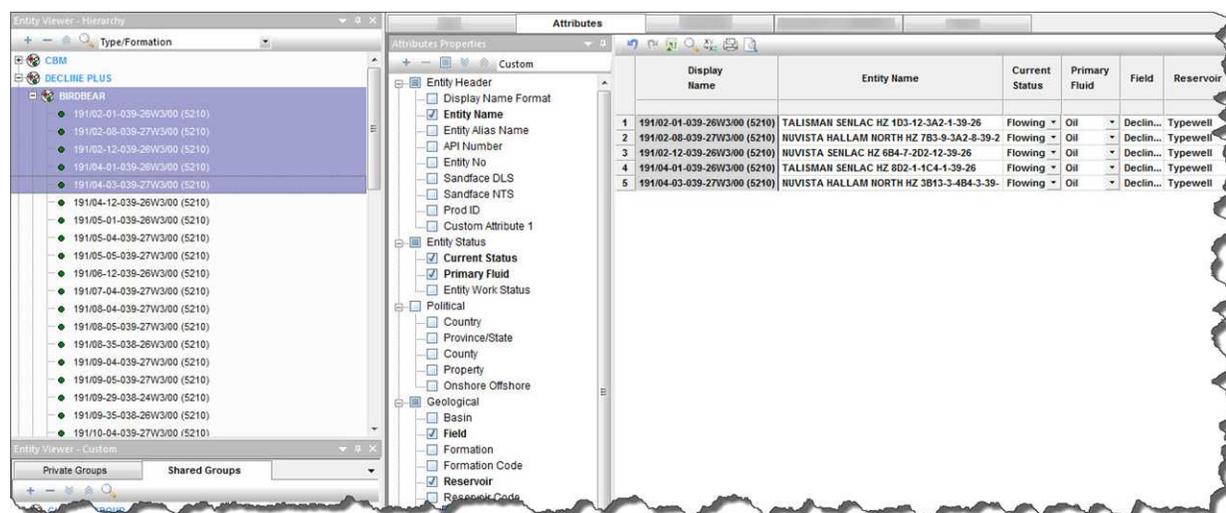
Attributes well preview

To preview well attributes:

1. Select the well (or multiple wells) in the Entity Viewer (Hierarchy or Custom).
2. Click the **Attributes** tab.

By default, the auto template displays the following attributes: Display name, Entity Name, API Number, Entity No, Current Status, Primary Fluid, Country, Province / State, Field, Reservoir, and Unit.

3. Select the attributes you want to view from the Attributes Properties tree structure by clicking the checkboxes next to the attribute. (Selecting a category displays all of the attributes in the category.)



Note: Attributes are not displayed for groups; therefore, a selection that includes both groups and wells only displays the well attribute data.

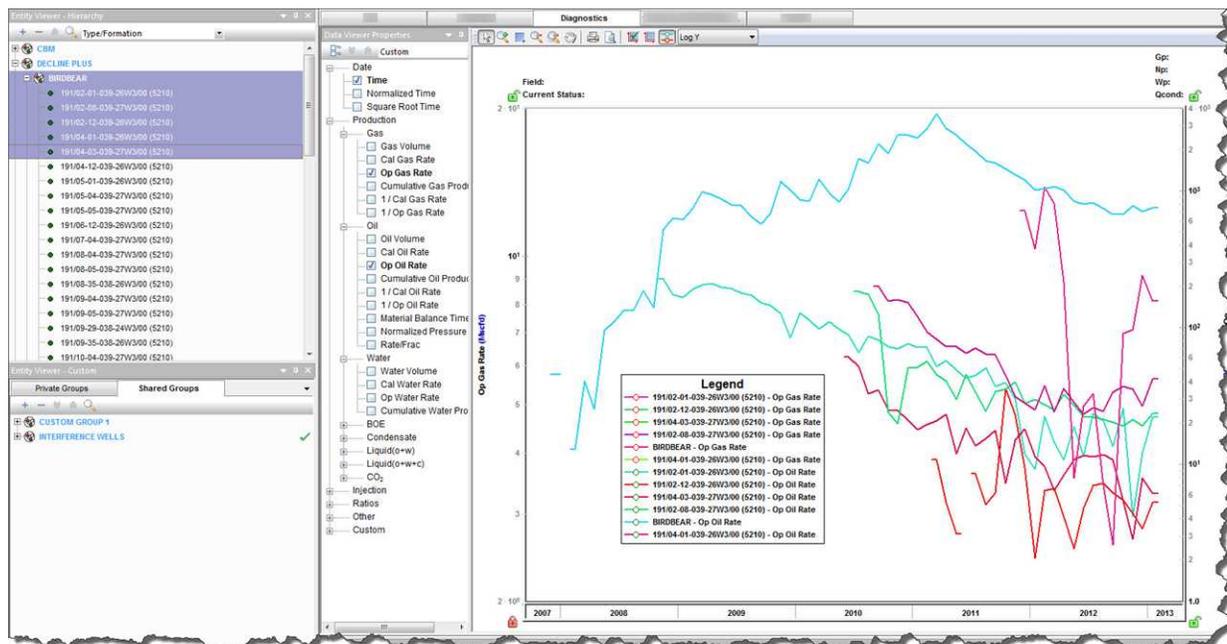
Diagnostics well preview

To preview well production data:

1. Select the wells and/or groups in the Entity Viewer (Hierarchy or Custom).
2. Click the **Diagnostics** tab.

By default, the auto template selects the gas, oil, and water-rate datasets, if they are populated, and plots them.

3. Select the datasets you want to view in the Data Viewer Properties tree structure by clicking the checkboxes next to the dataset.



Note: Selecting a group displays the aggregate production data of the constituent wells in the group, while selecting multiple wells displays the production data of the individual wells.

Analyze well data

In order to analyze well data, you need to select an entity (for example, a well, scenario, or group), and then click the Analysis tab.

Selecting an entity for analysis

To select an entity for analysis, follow the steps in the table below.

Location	Method of Selecting	Notes
Entity Viewer (Hierarchy or Custom)	<ul style="list-style-type: none"> Click an entity (well or group) name. Click the Analysis tab. 	You can select any entity that exists in the viewer.

Location	Method of Selecting	Notes
GIS map	<ul style="list-style-type: none"> ▪ Click an entity on the map. ▪ Click the Analysis tab. 	You can only select a well from the GIS map.
Analysis tab	<ul style="list-style-type: none"> ▪ Click the Analysis tab ▪ Click an entity in the Entity Viewer (Hierarchy or Custom) 	You can select any entity that exists in the viewer.

After you have selected an entity for analysis, that entity is locked until you select another entity. In other words, the lock is released when you click another entity. If another user tries to open the same entity for analysis while the lock is in place, a message is displayed in the main pane and the Status Window. There is no way to force the release of the well, but the username with the locked well is displayed in the Status Window.

Note: The editors are also locked when you are performing an analysis.

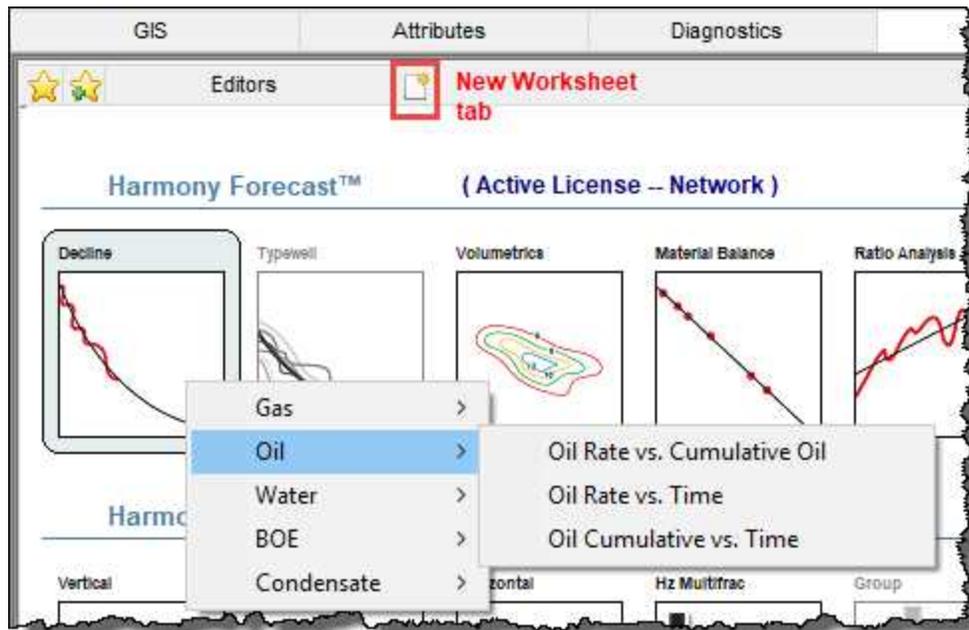
Analyzing an entity

To analyze an entity:

1. Select an entity for analysis.

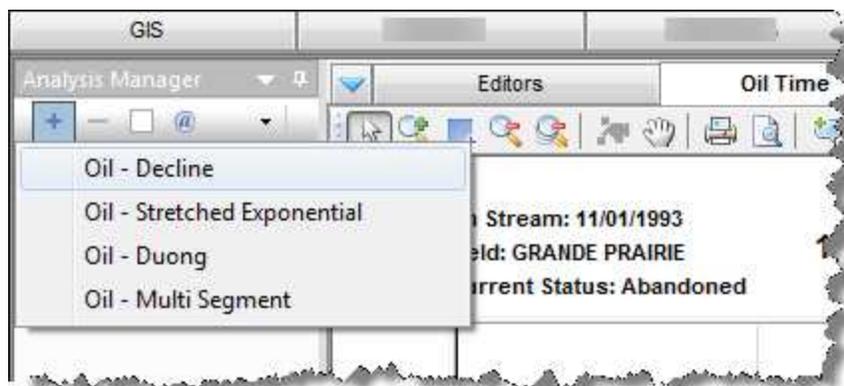
The New Worksheet tab opens. Or, if one or more worksheets exist, one of these opens.

2. Add a gas decline worksheet. (You must add a worksheet before you can analyze an entity.) Click a worksheet image, and if applicable, select a worksheet type from the submenu.



The worksheet is added.

3. Add an analysis by clicking the + icon on the Analysis Manager toolbar and selecting an analysis type. A decline analysis is shown as an example.



The analysis is added to your worksheet. For more information on analyses, see [analysis types](#).

View results

After you perform an analysis, you can view the results of multiple analyses from one or more wells on the Results tab. These results can be viewed in a tabular format using the grid view, or

graphically in a cross plot using the plot view. Well attributes can also be displayed in conjunction with the analysis results in both views.

Grid view

To view your results in grid view:

1. Select one or more wells or groups from the Entity Viewer (Hierarchy or Custom pane), or the GIS tab, and then click the **Results** tab.
2. Click the **Grid View** navigation button at the bottom of the Result Viewer pane.
3. Select the parameters you want to display by selecting the appropriate checkboxes in the Results Viewer pane (tree structure).

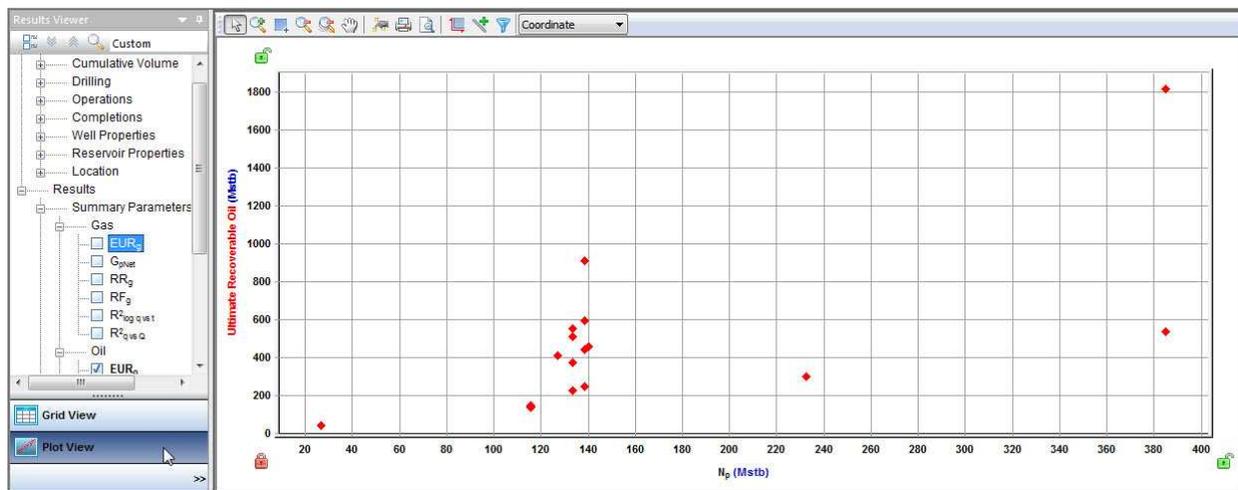
	Display Name	Analysis Name	Summary Parameters			Attributes		
			Oil			Cumulative Volume	Location	
			EUR _o	N _{pNet}	RR _o		Lat _{wh}	Long _{wh}
			Mstb	Mstb	Mstb	Mstb		
1	CNRL WORSLEY 10-33-87-7	PDP - 2009/05/31	246.425	140.499	105.925	138.388	56.5905300	-119.0497200
2	CNRL WORSLEY 10-33-87-7	PPDP - 2009/05/31	439.309	140.499	298.809	138.388	56.5905300	-119.0497200
3	CNRL WORSLEY 10-33-87-7	PPDP - 2009/05/31	912.294	140.499	771.795	138.388	56.5905300	-119.0497200
4	CNRL WORSLEY 10-33-87-7	UnclassifiedRateCum	592.128	138.388	453.740	138.388	56.5905300	-119.0497200
5	CNRL WORSLEY 12-33-87-7	PDP - 2009/05/31	132.384	117.297	15.087	115.631	56.5887400	-119.0595800
6	CNRL WORSLEY 12-33-87-7	PPDP - 2009/05/31	137.799	117.297	20.503	115.631	56.5887400	-119.0595800
7	CNRL WORSLEY 12-33-87-7	PPDP - 2009/05/31	144.105	117.297	26.808	115.631	56.5887400	-119.0595800
8	CNRL WORSLEY 12-33-87-7	UnclassifiedRateCum	139.617	115.631	23.986	115.631	56.5887400	-119.0595800
9	CNRL WORSLEY 14-33-87-7	PDP - 2009/05/31	223.245	134.718	88.527	133.462	56.5923100	-119.0539100
10	CNRL WORSLEY 14-33-87-7	PPDP - 2009/05/31	369.723	134.718	235.005	133.462	56.5923100	-119.0539100
11	CNRL WORSLEY 14-33-87-7	PPDP - 2009/05/31	511.951	134.718	377.234	133.462	56.5923100	-119.0539100
12	CNRL WORSLEY 14-33-87-7	UnclassifiedRateCum	551.897	133.462	418.435	133.462	56.5923100	-119.0539100
13	CNRL WORSLEY 16-33-87-7	Analysis 1	534.154	384.980	149.174	384.980	56.5926000	-119.0425700
14	CNRL WORSLEY 16-33-87-7	UnclassifiedRateCum	1816.575	384.980	1431.594	384.980	56.5926000	-119.0425700
15	OLY ET AL WORSLEY 2-4-88-7	UnclassifiedRateCum	40.585	26.656	13.930	26.656	56.5976700	-119.0449000
16	Well 1	UnclassifiedRateCum	455.172	140.362	314.810	140.362	56.5868866	-119.0560572
17	Well 2	UnclassifiedRateCum	297.404	232.398	65.006	232.398	56.5849815	-119.0637058
18	Well 3	UnclassifiedRateCum	410.587	127.255	283.332	127.255	56.5958997	-119.0497417

Plot view

To view your results in plot view:

1. Select one or more wells or groups from the Entity Viewer (Hierarchy or Custom pane), or the GIS tab, and then click the **Results** tab.
2. Click the **Plot View** navigation button at the bottom of the Result Viewer pane.

3. Select the parameters you want to display by selecting the appropriate checkboxes in the Results Viewer pane (tree structure).
Or, you can drag-and-drop the parameters to the plot.



Export data

You can export these data types using an export wizard:

- [Production data](#)
- [Forecasts](#)
- [Decline parameters](#)

You can export wells and well-and-analysis pairs for:

- use in Piper[®] by using the [Piper Export wizard](#)
- [use in WellTest](#)

In addition, you can export the following:

- [Export to an .hldb file](#)
- [Export to Analytics Explorer](#)

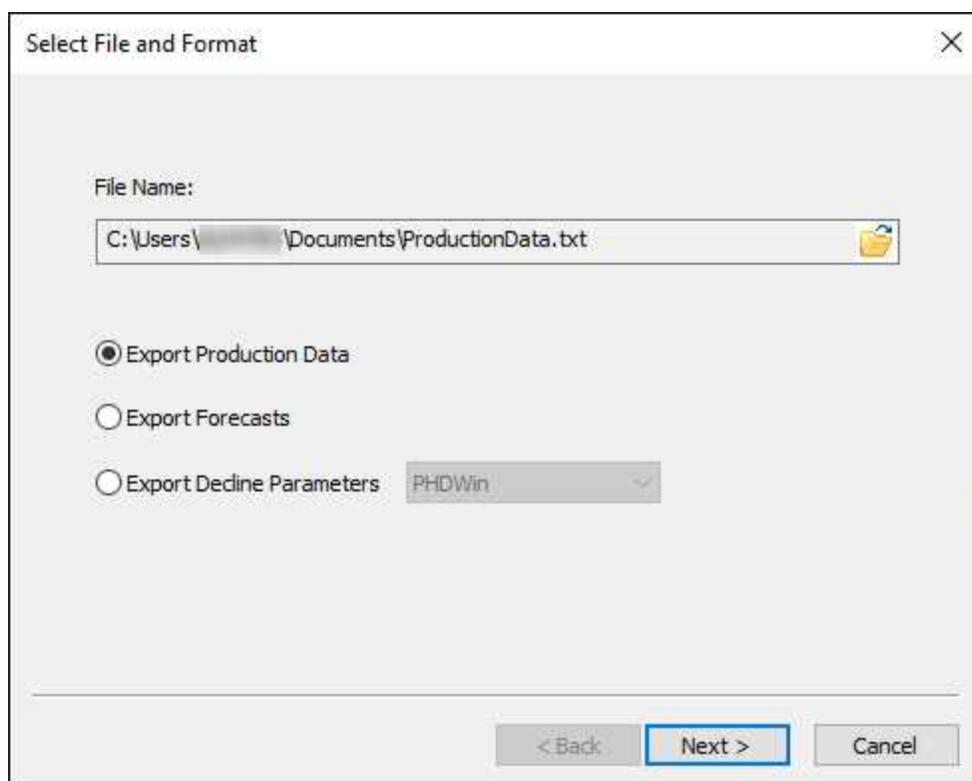
Export production data

Exporting production data includes all the datasets in the [Production editor](#).

To export production data:

1. Click the **Export** icon () in the main toolbar and select **Production Data, Forecasts, or Decline Analyses**.

The export wizard opens.



2. In the Select File and Format dialog box, browse to the location where your text file is to be saved. Click **Export Production Data** and then click **Next**.
3. In the Select Entities dialog box, select the entities you want to export from the three tabs: Hierarchy, Shared Groups, and Private Groups. Click **Next**. Note that you can search for entities by name by clicking the **Search** icon.
4. In the Select Output Data dialog box, click the checkboxes for the attributes and fluid rates / volumes you want to export. Click **Next**.
5. In the Export Preview dialog box, apply the sampling rate you want to export the data in. To re-sample the data to be daily, monthly, or yearly, click the **D**, **M**, or **Y** icons. To maintain the original sampling rate of the data, click the actual (**A**) icon.

6. Review your selections, and then click **Finish**. Note that the export can be customized as follows:

- The format for the date columns (and the units and precision for numeric columns) can be changed by right-clicking the green column headers.
- The order of the columns can be customized by dragging-and-dropping the column headers.

Note: Custom datasets are not included when you export your production data.

Export forecasts

These forecasts can be exported:

- Decline
- Multi-segment decline
- Water-oil ratio (WOR) total fluid forecast
- Oil cut total fluid forecast
- Ratio forecast
- Custom forecast
- Forecast consolidation
- Numerical model forecasts
- Analytical model forecasts
- Unconventional reservoir forecasts
- Typecurve forecasts

To export forecasts:

1. Click the **Export** icon () in the main toolbar and select **Production Data, Forecasts, or Decline Analyses**.

The export wizard opens.

2. In the Select File and Format dialog box, browse to the location where your text file is to be saved. Click **Export Forecasts** and click **Next**.

3. In the Select Entities dialog box, select the entities you want to export using any of the available tabs: Hierarchy, Shared Groups, and Private Groups (if applicable). Click **Next**. Note that you can search for entities by name by clicking the **Search** icon.
4. In the Select Analyses dialog box, click the checkboxes for the analyses (including consolidations) you want to export, and then click **Next**.
5. In the Select Attributes dialog box, click the checkboxes for the attributes and fluid rates / volumes you want to export. Clicking the **Include Historical Data** checkbox prefixes the historical production from the entity to each forecast until the forecast start date (this does not apply to declines from typewell worksheets). Click **Next**.
6. In the Export Preview dialog box, review your selections, and then click **Finish**. Note that the export can be customized as follows:
 - The units for numeric columns can be changed by right-clicking the green column headers.
 - The order of the columns can be customized by dragging-and-dropping the column headers.
 - The resolution can be changed to daily, monthly, or yearly by clicking the **D**, **M**, or **Y** icons in the toolbar.
 - This resolution change only applies to the exported forecast.
 - If historical data is included, that data is always exported at the original resolution (it is not resampled to D, M, or Y).

Note: Forecasts from Reservoir analyses are calculated based on the timesteps set in the Forecast tab for the analysis. While you can choose to export as daily, if the forecast is calculated at a lower resolution, it gives the same value for each day within the model's timesteps.

The wizard closes, and a message is displayed in the Status Window with the path to the file you exported.

Export decline parameters

These decline parameter formats can be exported:

- Aries
- Val Nav
- PHDWin
- MOSAIC

Note: You can set a classification for your data in the [Analysis Manager](#).

To export decline parameters:

1. Click the **Export** icon () in the main toolbar and select **Production Data, Forecasts, or Decline Analyses**.

The export wizard opens.

2. In the Select File and Format dialog box, browse to the location where your file is to be saved. Click **Export Decline Parameters** and select your export format, and then click **Next**.
 - **Aries** — exports gas, oil, water, and condensate decline analyses. This includes decline analyses at the entity, hierarchy, or custom-group level, and includes decline and multi-segment analyses. The output format is a .txt file. When exporting to Aries, the display name used for each well is based on the data available. If Propnum is populated, it is used; otherwise, API is used. If neither of these is available, the display name is used.
 - **Val Nav** — only exports reserve-classified gas and oil decline analyses. This includes decline analyses at the entity and hierarchy level, and includes decline and multi-segment analyses. The output format is an .xml file.
 - **PHDWin** — exports gas, oil, water, and condensate decline analyses. This includes decline analyses at the entity, hierarchy, or custom-group level, and includes decline and multi-segment analyses. The output format is a .csv file.
 - **MOSAIC** — exports decline and multi-segment decline analyses in a MOSAIC format. This includes decline analyses at the entity, hierarchy, or custom-group level, and exports decline parameters in a generic format to a .xlsx file. Files exported using this option can be imported to MOSAIC (version 2015.5 and later).

If you try to export a linked analysis containing any invalid analysis types, it does not export.

3. In the Select Entities dialog box, select the entities you want to export from the three tabs: Hierarchy, Shared Groups, and Private Groups. Click **Next**. Note that you can search for entities by name by clicking the **Search** icon.

4. In the Select Analyses dialog box, click the checkboxes for the analyses (including consolidations) you want to export, and then click **Next**.

The file is saved with a message in the Status Window and the wizard closes.

Export a file for use in Piper[®]

You can export wells for building and calibration purposes, and well-and-analysis pairs for forecasting purposes.

To export a .hmy2pip file from Harmony Enterprise to use in Piper:

1. Click the **Export** icon () in the main toolbar and select **To Piper**.
The Piper export wizard opens.
2. In the Welcome dialog box, read the message and click **Next**.
3. In the Piper Export | Export Type dialog box, click **Building and Calibration** or **Forecasting**. Note that you must calibrate your data prior to forecasting.

If you select **Building and Calibration**, the following data is exported: well locations, attributes, as well as rates and pressures on the effective / calibration date.

If you select **Forecasting**, analytical wells are exported with their paired analytical analysis / model. Each well is paired with an analysis.

4. Browse to the location where your .hmy2pip file is to be saved. Click **Next**
5. In the Piper Export | Select Entities dialog box, select the wells you want to export in one of the tabs (Hierarchy, Shared Groups, or Private Groups). Note that you do not see the Private Groups tab if you are using an .hldb file.
6. (For Building and Calibration) Click **Export**.
7. (For Forecasting) Click **Next**.
8. (For Forecasting) In the Piper Export | Analyses Selection dialog box, select the analyses you want to export. Click **Next**.
9. (For Forecasting) If more than one analysis has been paired with a well, the Piper Export | Well-Analysis Pairing Conflicts dialog box opens.
For each well with a conflict, select an analysis or exclude the well from the export by selecting from the drop-down list. Click **Next**.

10. (For Forecasting) In the Piper Export | Preview dialog box, review your well-and-analysis pairings. If no corrections are needed, click **Export**.

If you need to make corrections, click **Back** to return to the previous dialog box.

The Piper Export | Summary dialog box opens, which outlines what happened with the export. If you want additional information, click the **View export log file** link. For more information, see the [example export logs](#).

Piper requires tubing data, so if a well in Harmony Enterprise is using a casing flow path, when the well is exported, the casing internal diameter is saved into the tubing internal diameter field in the .hmy2pip file. When imported into Piper, the well has a tubing flow path, where the tubing internal diameter is equal to the casing internal diameter in the Harmony project.

Note: Gas lift data requirements in Harmony Enterprise are different than gas lift requirements in Piper. If a well in Harmony Enterprise has a Gas Lift flow path, when imported into Piper, the well has a tubing flow path. You must set the gas lift flow path with required gas lift data inputs in Piper's Wellbore Descriptions editor. For more information, see [modeling wellbores](#) (opens the Piper help in a new window).

11. Click **Done**.

Important: If sandface pressures are not calculated in Harmony Enterprise, they are calculated for the Piper export. These calculations are not written to the Harmony Enterprise project database.

Export to WellTest

Only [Analytical](#) and [Numerical](#) models are exported. You can select groups, and all child wells are exported. Note that the following items are not exported:

- [Scenarios](#)
- Prior production with production data
- Numerical models without fractures

To export a .hmexp file from Harmony Enterprise to use in WellTest:

1. Select the wells you want to export in the Entity Viewer - Hierarchy or Custom.
2. Click the **Export** icon () in the main toolbar and select **To WellTest**.
3. Browse to the location where you want to save your .hmexp file.

Your files are ready to use in WellTest.

Export to an .hldb file

If you want to perform some work outside of the database (for example, if you want to test some analyses without modifying the existing work in your current project database), then you can export wells, scenarios, or groups into a separate project. This work can remain in a separate project, or you can import this data back into the source project later. For more information, see [import from an .hldb file](#).

Exporting entities from a Harmony Enterprise database is a process that creates an .hldb file from the entities using Microsoft SQL LocalDB. You can connect to the .hldb file with Harmony Enterprise, as long as the LocalDB is installed on your computer. Or, you can import the .hldb file into a Harmony Enterprise SQL database (not applicable to SE licenses). You can transfer wells from one database to another, work on a subset of wells offline, or send your work to technical support.

Harmony Enterprise .hldb files only support Microsoft SQL Server Express LocalDB. For your convenience, the supported version of LocalDB is included in the Harmony Enterprise installation.

Keep these items in mind:

- Reference dates and the classified analyses associated with them are exported. The current user's active reference date is set as an active reference date in the exported .hldb.
- Private custom groups are not supported for .hldb projects. Therefore, exported private groups become shared custom groups in the exported .hldb.
- The active hierarchy structure is exported. The current user's active hierarchy structure is exported to the .hldb.

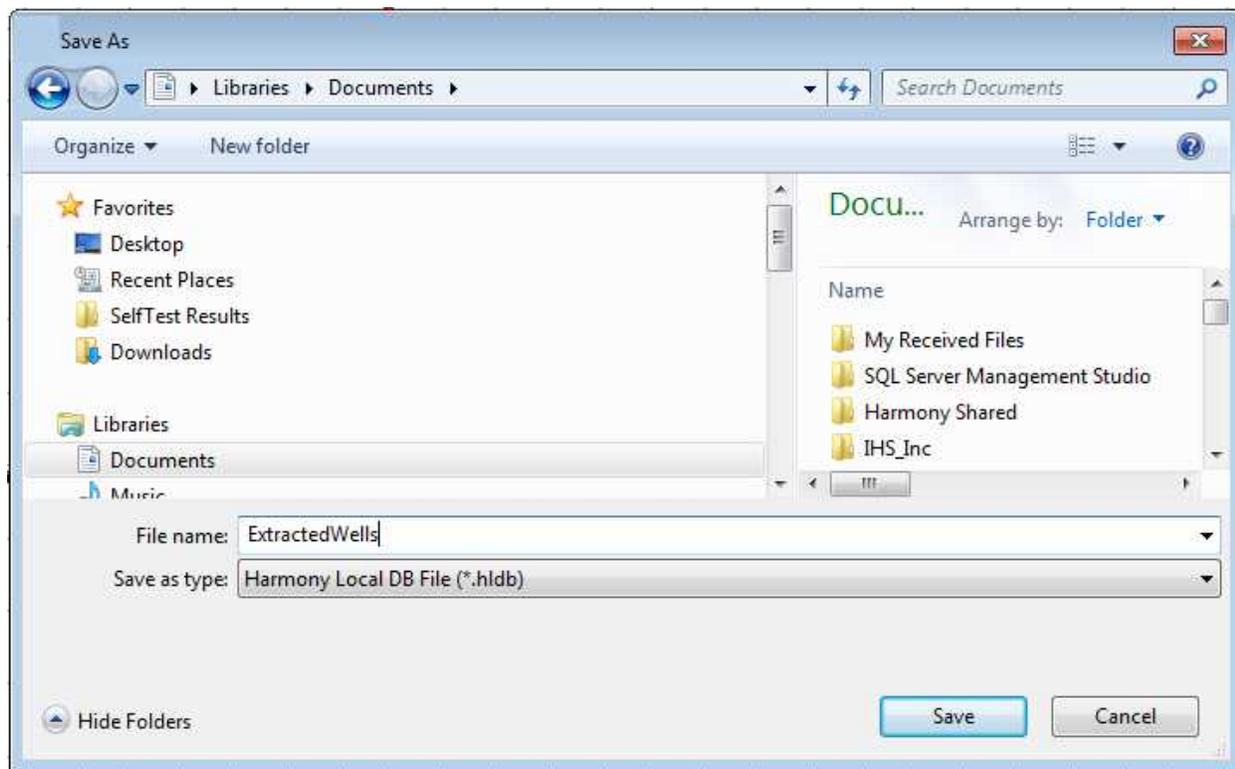
The following items are not exported:

- GIS layers (shapes, images, bubble maps, annotations, flags)
- Comparison plots
- Report sets
- Monitor results
- Economics cases
- Option settings, templates, and workflows (user-specific and saved to your workstation)
- Project filters and inactive hierarchy structures

Exporting entities

To export entities from a database:

1. Select the entities you want to export in the Entity Viewer (Hierarchy or Custom Groups pane). This can include wells or groups, but selections cannot be made in the Hierarchy and Custom Groups at the same time.
2. Click the **Export** icon () in the main toolbar and select **To .hldb file**.
3. Specify a location and filename, and save your .hldb file.



Connecting to an .hldb file

To connect to an .hldb file that was exported from Harmony Enterprise (by you or another user):

1. Click **Connect to, Existing .hldb file** in the Harmony Enterprise startup screen (opens when you launch Harmony Enterprise).



2. Browse to the location of the .hldb file and click **Open**.

Your exported wells are now treated as a new Harmony Enterprise database, and any changes you make in Harmony Enterprise are saved in the .hldb file.

Tip: When you connect to a local database, private groups (in the [Entity Viewer - Custom](#)) are converted to shared groups.

Export to Analytics Explorer

Analytics Explorer is an analytics-driven geological, geophysical, and engineering interpretation platform.

To export to Analytics Explorer:

Click the **Export** menu and select **To Analytics Explorer**, then:

- **New** — opens the Harmony Analytics dialog box. For more information, see the [Analytics Explorer help](#).
- **Existing** — browse to your Spotfire template file (.dxd extension).

Use workflows

A workflow is a collection of worksheets and analyses that can be applied to an [entity](#) as a set. Using a workflow eliminates the need to create the same worksheets and analyses for every entity with similar characteristics. Workflows also maintain worksheet and analysis customizations (for example, names, colors, axis ranges, etc.).

When an entity is selected for analysis, it is locked, so you are not able to apply a workflow to this entity while the lock is in place.

Tip: All workflows are user-specific. Therefore, any workflows you create are not seen by other users in a multi-user environment.

These items apply to workflows:

- [create a workflow](#)
- [modify a workflow](#)
- [apply a workflow](#)
- [Create Workflow dialog box](#)

You can *rename* or *remove* a workflow by clicking the **Launch Workflow** icon () and then right-clicking the workflow.

The following analyses cannot be included in workflows because they require user input in order to be created:

- ratio forecasts
- WOR / oil cut fluid forecasts
- consolidations
- custom forecasts
- [optimize](#) analyses

Create a workflow

To create a workflow:

1. Select an entity and click the **Analysis** tab. Create the worksheets and analyses to be included in the workflow, including any customizations for the plot.

Note: If a custom dataset does not exist when a template is applied, the dataset is not added to the plot.

2. Click the **Create Workflow** icon () on the main pane's toolbar.

The [Create Workflow dialog box](#) opens.

3. Click **New** and type a name for your workflow; click **OK**.
4. Click **Save**.

Your workflow is saved and can be viewed by clicking the **Launch Workflow** icon () on the main pane's toolbar.



Modify a workflow

To modify a workflow:

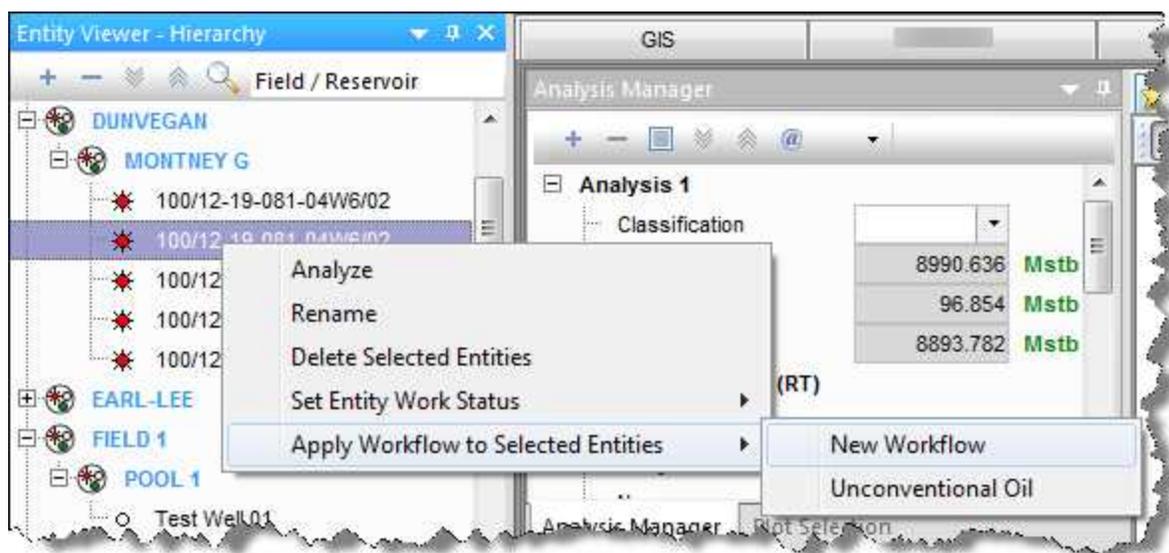
1. Select an entity for analysis (or group), and create or modify the worksheets and analyses you want to include in the new version of the workflow.
2. Click the **Create Workflow** icon () on the main pane's toolbar.
The Create Workflow dialog box opens.
3. Select the workflow name you want to replace in the **Workflow** drop-down list.
4. Click **Save**.

Apply a workflow

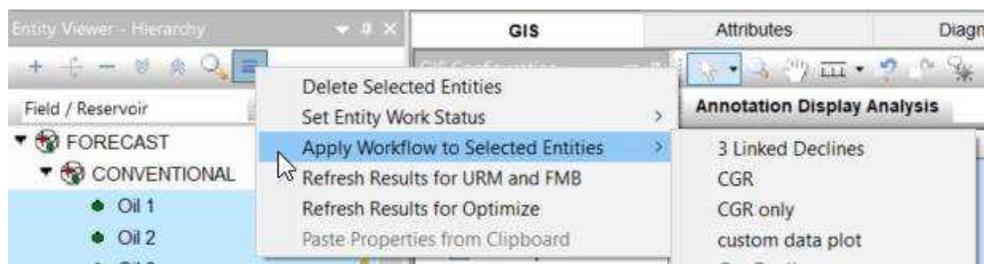
After you create a workflow, you can apply it to entities and groups.

To apply a workflow:

1. Select one or more entities in the Entity Viewer (Hierarchy or Custom).
2. Right-click and select **Apply Workflow to Selected Entities**; then select a workflow.



Or, you can click the **Contextual Commands** icon (☰) on the Entity Viewer's toolbar and select **Apply Workflow to Selected Entities**.



Note: If you right-click a selection when no workflows exist, (No Workflows Exist) is displayed in the context menu. Also, if you attempt to apply a workflow to an empty group, an error message opens stating that workflows cannot be applied to groups that do not contain any wells.

Alternatively, you can select an entity for analysis (or group), and then click the **Launch Workflow** icon (★) on the main pane's toolbar. Then either double-click the workflow, or click the blue arrow to the right of the workflow.



A dialog box opens where you can click a link to review settings in the [Options dialog box](#), and confirm your intention to apply the workflow.



The [Status Window](#) displays messages for the following:

- If your workflow is applied to the entities you selected.
- If your workflow could not be applied to all of the entities.
- If there are any analysis errors (for example, the data could not be "best fit").

Create Workflow dialog box

This dialog box is commonly used when you [create](#) or [modify a workflow](#).

- **Workflow** drop-down list — select your previously created workflow from the drop-down list. If you have not created a workflow, this list is blank.
- **New** button — opens the Workflow Name dialog box where you type a name for your workflow.
- **Worksheets** — click the checkboxes to select or deselect the worksheets for your workflow.

- **Lock Scaling** — keeps the x- and y-axis scale from the worksheet you are applying to your workflow.
- **Analyses** — click the checkboxes to select or deselect the analyses for your workflow.

Link / unlink analyses

By linking analyses you can combine multiple analyses in order to enforce consistency or generate calculated results. For example, you can link a Ratio Trend with a Decline analysis to calculate a rate forecast. Only Harmony Forecast analysis types can be linked, but the analyses must be of different types. When analyses are linked, they are displayed in the Analysis Manager under a single analysis name.

This is a list of analysis combination and generated results:

Analysis	Generated results
Decline + Decline	The ratio between the two rate forecasts are calculated. This is only done for the four default ratios in Harmony Forecast: GOR, WOR, WGR, and CGR.
Decline + Ratio Trend / Ratio Forecast	The rate forecast for the other fluid from the ratio is calculated. This requires a decline analysis on one of the fluids from the ratio, such as an oil decline and gas oil ratio.
Decline + Volumetrics	The recovery factor (RF) is calculated based on the combination of original fluid in-place from a volumetrics analysis and EUR from a decline analysis.
Decline + Material Balance	The RF is calculated based on the combination of original fluid in-place from a material balance analysis and EUR from a decline analysis.
Volumetrics + Material Balance	The drainage area for the volumetric analysis is calculated in order to match the original fluid in-place.
Decline + WOR Analysis	The final water cut is calculated based on the EUR from a decline analysis.

When analyses are linked, some analysis types permanently overwrite the results obtained by the other analysis. A summary of the order of precedence is listed below:

Parameter	Order of analysis type precedence
Original Oil in Place (OOIP) / Original Gas in Place (OGIP)	1. Material Balance 2. Volumetrics
Expected Ultimate Recovery (EUR)	1. Decline

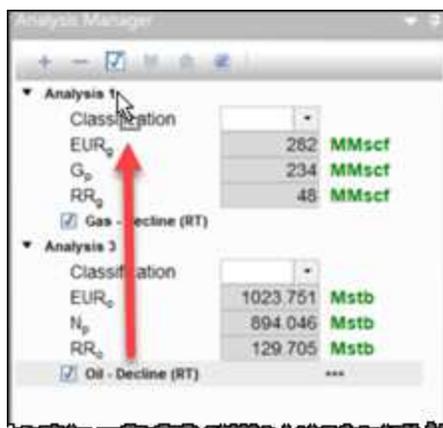
Parameter	Order of analysis type precedence
	2. Water-Oil Ratio
	3. Material Balance
	4. Volumetrics

Unlinking analyses does *not* restore the results of that analysis. For example, unlinking a Volumetrics analysis from a Material Balance analysis does *not* revert the OGIP of the Volumetrics analysis.

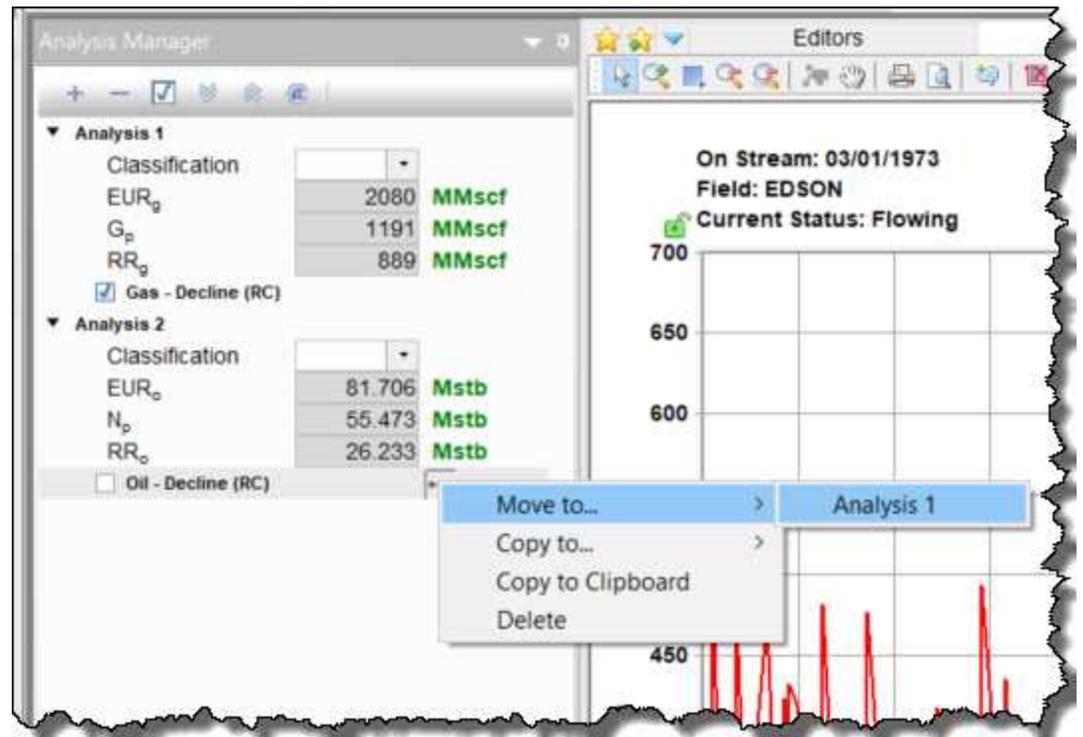
Linking analyses

To link analyses:

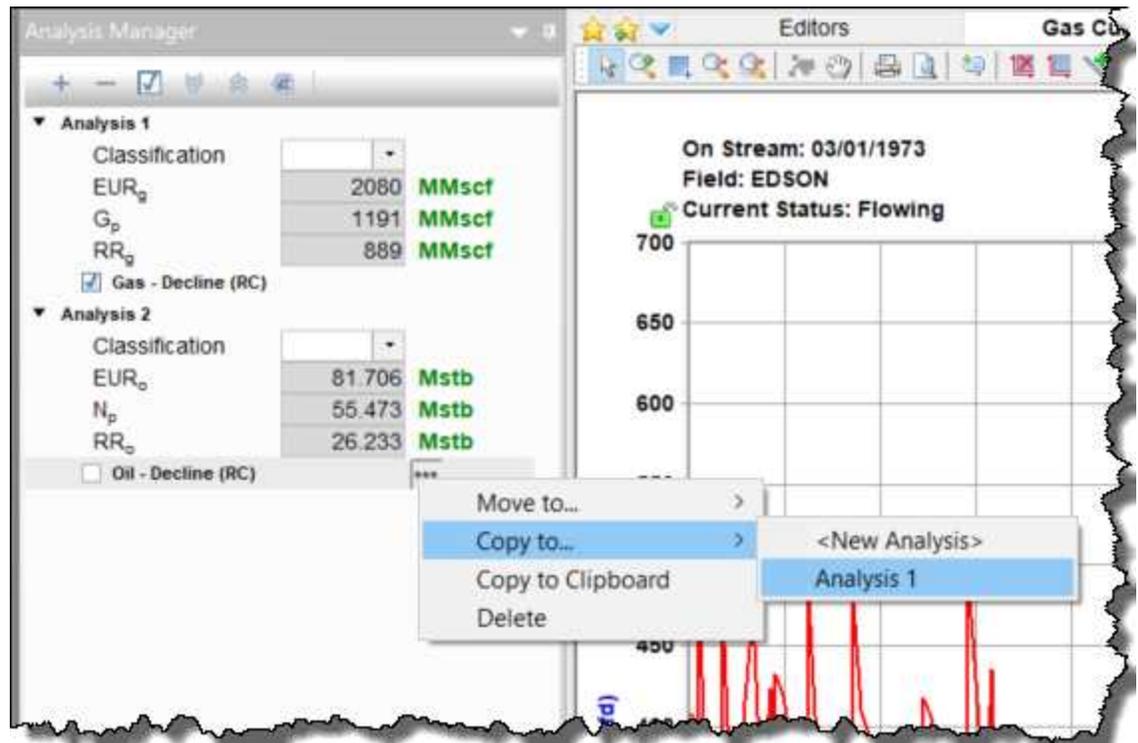
1. Create two analyses that can be linked.
2. Do one of the following:
 - Drag one analysis onto the name of the other analysis. (This option removes the selected analysis from the Analysis Manager.)



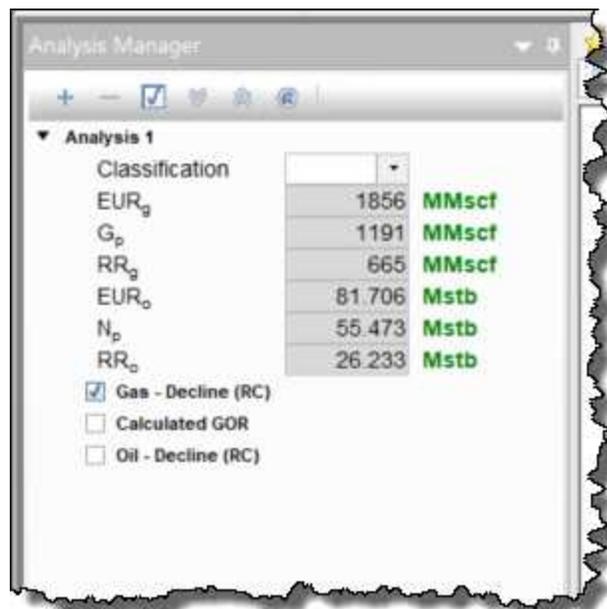
- Click the ... button for an analysis type, select **Move to**, and then select the name of the analysis to be linked. (This option removes the selected analysis name from the Analysis Manager.)



- Click the ... button of an analysis type, select **Copy to**, and then select the name of the analysis to be linked. (This option leaves the selected analysis in the Analysis Manager and merges a copy with the linked analysis.) If you duplicate an analysis, you can link it to multiple other analyses.



The two analyses are displayed in the Analysis Manager as a single combined analysis.

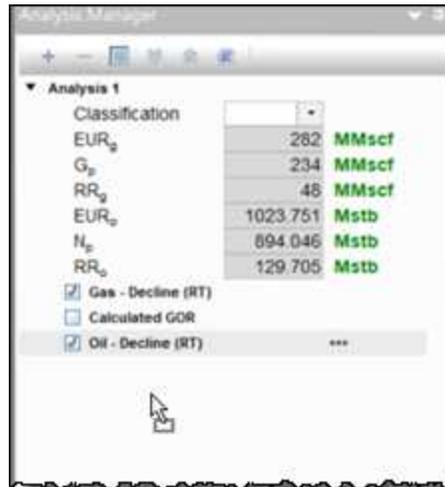


The new combined analysis can be compared to other analyses to strengthen confidence in their results, or as a diagnostics tool to discover where inaccuracies are.

Unlinking analyses

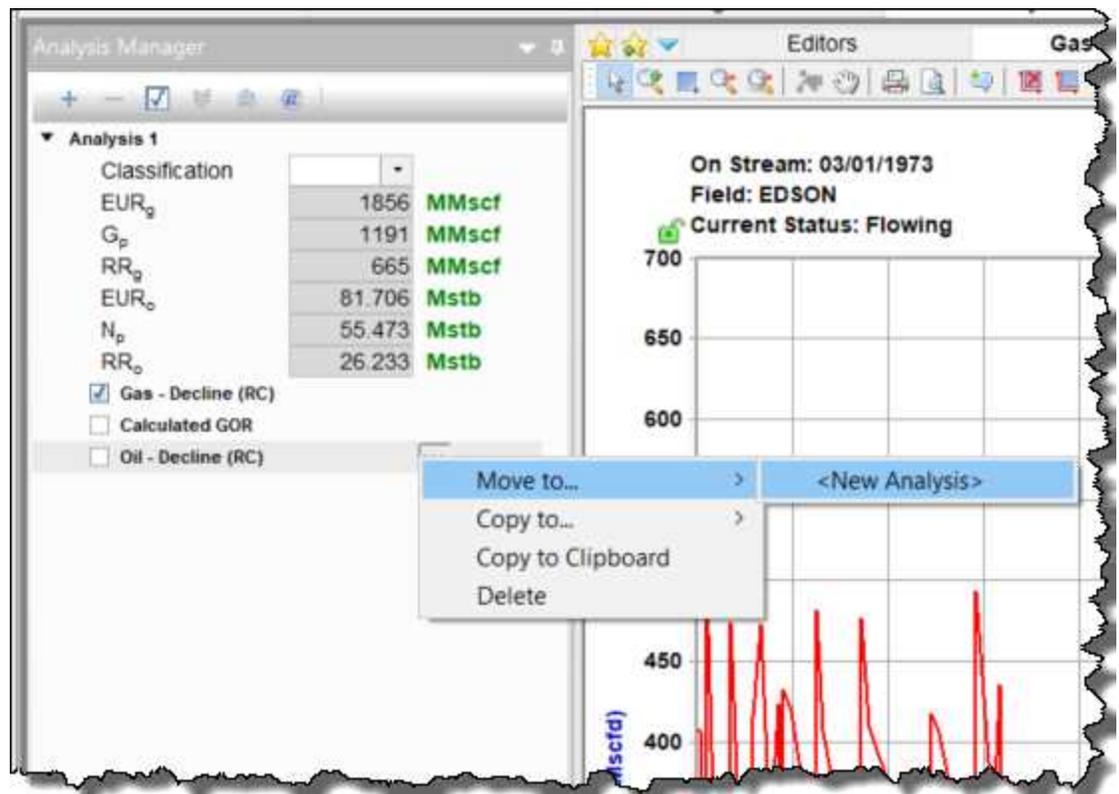
To unlink the analyses, do one of the following:

- Drag one of the analyses into an empty portion of the Analysis Manager.



- Click the ... button of an analysis type; select **Move to**, and then select **<New**

Analysis>



Analysis types

After you have added a worksheet, you can create an analysis. Harmony Enterprise supports the following analysis types:

With a Harmony Forecast license	With a Harmony Reservoir license	With a Harmony Optimize license
<p>Decline analyses:</p> <ul style="list-style-type: none"> <u>Decline</u> (Arps decline) <u>Multi-segment</u> <u>Stretched exponential</u> <u>Probabilistic</u> (beta) <u>Duong</u> <p>Typewell (the above decline analyses can be added to the <u>typewell worksheet</u>)</p> <p><u>Material Balance</u> analyses</p> <p><u>Volumetrics</u> analyses</p> <p>Ratio analyses:</p> <ul style="list-style-type: none"> <u>WOR</u> (water-oil ratio) <u>Oil cut</u> <u>Ratio trend</u> <p><u>Surveillance</u> analyses</p> <p>Production forecasts:</p> <ul style="list-style-type: none"> <u>WOR / oil cut forecast</u> <u>Ratio forecast</u> <u>Custom forecast</u> <p><u>Forecast consolidation</u></p>	<ul style="list-style-type: none"> <u>Typecurve</u> <u>FMB</u> <u>URM</u> <u>Analytical model</u> <u>Numerical model</u> <u>Numerical URM</u> <u>Probabilistic</u> <u>Multi-well model</u> 	<ul style="list-style-type: none"> <u>Gas IPR / TPC</u> (inflow / outflow) <u>Oil IPR / TPC</u> (inflow / outflow) <u>Flowing Gradient</u> <u>Advanced Forecast</u>

Advanced Forecast

Advanced Forecast is a production optimization tool for creating and evaluating different forecasts for a single well. This analysis must connect to an existing analytical or numerical model created with the Harmony Reservoir module.

After you pair a model, you can generate forecasts with varying constraints. Since this is a production optimization tool, the expected workflow is to start with an existing, history-matched model, and then create forecasts from it.

Multiple forecasts can be compared within the worksheet, either by qualitative analysis of the plotted forecasts through time, or by quantitative analysis of forecast results such as expected ultimate recovery (EUR) and recovery factor (RF).

Advanced Forecast provides additional benefits beyond the ability to show multiple concurrent forecasts. One benefit is the prediction of liquid loading in gas forecasts. Another benefit is the ability to display an inflow performance relationship (IPR) for the reservoir at any point in the forecast.

Furthermore, if you have a history-matched analytical or numerical model, then the expected workflow is to create one or more wellhead-pressure forecasts for which you can specify the wellbore configuration, and the date at which your wellbore configurations change. You can also customize your tubing configuration within the worksheet (instead of navigating back to the [Wellbore editor](#).)

Note: This analysis works with your Harmony Optimize™ license.

This analysis has the following icons:

-  **Delete** — removes the currently selected inflow, outflow, gradient, or forecast.
-  **Copy** — creates a duplicate of the currently selected inflow, outflow, gradient, or forecast. The name is appended with the word "Copy".
-  /  **Show / Hide** — toggle between showing or hiding the inflow, outflow, gradient, or forecast.

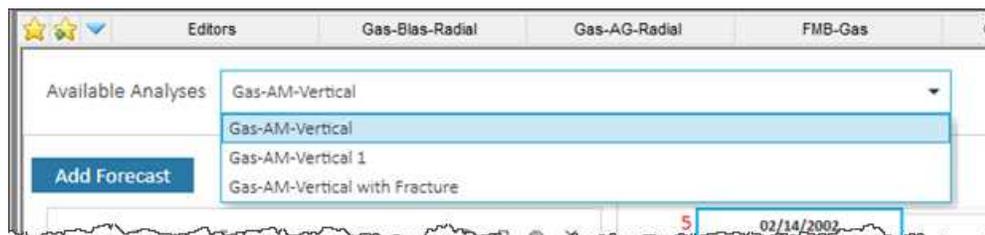
-  /  **Collapse / Expand** — closes / opens the details for the inflow, outflow, gradient, or forecast. If you see a red triangle () in the top left of a collapsed analysis, you need to investigate the required parameters.

Analysis selector

The **Available Analyses** drop-down list at the top of the window is used to pair the Advanced Forecast worksheet with a previously created analytical or numerical model. After you select a model, a Model Forecast box is displayed at the top of the Forecast pane on the left-side, and your model's original history match and forecast are displayed in a plot to the right.

Note: The Model Forecast box is read-only and replicates the forecast constraints used in the parent model's Forecast tab. This is an important distinction from forecasts created within the Advanced Forecast worksheet.

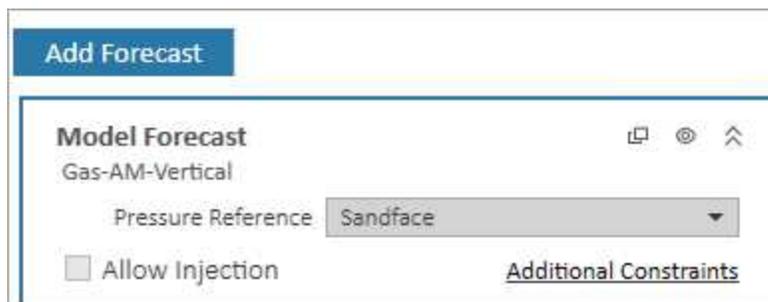
By selecting a different model, the worksheet changes to display advanced forecasts that are tied to the newly selected analytical or numerical model.



Note: Deleting the Advanced Forecast worksheet does not delete your forecasts; they can be viewed again by creating a new Advanced Forecast worksheet with the same model. Forecasts can be individually deleted either within the Advanced Forecast worksheet, or by deleting the source model itself.

Forecast pane

The Forecast pane on the left-side has the following items:



- **Add Forecast** button — click this button to create a forecast. Each time you click this button another Forecast box is created.
- **Pressure Reference** drop-down list — when controlling the pressure for forecasting an analytical model, select **Sandface** or **Wellhead**. For numerical models, only **Sandface** pressure can be used. For more information, see [forecasting using wellhead pressure](#).
- **Allow Injection** checkbox — a negative control rate (to forecast as injection) can be specified with analytical models. For more information, see the [analytical analysis](#).
- **Additional Constraints** link — opens a popup where additional constraints can be entered. For more information, see below.

Additional constraints

After you click this link, you can type your maximum rate and abandonment rate conditions. The available constraints depend on the fluid type, and can include the following:

- **Minimum Pressure** — (p_{min}) specifies the minimum sandface / wellhead pressure based on your Pressure Reference selection from the drop-down list.
- **Maximum Pressure** — $(q)_{max}$ sets a maximum rate to be applied during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted.
- **Abandonment Rate** — $(q)_{ab}$ sets the abandonment rate for the forecast. When the abandonment rate is reached, the forecast ends.

Forecast options

Each input is required to create a forecast segment. A forecast can consist of one segment – or many – depending on the number of operational changes specified in the forecast. Options include the following:

Segment 1

Start date: 2/14/2002

Duration: Required Months

End date: Select a date

Step count: Arithmetic

Control type: Pressure STEP | RAMP

Initial SF Pressure: Required psi(a)

Final SF Pressure: psi(a)

- **Time** — defines the length of each forecast segment and each timestep, and has the following inputs:
 - **Start Date** — determines the start of the forecast. This can be any time between the earliest and most-recent historical production date. If no historical production exists, this value defaults to today's date.
 - **Duration** — sets the length of the forecast segment. This can either be set to months or days.
 - **End Date** — sets the date at which the forecast segment terminates. If Start Date and Duration are populated, this input is calculated.
 - **Step Count** — sets the spacing of the timesteps, and can be set to either Arithmetic or Logarithmic. The "Arithmetic step" spaces the number of timesteps equally over the total duration of the period. The "Logarithmic step" spaces the number of timesteps logarithmically (that is, increased density near the beginning of the forecast).
- **Control** — defines how the operating conditions change over the forecast period, and has the following editable fields:
 - **Control Type** — sets what is used to calculate the forecast. For the analytical model, the forecast can be run using either flowing pressure, or the rate being analyzed.
 - **Interpolation** — can be set to either Step or Ramp. "Step" keeps the control type constant over the forecast period. "Ramp" varies the control type linearly from an initial value to a final value.
- **Sandface Pressure** — if the Control Type is set to Pressure, and the Pressure Reference drop-down list is set to Sandface, the sandface flowing pressure is used to set the flowing pressure for the forecast segment. If Interpolation is set to Step, only the initial pressure is specified. If Interpolation is set to Ramp, initial and final pressure are specified.

- **Wellhead Pressure** — if the Control Type is set to Pressure, and the Pressure Reference drop-down list is set to Wellhead, the wellhead flowing pressure is used to set the flowing pressure for the forecast segment. If Interpolation is set to Step, only the initial pressure needs to be entered. If Interpolation is set to Ramp, initial and final pressure need to be entered.
- **Rate** — if the Control Type in a period is set to Rate, an editable field is displayed, and it is used to set the rate for the forecast period. If Interpolation is set to Step, only the initial rate's field is editable. If Interpolation is set to Ramp, initial rate and final rate are editable.
- **Ratios** — these additional forecast constraints are only available under certain conditions.
 - **WGR** — available when using a gas analytical model, and the Pressure Reference is set to **Wellhead**. By selecting the WGR checkbox at the top of the Forecast pane, additional input fields are displayed below the Control Type section. The WGR in the forecast segment can be set to either Step or Ramp.
 - **CGR** — available when using a gas analytical model, and the gas type is set to **Liquid-Rich Gas** in the [Properties editor](#), and the vaporized oil ratio correlation is set to **Constant Rv** also in the Properties editor, and the Pressure Reference is set to **Wellhead**. If these conditions are met, then selecting the **Separate Recombined Gas** checkbox at the top of the Forecast pane displays additional fields below the Control Type section. The CGR can be set to either Step or Ramp.
 - **GOR** — available when using an oil analytical model, and the Pressure Reference is set to **Wellhead**. By selecting the GOR checkbox at the top of the Forecast pane, additional input fields are displayed below the Control Type section. The GOR in the forecast segment can be set to either Step or Ramp.
 - **WOR** — available when using an oil analytical model, and the Pressure Reference is set to **Wellhead**. By selecting the WOR checkbox at the top of the Forecast pane, additional input fields are displayed below the Control Type section. The WOR in the forecast segment can be set to either Step or Ramp.

Customize Wellbore

This option is available when the Pressure Reference is set to **Wellhead**.

By clicking the **Customize** button, you can create and edit customized wellbore configurations. Options include: flow path, bottom depth of tubing, tubing, inner diameter, and tubing outer diameter.

Add Segment

You can add additional segments to the forecast. This can be used to schedule a change in a well-bore configuration, operating condition (for example, rate control vs. flowing pressure control), or additional fluid production (for example, WOR increase).

Subsequent forecasts must start at the date the preceding forecast ends. Segments can also be copied, deleted, expanded, and collapsed.

Forecast summary

When you click the **Collapse** icon (), a summary of the forecast is displayed. Results depend on the fluid type, but items could include the following:

- **EUR** — expected ultimate recovery
Note: For wells with historical data, EUR is defined as the cumulative of the historical data up to the beginning of the forecast, after which time, the synthetic cumulative is calculated from the model until the end of the forecast.
- **RR** — remaining recoverable
- **RF** — recovery factor (as a percentage)
- **Duration** — total duration of all forecast segments



Model Forecast			
Gas			
EUR _g	1,918.41 MMscf	RF _g	76.9 %
RR _g	765.70 MMscf	Duration	1,000 month

Plots

There are two plots in the center of the window: a Forecast plot and an IPR / TPC plot. The **Auto-scale** checkbox fits the plot to the maximum viewable area of the screen.

Forecast plot

This plot is used to display various production forecasts for comparison. Color-coding matches the fluid types; red for gas, blue for water, green for oil / condensate, and purple for recombined gas. Brown denotes flowing sandface pressure.

Historical data points are displayed using dots, whereas forecast-series data is displayed using lines. For gas wellhead forecasts, the transition from a solid to a dashed line denotes the transition between operating above and below the critical liquid loading rate, respectively.

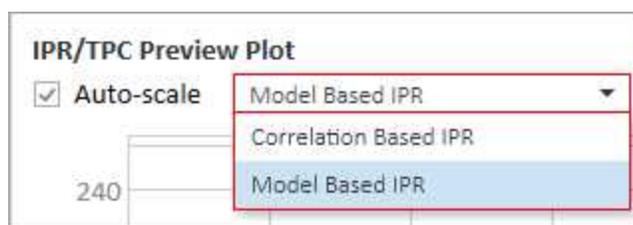
Multiple forecasts can be displayed at the same time, but only one forecast can be selected. The forecast is denoted by a dark blue border around its forecast box in the Forecast pane. Thicker lines are displayed for the fluid rates and the flowing-pressure series. Active, but deselected forecasts, are displayed with thinner lines on the plot. By right-clicking the plot, you can copy the selected forecast's tabular values for pasting to another application (for example, Excel).

The vertical blue "Time / Date selector" is used to specify a forecast step at which to calculate the IPR curve (and outflow for wellhead forecasts) in the IPR / TPC plot at the bottom of the window. This Time / Date selector can be moved by clicking-and-dragging either the line, or the annotation at the top of the line, or by interacting with the annotation itself. The annotation has two states: a minimal display when the mouse is not hovering over the Forecast plot, and a full display when the mouse is hovering over the Forecast plot.



IPR / TPC Preview Plot

This plot is used to display the IPR curve for the selected forecast at the time specified by the Time / Date selector. You can select either a correlation-based or model-based IPR from the drop-down list.



Correlation-based IPR

After you select **Correlation-based IPR**, the IPR is created using a Simplified C,n correlation (assuming an 'n' value of 1) for gas wells, and a Vogel IPR correlation for oil wells.

If the Pressure Reference is set to **Wellhead**, a TPC is displayed using the wellbore configuration used at the time specified by the Time / Date selector. The intersection of the IPR and TPC correspond to the operating point and the resultant rate and flowing sandface pressure at the Time / Date selector-specified time. If the operating point is below the critical liquid loading rate, the operating point is red.

By right-clicking the plot, you can copy the inflow and outflow curves in tabular format, to be pasted to another application (for example, Excel).

Model-based IPR (not applicable to numerical models)

After you select **Model-based IPR**, the IPR is calculated directly from the analytical model you created.

- The IPR is calculated using 32 individual forecasts that are performed on the analytical model.
- Each of the 32 forecasts is performed at constant pressure, with the pressures being equally spaced from reservoir pressure to minimum pressure.
- Each forecast is performed for one month (31 days, with 31 steps).
- The final rate and flowing sandface pressure from each forecast are used to build the IPR.

By right-clicking the plot, you can copy the inflow and outflow curves in tabular format, to be pasted to another application (for example, Excel).

Send To button

After clicking this button, you can send / push IPRs and TPCs from the Advanced Forecast worksheet to an IPR / TPC worksheet (that is, Gas IPR / TPC, Oil IPR / TPC). This exports the IPR (and TPC) displayed on the IPR / TPC Preview plot. The pushed curves are displayed on the destination worksheet as read-only Custom Table Inflow and Outflow analysis panes.

You can select an existing IPR / TPC worksheet (which matches the primary fluid of the Analytical model), or create and type a name for a new worksheet in the Send To dialog box.

You can send either one IPR, or up to 10 IPRs at one time with a manually specified number of forecast steps between subsequent IPRs. If the selected Forecast is set to Wellhead, then you

can send a TPC corresponding to the wellbore configuration and wellhead flowing pressure observed at the specified forecast step.

After an IPR is sent to an IPR / TPC worksheet, a confirmation dialog box opens. Navigate to the destination worksheet to view your pushed Inflow analysis pane.

After a curve is pushed from the Advanced Forecast worksheet, this curve is a standalone analysis. There is no synchronization between the Advanced Forecast or the Analytical model, and the resultant Inflow and/or Outflow analysis panes. For this reason, additional information is displayed on a pushed curve.

Analytical model

Analytical models are used to validate interpretations and provide production forecasting. For more information, see [analytical models theory](#). Analytical models assume single-phase flow in the reservoir and are available for gas, oil, and water production with the following options:

- Vertical
- Vertical with Fracture
- Horizontal
- Hz Multifrac: Enhanced Frac Region
- Hz Multifrac: General Multifrac

Note: This analysis works with your Harmony Reservoir™ license.

Before you start, make sure that all required information is added to the Harmony Enterprise project. Well production data (rates and sandface pressures) should be populated in the [Production editor](#), and reservoir and fluid properties should be specified in the [Properties editor](#).

We recommend that you perform an analysis prior to using the analytical model because this gives you an idea about which values to use. For example, for conventional wells, a flowing material balance (FMB) gives an estimate for original fluid in-place, and the use of a [typecurve](#) analysis provides insight about permeability, skin, reservoir shape / size, and fracture properties. For unconventional wells, an [unconventional reservoir analysis](#) can be used to estimate permeability, fracture length, apparent conductivity, and the size of the stimulated reservoir volume.

Analytical Model pane

In the Analytical Model pane, enter the required parameters, and select your calculation method from the primary toolbar (CalcP, CalcR, or CalcBoth).

Primary toolbar

There are four toolbars: primary, secondary, Plots sub-tab, and Forecast sub-tab.

The primary toolbar has the following important icons:

-  **Defaults** — copies parameters from the Properties editor or other IHS Reservoir worksheets.

Or, if you want to copy only one parameter from the analysis, click the **View Defaults and Limits** button to the right of the field in the Analytical Model pane.

Note: Parameters copied from the reservoir or another analysis are displayed in a gray font. This indicates that they match the default. You can type new values for any parameter, or change values for some parameters by moving elements of the schematic. Parameters, which do not match the default, are shown in a black font.
-  **Automatic Parameter Estimation (APE)** — while APE is running, selected parameters are automatically varied to minimize the error between the simulated pressure / rate and the actual pressure / rate depending on the calculation method (see CalcP, CalcR, and CalcBoth below). The updated simulated pressure / rate is shown on the plots while the calculation is running. For more information, see using APE.

Important: The purpose of history matching is to get the calculated pressures / rates to reproduce actual pressures / rates as closely as possible by changing the model's parameters. You can vary model parameters manually, or use APE.
-  **AutoCalc** — recalculates automatically each time you change model parameters.
-  **Synthesize** — if you do not click the AutoCalc icon, you must click this icon every time you want to recalculate the model.
-  **CalcP** — calculates the sandface flowing pressure based on measured rate. The pressure is calculated and minimized.

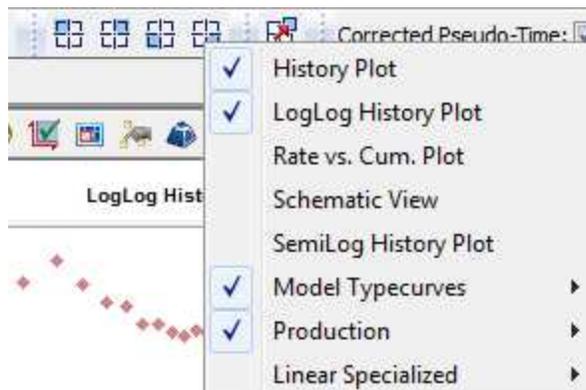
-  **CalcR** — calculates the rate based on given sandface flowing pressures. The rate is calculated and minimized.
-  **CalcBoth** — calculates CalcP and CalcR. Both pressure and rate are calculated and minimized.
-  **Derivative Options** — opens the Options dialog box where you can select Standard (points), Bourdet (cycles), or Difference.
-  **Copy to / Paste from the Clipboard** — copies and pastes data from the clipboard.

For a description of common icons, see [toolbars](#).

Secondary toolbar

By default, the secondary toolbar is located to the far right of the primary toolbar. (You can move the icons in the secondary toolbar by clicking the dotted line to the left of the icons.)

By default, the Analytical Model Dashboard displays model schematics and three plots with measured and calculated data. You can change this display (that is, switch plots and their positioning) by clicking one of the **Add an Available View** icons (upper left, upper right, lower left, lower right) and selecting the plot you want.



-  **Add Floating View** — opens the plot you select from the drop-down list in its own window.
- **Corrected Pseudo-Time** — toggles corrected pseudo-time on or off.

Sub-tabs

There are three sub-tabs: Plots, Forecast, and Tables.

Plots

This sub-tab displays your analytical model dashboard, which you can customize using the [secondary toolbar](#). For information on a plot's context menu, see [plot options](#).

Toolbar

This toolbar is located on the Plots sub-tab and has the following important icons:

-  **Reset Plot Attributes** — resets your plot attributes to default settings.
-  **Enable / Disable Square LogLog Plot** — changes the range of the x- and y-axes, so that the resolution of a log cycle is consistent between the axes (for example, a log cycle equals 200 pixels on both axes).
-  **Weigh Data Points** — used to emphasize matching to specific data points when using APE (for example, the last part of the production). The cursor changes to a [spray gun](#) when clicked. Weighted data points are displayed in a brighter color and are given a 100% weighting; unweighted points are given a 10% weighting. (The weighting is displayed when you hover over the data point.)
-  **Copy** — copies plot data.
-  **Select Anchor Point** — attempts to initialize the anchor to the first measured pressure. If this fails, click the location you want within the plot to set the anchor location. An annotation is shown at the anchor location while this functionality is enabled. Dragging the annotation arrow to a different point updates the calculations. For more information, see [anchoring](#).
Tip: The Anchor option is currently only available for analytical models in Calculate Pressure ([CalcP](#)) mode.
-  **Hide the Toolbar** — hides the toolbar. If you want the toolbar displayed, right-click the plot and select **Show Toolbar**.

For information on common plot icons, see [plot toolbars](#).

Forecast

This sub-tab has a toolbar, and displays your forecast: options, constraints, and results.

After the model has been populated (either by entering values, or by clicking the [Defaults icon](#)) and calibrated to the production and pressure data through history matching (click the [Automatic Parameter Estimation icon](#)), production forecasts can be created and compared under a variety of different constraints.

Toolbar

This toolbar is located on the Forecast sub-tab and has the same common icons described in [plot toolbars](#).

Forecast options

The Forecast Options section is where forecast periods are defined according to either durations (for example, months), or dates.

- Setting the forecast time method to **Duration** begins a forecast at a specified start date. Forecast periods are then defined in the forecast table according to a length of time (the default is months). For each forecast period, different operating conditions can be specified.
- Setting the forecast time method to **Start Date** creates a forecast of a specified length of time (the default is months). Forecast periods are then defined in the forecast table according to calendar dates.



If you select **Duration** from the Forecast Time Method drop-down menu, the Start Date is automatically populated. (You can change this date later, if needed.)

If you select **Start Date** from the Forecast Time Method drop-down menu, enter a value for Duration (that is, the total length of the forecast).

Forecast Flowing Pressure — when controlling the pressure for forecasting, select whether sandface or wellhead pressure is specified. For more information, see [forecasting using wellhead pressure](#).

Allow Injection — a negative control rate (to forecast as injection) can only be specified when this checkbox is selected. If this option is deselected, the forecast stops if the average pressure intersects flowing pressure.

Further details about each forecast period are entered in the forecast options table.

	Time			Control		Sandface Pressure	
	Step Type	Duration	# of Steps	Interpolation Method	Control Type	Initial	Final
		month				psi(a)	psi(a)
1	Arithmetic	Required	Required	Step	Pressure	1626.85	

Each row of the table above represents a forecast period. An additional forecast period can be added each time an operational change is encountered (for example, the flowing pressure decreases when a compressor is added). The forecast options table has the following sections:

- **Time** — defines the length of each forecast period and each timestep, and has the following columns:
 - **Step Type** — sets the spacing of the timesteps, and can be set to either Arithmetic or Logarithmic. The Arithmetic step type spaces the number of timesteps equally over the total duration of the period, whereas the Logarithmic step type spaces the number of timesteps logarithmically (that is, increased density near the beginning of the forecast).
 - **Forecast Time Method (Duration / Start Date)** — sets the length of the forecast period. If the Forecast Time Method is set to Duration, this column shows Duration. If the Forecast Time Method is set to Start Date, this column show Start Date.
 - **# of Steps** — sets the number of timesteps in the forecast period.
- **Control** — defines how the operating conditions change over the forecast period, and has the following columns:
 - **Interpolation** — can be set to either Step or Ramp. "Step" keeps the control type constant over the forecast period. "Ramp" varies the control type linearly from an initial value to a final value.
 - **Control Type** — sets what is used to calculate the forecast. For the analytical model, the forecast can be run using either flowing pressure, or the rate being analyzed.
- **Sandface Pressure** — if the Control Type is set to Pressure, the Sandface / Wellhead Pressure column is displayed (depending on the Forecast Flowing Pressure option), and it is used to set the flowing pressure for the forecast period. If Interpolation is set to Step, only the initial pressure is specified. If Interpolation is set to Ramp, initial and final pressure are specified.
- **Gas Rate** — if the Control Type in a period is set to Gas Rate, this column is displayed, and it is used to set the rate for the forecast period. If Interpolation is set to Step, only the initial rate cell is editable. If Interpolation is set to Ramp, initial rate and final rate are editable.

Forecast constraints

The Forecast Constraints section is where maximum rate and abandonment rate conditions for the forecast can be entered. The available constraints depend on the fluid type, and can include the following:

- p_{\min} — specifies the minimum sandface / wellhead pressure based on the Forecast Flowing Pressure option.
- $(q)_{\max}$ — sets a maximum rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted.
- $(q)_{\text{ab}}$ — sets the abandonment rate for the forecast. When the abandonment rate is reached, the forecast ends.

Forecast results

The Forecast Results section is where the results of the forecast are summarized. Available results depend on the fluid type, and can include the following:

- EUR — expected ultimate recovery.
Note: For wells with historical data, EUR is defined as the cumulative of the historical data up to the beginning of the forecast, after which time, the synthetic cumulative calculated from the model is used until the end of the forecast.
- RR — remaining recoverable.

Tables

The sub-tab displays your history match (after you use the [synthesize](#) or [APE](#) functionality) and forecast data (after you populate all the required values on the Forecast tab) in a tabular format. For more information, see [tables](#).

Forecasting gas condensate systems

Analytical models in Harmony Enterprise can only analyze single-phase systems. For condensate systems, gas and condensate rates measured at the surface are recombined into a single-phase rich gas for analytical modeling. When forecasting, however, the recombined gas rate must be split back out into gas and condensate rates for estimating production measured at the surface. The main procedure to split the recombined condensate-rich gas into separator gas and condensate is as follows:

- Calculate the recombined gas rate factor (RGRF), which is dependent on the instantaneous value of the condensate gas ratio (CGR).
- $q_{\text{sep gas}} = q_{\text{rec}} / \text{RGRF}$
- $q_{\text{cond}} = q_{\text{sep gas}} \times \text{instantaneous CGR}$

Note: RGRF is calculated from separator conditions, condensate gravity, gas gravity, and CGR.

- q_{rec} = recombined gas rate (rich gas rate); $q_{sep, gas}$ = separator gas rate (dry gas rate); q_{cond} = condensate rate

There are two options that control how CGR is calculated over the forecast period:

1. CGR changes with time:

- In the Properties editor, select **Gas Condensate / Recomb** from the Gas Type drop-down menu.
- In the Forecast tab, under Forecast Options, select the **Separate Recombined Gas** checkbox.



This results in additional columns (that is, Initial CGR and Final CGR) being added to the Ratios section of the forecast table.

	Time			Control		Sandface Pressure		Ratios		
	Step Type	Duration	# of Steps	Interpolation	Control Type	Initial	Final	Ratio Interpolation	Initial CGR	Final CGR
		month				psi(a)	psi(a)		bbiMMscf	bbiMMscf
1	Arithmetic			Step	Pressure			Step		

- Fill in the required inputs in the forecast table. The CGR automatically defaults to the value that was entered in the Properties Editor. However, this value can be edited.
- To enter a CGR that varies linearly over the forecasted period, select **Ramp** for the Ratio Interpolation method, then enter a Final CGR value.

	Time			Control		Wellhead Pressure		Ratios		
	Step Type	Duration	# of Steps	Interpolation	Control Type	Initial	Final	Ratio Interpolation	Initial CGR	Final CGR
		month				psi(a)	psi(a)		bbiMMscf	bbiMMscf
1	Arithmetic	Required	Required	Step	Pressure	Required		Ramp	Required	Required
2	Arithmetic			Step	Pressure			Ramp		

2. CGR changes with flowing pressure according to the Rv correlation:

- In the Properties Editor, select **Gas Liquid Content / Rv** from the **Gas Type** drop-down menu.
- In the Forecast tab, select the **Separate Recombined Gas** checkbox to split the calculated rich-gas rate into separator gas and condensate using the Rv functionality that controls the rate by sandface flowing pressure.

The resulting forecast graph and table show recombined gas, gas (dry), and condensate rates.

In splitting the forecast of analytical models, the assumption is that these effects / properties in the reservoir can be ignored:

- liquid drop-out on material balance
- liquid drop-out on skin
- liquid drop-out on gas composition (that is, recombined gas-specific gravity)
- liquid drop-out on fluid properties that change (that is, viscosity, compressibility, and the compressibility factor)

Note: The effect of liquid blockage on well productivity can be modeled by increasing skin with time.

Forecasting using wellhead pressure

Disclaimer: Wellhead forecasting has not been implemented for multilayer wells, nor for single-layer wells with wellbore configurations with their Flow Path set to Gas Lift.

By default, analytical models use sandface pressures for forecasting. When the Control Type is set to Pressure, analytical models calculate production rates based on sandface flowing pressure. When the Control Type is set to Rates, models calculate sandface flowing pressure based on rates.

With analytical models, you can forecast production rates from wellhead flowing pressure. When the Wellhead Flowing Pressure option is selected, and the Control Type is set to Pressure, analytical models calculate production rates based on wellhead flowing pressure.

After you have defined your wellbore in the [Wellbore editor](#), and created an analytical model, click the **Forecast** tab and make sure that **Wellhead** is selected from the Forecast Flowing Pressure drop-down menu.

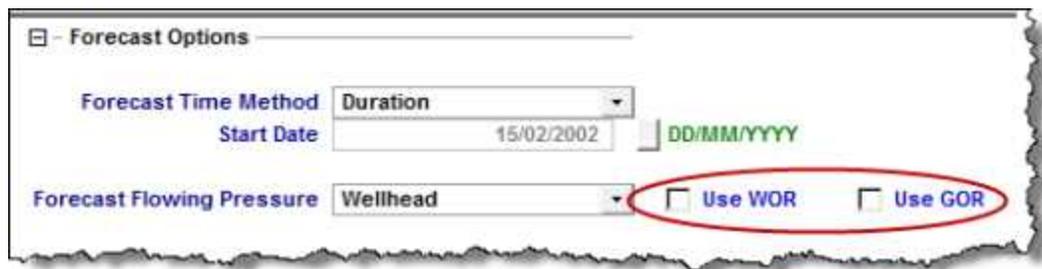


For the Control Type:

- If Pressure is selected, enter the wellhead flowing pressure.
- If Rate is selected, both sandface and wellhead flowing pressures are calculated during the forecast; however, only sandface flowing pressures are displayed on the Results plot. Both the sandface $(p_{wf})_{calc}$ and wellhead flowing pressures $(p_{tf})_{calc}$ are displayed in the Tables tab.

When multiple phases are present in the wellbore, pressures should be calculated based on the multiphase flow rates. To enable multiphase wellbore calculations, the fluid ratio must be defined over the forecast period. Fluid ratios are defined as follows:

- Under Forecast Options, select the appropriate fluid ratio. This results in additional columns being added to the forecast table under the Ratios section.



Note: Available fluid ratios depend on the analysis type. Gas wells show WGR, while oil wells show WOR and GOR.

- Set the ratio interpolation method as either Step (default setting) or Ramp. "Step" defines a constant ratio value over the forecast period, while Ramp allows the ratio value to vary linearly over the forecast period.

Forecast Options

Forecast Time Method: Duration
Start Date: 24/10/2012 DD/MM/YYYY

Forecast Flowing Pressure: Wellhead Use WOR Use GOR

	Time			Control		Wellhead Pressure		Ratios		
	Step Type	Duration	# of Steps	Interpolation	Control Type	Initial	Final	Ratio Interpolation	Initial WOR	Final WOR
1	Arithmetic	month		Step	Pressure	psia	psia		bb/stb	bb/atb

Forecast Constraints

p_{min} psia $(Q_o)_{max}$ stb/d $(Q_o)_{min}$ stb/d

- Specify values for the ratio over the forecast period. If Step was selected as the interpolation method, enter an Initial value. If Ramp was selected, enter Initial and Final values.

Note: When the Wellhead Flowing Pressure option is selected, the p_{min} forecast constraint is the minimum wellhead pressure (as opposed to minimum sandface pressure when the Sandface Pressure option is selected).

Default values for fluid ratios (for example, WGR, WOR, and GOR) are calculated based on the reported production rates at the last historical date.

Note that multiphase flow rates are only used in the wellbore calculation, which does the conversion between sandface and wellhead pressures. Multiphase flow rates are not used for any reservoir calculation.

Test design

Test design also uses the same Forecast tab, but its purpose is different. Test design is usually performed for green fields without any production data, and is used to:

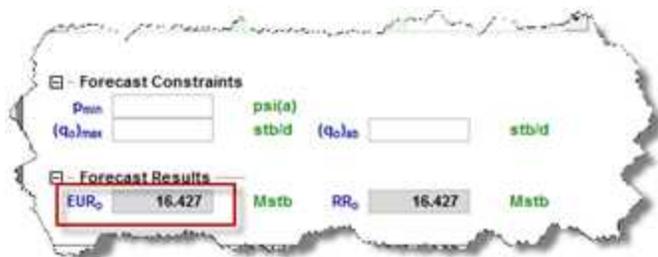
- get an estimate of expected production volumes
- see the effect of various reservoir and completion parameters

To start a test design, you need to create a new well (in the Entity Viewer) and fill in the required properties in the Properties editor.

Estimating expected production volumes

In the Forecast tab, set the forecast duration, # of steps, and forecast control.

Your forecast is calculated and displayed on the Results plot. Expected ultimate recovery (EUR) is displayed in the Forecast Results section.



Evaluating the effect of various parameters

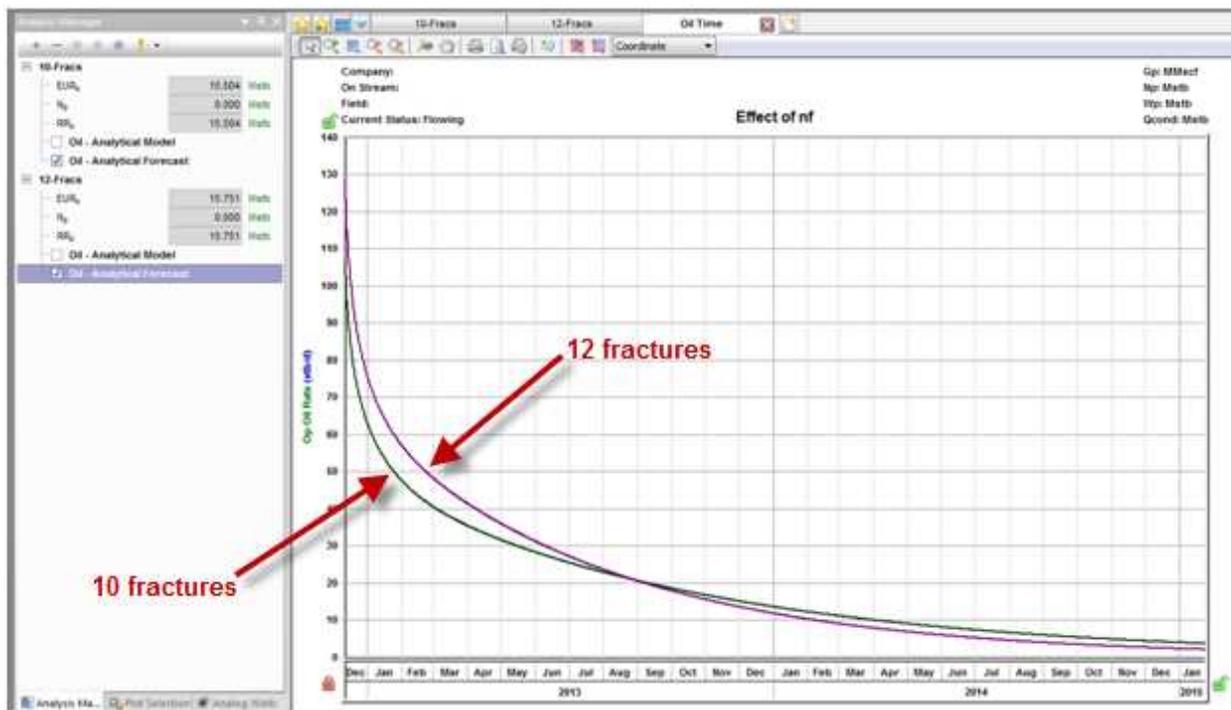
To have a better idea of possible outputs (for example, expected production volume estimates), you may want to see how results differ when you change some of the model parameters. This can be best illustrated with an example.

Test design example

Assume you have one model with a horizontal multifrac completion with a test design, and you want to see the effect of changing the number of fractures (n_f).

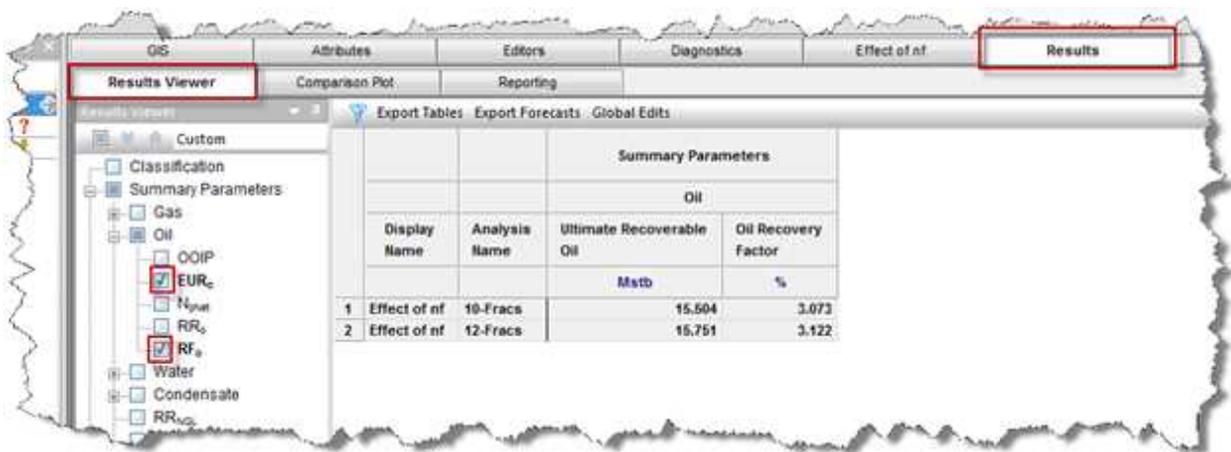
1. Create an analytical model of the same type.
2. Copy all the parameters from the existing model to the new one by clicking the **Defaults** icon (), and then change the number of fractures (n_f) for the new model.
3. Fill in all the Test Design parameters in the same way as the original model.
4. Right-click the analysis tab for both analyses to rename them, so they are easily identified.
5. Compare forecasts for both models using the [comparison plot](#).
Or, create a Rate Vs. Time analysis, and select the checkboxes to compare both models on a plot.

The plot below compares forecasts for models with 10 and 12 fractures. This plot illustrates that the model with 12 fractures has higher initial production, but later the rate for the model with 10 fractures becomes higher. Expected ultimate recoveries (EURs) are shown as well.



Following the same steps, you can add more models to compare the effect of various parameters.

If you have many models, and want to compare the summary parameters (that is, EUR, or recovery factors), use the [Results Viewer](#).



Advanced analytical model options

Advanced analytical model options include:

- [Adsorption](#)
- [Changing skin](#)
- [Changing storage](#)
- [Dual porosity](#)
- [Geomechanical](#)
- [Constant-pressure boundaries](#)
- [PVT pressure](#)

Other advanced options include:

- [Anchoring](#)
- [Injection](#)
- [Using automatic parameter estimation](#)

Adsorption option

To include the effect of adsorbed gas, click the **Adsorption** checkbox in the Analytical Model or Numerical Model pane. Note that this option cannot be used for models that include oil or condensate.

For more information, see [Langmuir isotherm](#).

After you select **Adsorption** in the selection tree, these properties are displayed:

- **V_{LS}, P_{LS}** — Langmuir volume and Langmuir pressure (for shale).
- **ρ_b** — bulk density (for shale).

You can also select **Ads. Sat.** (adsorption saturation correction) in the selection tree, with the following properties:

- **ρ_{ads}, S_{ads}** — density of the adsorbed gas phase, and adsorbed gas saturation. For more information, see the [shale adsorption correction](#).

Changing skin option

To include changing wellbore skin at specific points in time, click the **Chg. Skin** checkbox in the Analytical Model or Numerical Model pane.

For more information, see [time-dependent skin](#).

Changing storage option

To include changing wellbore storage, click the **Chg. Storage** checkbox in the Analytical Model pane.

For more information, see [wellbore storage](#).

Geomechanical option

To include the effects of changing formation compressibility and permeability related to reservoir pressure, click the **Geomechanical** checkbox in the Analytical Model or Numerical Model pane.

For more information, see [geomechanical reservoir models](#).

Constant-pressure boundaries

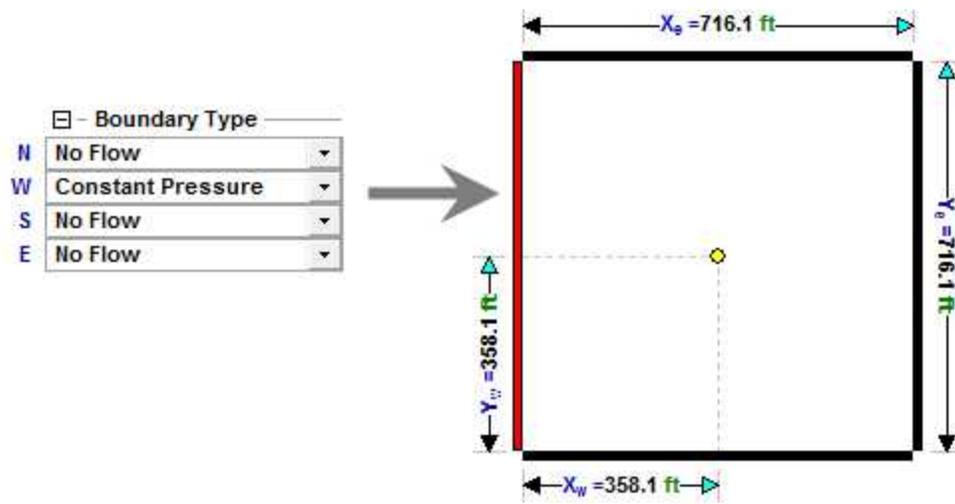
A constant-pressure boundary is a boundary that provides pressure support, and this kind of boundary can be used to model reservoirs with aquifer support or waterflooding.

You can introduce constant-pressure boundaries for the following analytical models:

- [Vertical](#)
- [Vertical with fracture](#)
- [Horizontal](#)
- [Asymmetrical horizontal multfrac](#)

To model constant-pressure boundaries:

1. Expand the **Boundary Type** section in the Analytical Model pane.
The boundary types for North, West, South, and East boundaries are listed.
2. Click the drop-down lists to change the boundary type to **Constant Pressure** for any of the boundaries.
3. If you set any of the boundaries to be a constant-pressure boundary, the model schematics and calculations change accordingly. No-flow boundaries are displayed in black, and constant-pressure boundaries are displayed in red.



You can switch between boundary types by changing values in the drop-down lists, or by clicking boundaries in the schematics.

PVT pressure option

To include the effect of oil PVT changes, click the **PVT Pressure** checkbox in the Analytical Model pane. Note that this option does not apply to gas or water models.

For more information, see [oil PVT change during reservoir depletion](#).

Dual porosity option

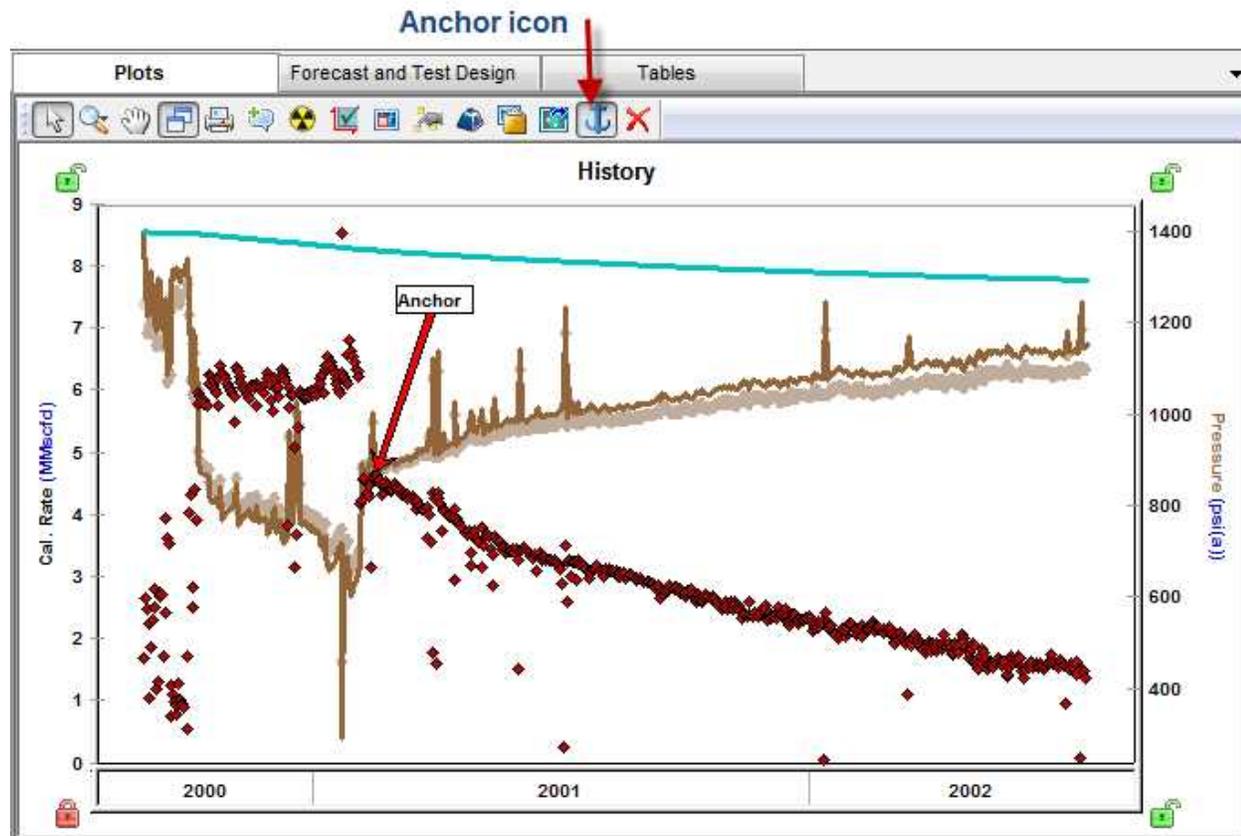
To include dual porosity, click the **Dual Porosity** checkbox in the Analytical Model pane.

For more information, see [dual porosity theory](#).

Anchoring

Anchoring is a technique for improving the efficiency of the history-matching process when the initial pressure is unknown. You can specify a measured pressure and Harmony Enterprise calculates the initial synthetic pressure, which results in the model's analysis line going through that specified pressure. This specified measured pressure is known as the anchor point.

To add an anchor point, click the **Anchor** icon on the History Plot toolbar of any analytical model.



Clicking the Anchor icon automatically places an anchor arrow on the first-measured pressure. In addition, the mouse pointer changes to an anchor, so that you can relocate the anchor from the default position by clicking any measured pressure on the history plot. The anchor point is annotated with an arrow, and if you change the position of the anchor arrow, the model automatically recalculates.

When anchoring is enabled, the initial pressure is calculated and the input cell is read-only. When anchoring is disabled, the initial pressure cell is editable.

Note: The Anchor option is currently only available for analytical models in Calculate Pressure mode.

Injection

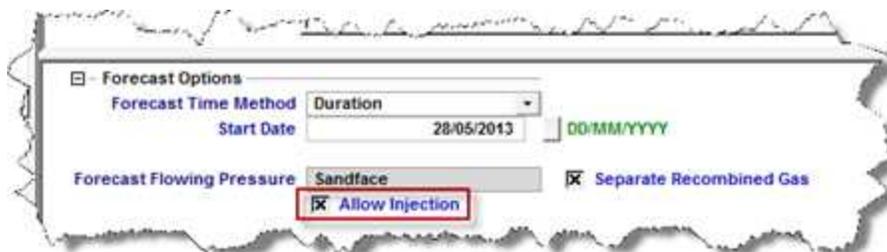
Analytical models can be used to simulate injection. To history match data from a well that has production as well as injection, import both the production and injection data (see [get well data into Harmony Enterprise](#)) into the Production editor.

Start Date	End Date	Gas Volume	Gas Inj Volume	Run Depth Pressure	Active Pressure	Pressure Source	Calc Pres
DD/MM/YYYY	DD/MM/YYYY	MMscf	MMscf	psi(a)	psi(a)		
29/05/2013	30/05/2013	1.199	0.000	4679.29	4679.29	Run Depth Pressure	
30/05/2013	31/05/2013	1.199	0.000	4687.06	4687.06	Run Depth Pressure	
31/05/2013	01/06/2013	1.199	0.000	4697.88	4697.88	Run Depth Pressure	
01/06/2013	02/06/2013	1.199	0.000	4437.11	4437.11	Run Depth Pressure	
02/06/2013	03/06/2013	1.199	0.000	4372.53	4372.53	Run Depth Pressure	
03/06/2013	04/06/2013	1.199	0.000	4312.82	4312.82	Run Depth Pressure	
04/06/2013	05/06/2013	1.199	0.000	4257.08	4257.08	Run Depth Pressure	
05/06/2013	06/06/2013	1.199	0.000	4204.67	4204.67	Run Depth Pressure	
06/06/2013	07/06/2013	1.199	0.000	4155.11	4155.11	Run Depth Pressure	
07/06/2013	08/06/2013	1.199	0.000	4108.00	4108.00	Run Depth Pressure	
08/06/2013	09/06/2013	0.000	1.199	4672.69	4672.69	Run Depth Pressure	
09/06/2013	10/06/2013	0.000	1.199	4812.76	4812.76	Run Depth Pressure	
10/06/2013	11/06/2013	0.000	1.199	4930.83	4930.83	Run Depth Pressure	
11/06/2013	12/06/2013	0.000	1.199	5035.29	5035.29	Run Depth Pressure	
12/06/2013	13/06/2013	0.000	1.199	5129.94	5129.94	Run Depth Pressure	
13/06/2013	14/06/2013	0.000	1.199	5216.99	5216.99	Run Depth Pressure	
14/06/2013	15/06/2013	0.000	1.199	5297.90	5297.90	Run Depth Pressure	
15/06/2013	16/06/2013	0.000	1.199	5373.75	5373.75	Run Depth Pressure	
16/06/2013	17/06/2013	0.000	1.199	5445.30	5445.30	Run Depth Pressure	
17/06/2013	18/06/2013	0.000	1.199	5513.15	5513.15	Run Depth Pressure	
18/06/2013	19/06/2013	0.000	0.000	5239.62	5239.62	Run Depth Pressure	
19/06/2013	20/06/2013	0.000	0.000	5201.60	5201.60	Run Depth Pressure	
20/06/2013	21/06/2013	0.000	0.000	5174.16	5174.16	Run Depth Pressure	
21/06/2013	22/06/2013	0.000	0.000	5152.79	5152.79	Run Depth Pressure	
22/06/2013	23/06/2013	0.000	0.000	5135.51	5135.51	Run Depth Pressure	
23/06/2013	24/06/2013	0.000	0.000	5121.15	5121.15	Run Depth Pressure	
24/06/2013	25/06/2013	0.000	0.000	5109.08	5109.08	Run Depth Pressure	
25/06/2013	26/06/2013	0.000	0.000	5098.77	5098.77	Run Depth Pressure	
26/06/2013	27/06/2013	0.000	0.000	5089.91	5089.91	Run Depth Pressure	
27/06/2013	28/06/2013	0.000	0.000	5082.23	5082.23	Run Depth Pressure	

Both production and injection data are honored by the analytical model. If a certain time period has both production and injection data, Harmony Enterprise calculates the difference between the produced and injected volumes, and this calculated net production is used for modeling.

Running forecasts or test designs is similar for injection and production wells, but for injection wells:

- the Allow Injection checkbox must be selected.



- injection rates are denoted using negative values.

	Time		Control		Sandface Pressure		Gas Rate		
	Step Type	Duration	# of Steps	Interpolation	Control Type	Initial	Final	Initial	Final
		d				ps(a)	pe(a)	MMscfd	MMscfd
1	Arithmetic	20.8	10		Step				
2	Arithmetic				Step				

Note: Since wellhead forecasting is not yet available for injection, if Wellhead is selected from the Forecast Flowing Pressure drop-down list, the Allow Injection checkbox is grayed-out.

Using automatic parameter estimation

Automatic parameter estimation (APE) is used to perform history matching. The steps to do this are: specify the data points to be used, specify the parameters to vary, and run APE.

Specify data points to be used by APE

By default, all data points are selected to be used by APE, except for the points that were filtered out using the filtering option within one of the analyses you created for that well previously. (Filtering can be performed within FMB, unconventional reservoir, or typecurve analyses.) Filtered-out points are treated as outliers, and are not honored by the APE algorithm. These points are displayed in gray in the History plot.

Additionally, you can deselect more data points by clicking the **Tools to Select Data Points for Best Fitting** icon from the History plot toolbar. (Click to select points, and right-click to deselect points.)



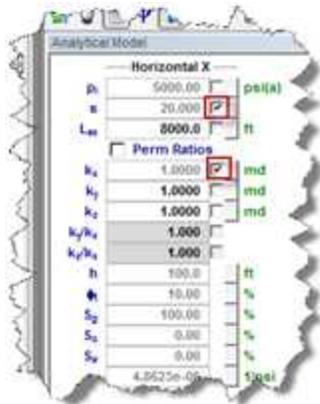
The data points you deselect are not necessarily outliers. They are simply points you do not want to use for history matching in this particular model (for example, if you want to only match the later portion of the production data). Points that are deselected for best fitting are also not honored by the APE algorithm, and are displayed as hollow points (0% weighting) in the History plot.

If it is important to match some specific portion of the data (for example, the last part of the production), you can weight these data points by clicking the **Weight Data Points** icon ().

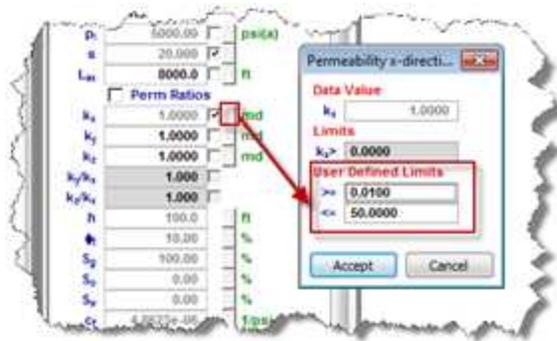
Weighted data points are displayed in a brighter color and are given a 100% weighting. (The weighting is displayed when you hover over the data point.)

Specify parameters to vary

To specify which parameters to vary, click the **Automatically calculate variable** checkbox to the right of the parameter's field.



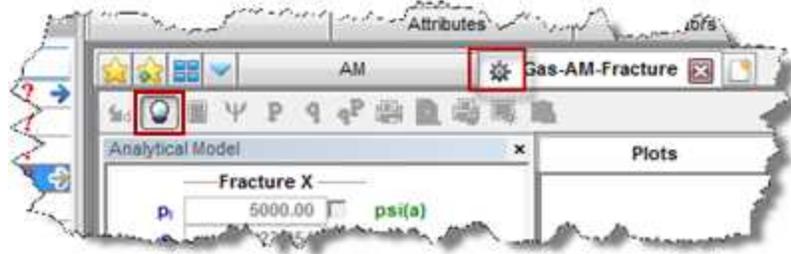
To vary a certain parameter within given limits, click the **View Defaults and Limits** button to the right of the field. Enter the appropriate values, and then click the **Accept** button.



Run APE

To run automatic parameter estimation (APE), click the **APE** icon ().

While APE is running, selected parameters are automatically varied to minimize the error between the simulated pressure and the actual pressure. The updated simulated pressure is shown on the plots right away, and the **Rotating Gear** icon () on the header of the tab indicates that APE is running.



While APE is running, you can wait until it finishes, or if the history match looks good, you can stop the process by clicking the **APE** icon ().

After you have achieved your desired result in CalcP mode, we recommend that you switch to CalcR mode and verify if the calculated rate matches the actual rate. If these rates are not close, additional history matching should be done.

Custom forecast

Custom forecasts are used to bring third-party forecasts into Harmony Enterprise.

Note: This forecast works with your Harmony Forecast™ license.

Custom forecasts are created by importing a third-party forecast (for example, Excel, IHS Piper) for various fluid types into a Forecast worksheet (see analyzing an entity). The files types we support are: .csv, .txt, or .xls / .xlsx.

Only one forecast can be brought in at a time and column headers must be assigned to the data to be imported in the Import Data dialog box, and either a Cumulative Time or Date Time must be specified.

If Date Time is used, the Start and End Dates are read from the import file. The End Date is one day after the last record in the import file for daily forecasts, and one month for monthly forecasts. The End Period can be used to extend the forecast past the final date in the import file by a specified number of days.

The dialog box is titled "Import - Support for Date Time" and contains the following fields and options:

- Instruction: "Please specify an **End Date** (or End Period) for this time-track."
- Start Date: 2016/02/01 00:00:00 (format: YYYY/MM/DD hh:mm:ss)
- End Date: 2073/12/01 00:00:00 (format: YYYY/MM/DD hh:mm:ss)
- End Period: 30.0 (format: d)
- Buttons: OK, Cancel

If Cumulative Time is used, a Start and End Date can be specified. If the host entity contains production data, the Start Date defaults to the end-of-production. If the host entity does not contain production data, the Start Date defaults to midnight of the current day on the machine that is running Harmony Enterprise.

Changing the Start Date changes the End Date, but changing the End Date results in the forecast being truncated or extended.

The End Period can be used to extend the forecast past the final date in the import file by a specified number of months.

The dialog box is titled "Import - Support for Cumulative Time" and contains the following fields and options:

- Instruction: "The system has detected that the custom forecast(s) that you selected for import contains a cumulative time-track. Please specify a **Start Date** and **End Date** (or End Period) for this time-track."
- Start Date: 2016/05/02 00:00:00 (format: YYYY/MM/DD hh:mm:ss)
- End Date: 2074/03/03 04:30:00 (format: YYYY/MM/DD hh:mm:ss)
- End Period: 1.0 (format: month)
- Buttons: OK, Cancel

Decline analysis

The decline analysis uses the conventional Arps' decline method and generates forecasts of future production rates, and the estimated ultimate recovery (EUR) of reserves. For additional information on theory and concepts, see [decline analysis theory](#). When you add a decline analysis (see [analyzing an entity](#)), Harmony Enterprise automatically selects the best subset of your data (90% of your data points) for an initial best fit.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

After you add your decline analysis, the selected analysis (highlighted in purple) has its detailed parameters displayed in the Analysis Parameters pane located below the [Analysis Manager pane](#) (the default setting).

The screenshot shows two panes from the Harmony Enterprise software. The top pane is the 'Analysis Manager' window, which contains a tree view with 'Analysis 1' and 'Analysis 2'. Under 'Analysis 2', there is a table of parameters:

Classification		
EUR ₀	0.366	Mstb
N _p	0.366	Mstb
RR ₀	0.000	Mstb

Below this table, there is a checked checkbox for 'Oil - Decline (RT)'. The bottom pane is the 'Analysis Parameters' window, which displays the following parameters:

Rate Type	Op. Day
Forecast Start Date	02/05/2001
q	0.4
d sec	79.898
b	0.000
R ² _{log q vs t}	-0.160

Harmony Enterprise automatically fits (best fits) your decline curve based on:

- recent trends.
- rate data. It is able to handle shut-ins, and exclude these data points from the best fit.
- If you have anomalies in your data, a local outlier factor algorithm is used to determine which data points are considered outliers to be excluded from the initial best fit.

In order for the auto-fit algorithm to work, at least six months of data is required. If there is not enough data, all of the data points are selected, and a decline curve is generated based on the data that is available. Harmony Enterprise automatically selects the best subset of your data for an initial best fit.

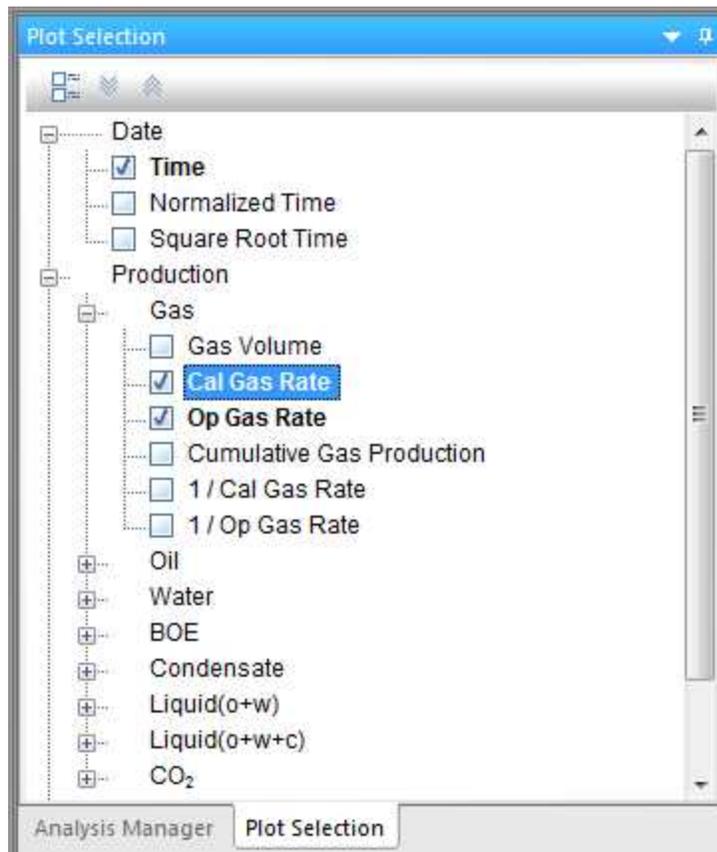
In this pane, you can specify / view the following settings and parameters:

(The parameters that are displayed depend on if the analysis was created on a rate-time (RT), rate-cumulative (RC), or cumulative-time (CT) production plot.)

- **Rate Type** — select calendar rate (**Cal. Day**) or operator rate (**Op. Day**) from the drop-down list. For more information, see [rate type](#).
- **Forecast Start Date** — the decline curve in Harmony Enterprise includes a "best fit" of historical data followed by a forecast section. The Forecast Start Date (FSD), highlighted by a small green triangle, defines the beginning of the forecast. For more information, see [forecast start date](#).
- **q** — the production rate at the *FSD*.
- **d_{sec}** — the effective decline rate at the *FSD*. It can be toggled to d_{tan} , or a nominal decline rate.
- **b** — the decline exponent at the *FSD*.
- **R²** — an indication of the precision of the history match. It is reported as $R^2_{log q vs t}$ on a rate-time (RT) plot, $R^2_{q vs Q}$ on a rate-cumulative (RC) plot, or as $R^2_{Q vs. t}$ on a cumulative-time (CT) production plot.

Rate type

The rate type can be either calendar rate or operated rate, which you can select from the drop-down list at the top of Analysis Parameters pane. However, you first need to select the rate type you want from the Plot Selection tab, which is located next to the Analysis Manager tab (by default).



Note that if you select both the *calendar rate* (for example, *Cal Gas Rate*) and *operated rate* (for example, *Op Gas Rate*), they appear as separate axes on your plot. After you select the rate type to place your decline analysis on, the decline curve is placed on that rate history. The decline parameters do not change, but the precision of your match, indicated by R^2 , does consequently change. Also, the point selection tool for best-fitting () is only active on the selected axis.



Forecast start date

The forecast start date (FSD) defaults to the last data point in the production history (or the active reference date, if it is set to an earlier time). However, you can change this date, which updates the corresponding rate (q), effective decline rate (d_{sec}), and the decline exponent (b) reported below that date.

Multiple segments

You can add multiple segments (see analysis parameters toolbar) to your decline analysis, and under each segment, you can change parameters and the calculation method for that segment.

Segment 1		
Calc Method	Δt Q_r	
Start Date	03/21/2007	MM/DD/YYYY
q_i	134.9	Mscfd
Δt	85.674	month
d_i sec	32.127	%/year
b	0.800	
q_r	27.2	Mscfd
End Date	05/10/2014	MM/DD/YYYY
Q_r	165.493	MMscf

Under each segment's tab, you can specify / view the following parameters:

- **Calc Method** — select the decline parameters you want to enter as inputs, and the parameters to be calculated by Harmony Enterprise. For more information, see [decline calculation methods](#).
- **Start Date** — sets the onset of the decline in a segment. For the first segment, it is defined by the time of the historical (best fit) portion when the decline curve begins.
 - In each best fit of production data, the *Start Date* defaults to the first selected point, and is highlighted by a small blue square. By default, Harmony Enterprise selects the last 50% of the data for curve-fitting, but you can change this percentage by clicking the **Point Selection Tool** icon ().
- q_i — the initial production rate and is reported / specified at the *Start Date*.
- d_i sec — the initial effective decline rate and is reported / specified at the *Start Date*. You can toggle this parameter to show either $d_{i\ tan}$ or a_i (nominal decline rate).
- Δt — the duration of the decline segment.
- q_f — the final forecast rate (abandonment rate), and is initialized from the settings defined in the Options dialog box (see [decline options](#)). However, you can manually modify this rate by entering a new value. When a decline is added to a group, the abandonment rate uses the value in the Options dialog box multiplied by the number of producing wells.
- b — the decline component. The initially reported b value results from the best fit of the selected historical data to a hyperbolic decline, unless a fixed b value is defined in the Options dialog box.
 - The b value can be automatically updated each time you change the historical portion of the fit, if you have the yellow lock icon () open. If

this icon is in a locked position () , your b value is locked and changing the selected history does not impact the reported b value.

- **d_{lim} Date** — if you select one of the three d_{lim} Calc Methods, this field is displayed. This date corresponds to when the decline transitions from a hyperbolic decline to an exponential one.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following key icons:

-  **Show / Hide Results Line** — shows (default setting) or hides the dashed line on the plot that represents the abandonment rate for the decline analysis and the d_{lim} transition.
-  **Add / Remove Segment** — adds a new segment to the end of the existing decline forecast, or removes the last segment. When you add a new segment, this is how Harmony Enterprise *initializes* that segment:
 - **Nominal decline rate (a)** — the beginning of the new segment and the end of preceding segment are equal.
 - q_i of the new segment is set to q_f of the preceding segment.
 - The b value of the new segment is the same as that of the preceding segment, and a duration of *60 months* is initially applied.
-  **Fit Decline to Forecast and Selected Production Points** — clears your historical data selections (the decline "best fit") and uses the data points for the forecast you select. Any additional points you manually select are included in the "best fit" as well. If you select None from the drop-down list, your forecast data is not included in best fits.

Tip: This option works on these forecast types: stretched, Duong, WOR total fluid, custom, ratio, typecurve, analytical, numerical, and the unconventional reservoir module (URM). When best-fitting data, you can control when the b value (slope) should be minimized. For more information, see [b value minimization](#) in the [Options dialog box](#).

-  **Reinitialize Segment** — for reinitialization of a segment, you can select one of the following options from the drop-down menu:
 - **Reinitialize Segment** — the *nominal decline rate (a)* at the beginning of a new segment and end of its preceding segment are set to be equal to ensure there is a smooth transition between the two segments. Also, q_i

of the new segment, and q_f of the preceding segment, are set to be equal. If you have more than two segments, this reinitialization rule applies to all of the segments.

- **Reinitialize Segment q_i** — only the q_i of new segments, and the q_f of their preceding segments, are set to be equal to attach the segments together.
-  **Reset decline to initial state** — resets the plot to the default best fit (initial auto fit). Note that if you changed the dlim Exp field in the Options dialog box, clicking this icon resets the plot to the current value in this field.

Decline calculation methods

After you have created your decline analysis, you can modify the parameters by entering new values. As the parameters are changed, calculated values and the forecast line on the plot are updated. To change which parameters are specified, you can change your *calc method*.

The table below lists which values are specified (denoted by S), and which are calculated (denoted by C), in different calc methods. For special parameters or calc methods, some parameters are marked as not applicable (n/a).

Calc Method	q_i	Δt	d_i	b	q_f	Q_f	dlim
Δt Q_f	S	C	S	S	S	C	n/a
Δt d_i	S	C	C	S	S	S	n/a
Δt q_f	S	C	S	S	C	S	n/a
q_f Q_f	S	S	S	S	C	C	n/a
d_i Q_f	S	S	C	S	S	C	n/a
d_i q_f	S	S	C	S	C	S	n/a
d_i b	S	S	C	C	S	S	n/a
Fixed Rate	S	S	n/a	n/a	n/a	C	n/a
dlim - Δt Q_f	S	C	S	S	S	C	S

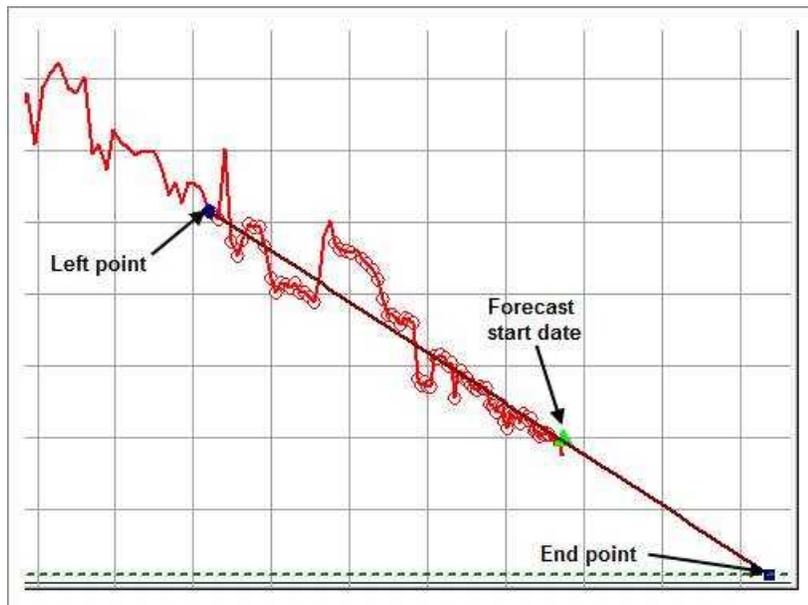
dlim - qf Qf	S	S	S	S	C	C	S
dlim - Δt qf	S	C	S	S	C	S	S
Inclining Rate	S	C	S	n/a	S	C	n/a

- **Fixed rate** — this calculation method can be used to create a constant rate forecast. When you switch to this *calc method*, the previous q_i and Δt are maintained. These are the only parameters that can be changed for this forecast type.
- **d_{lim}** — when a decline forecast has a b value greater than 0, the decline rate (or slope at a given point on the curve) decreases through time. The decline rate can become very small, resulting in a very long forecast and sometimes an unreasonable EUR. The d_{lim} calc method provides a way to limit this by setting a minimum decline rate (d_{lim}). After this minimum decline rate is reached, the forecast proceeds with a b of 0 (a constant decline rate, or exponential decline), and a vertical dashed-green line displays the transition between the two decline regimes.
 - The limiting effective decline rate can be toggled between exponential ($d_{lim\ exp}$) and hyperbolic ($d_{lim\ hyp}$). This defines whether the nominal decline rate (at the time of transition from the hyperbolic decline to the exponential decline) should be calculated using the b value of the hyperbolic, or exponential decline regimes.
- **Inclining rate** — this method can be used to create a segment with an increasing rate. The b value is forced to remain at 0. The q_i , d , and q_f are specified. By default, when you switch to this *calc method*, the q_i is maintained, and the d_i is converted to a negative value (an inclining rate rather than a declining rate). A q_f is initially calculated to set the Δt to 60 months.

Line manipulation

Line manipulations are initiated by clicking (sometimes while pressing the **Ctrl** or **Shift** keys) the line itself, or one of the manipulation points for a given segment (start date, forecast start date, or end date). You can cancel your line manipulation by pressing the **Esc** key. Specific line manipulations are described below.

Tip: Any time you see "click", this means to left-click your mouse. Right-click actions are specifically mentioned.



Left point: any historical point (The selection between the left point and the FSD is not included in the forecast; it is only used to show historical production.)
Forecast start date (FSD): the middle point of the line
End point: the expected ultimate recovery

- **Forecast Start Date, FSD** (indicated by a green triangle on the decline line)
 - **Click, grab-and-drag** — maintains the shape of the decline line and the b and d values. Enables vertical shifting of the decline line, which results in changes to q and q_i .
 - The segments after the segment containing the FSD are also affected because they are shifting in time / cumulative production.
 - **Shift key** — pressing the **Shift** key while dragging enables you to position the FSD along the decline curve, while maintaining the shape of the decline. This changes your Q_f (only on a rate-time Decline

worksheet).

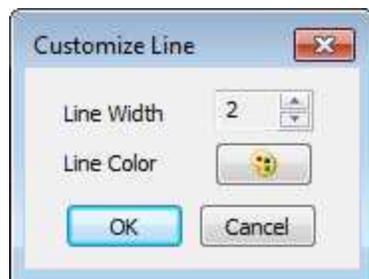
- Positioning of the FSD beyond the historical production is restricted on a rate-cumulative (RC) production decline.

- **Ctrl key** — pressing the **Ctrl** key while dragging enables horizontal shifting (translation) of the decline with time. This impacts the FSD in time on a rate-time (RT) plot, but the decline parameters remain unchanged.
 - If the *FSD* is located on the second segment, pressing the **Ctrl** key results in behavior similar to "click, grab-and-drag" on the second segment.
- **Start Date** (indicated by a blue circle)
 - **Click, grab-and-drag** — moves the decline line vertically to change the q_i of the segment. However, it does not change the *start date* or *FSD*. The shape of the decline (b and d) line is preserved.
 - Both q_i and q for the segment being manipulated get modified, and all segments following this segment are shifted in time / cumulative production, accordingly.
 - **Shift key** — pressing the **Shift** key while dragging extends your forecast back into the historical production. The *start date*, q_i , and d_i change, but the b value is not impacted.
 - This Shift-key functionality does not apply to a *secondary* segment.
 - **Ctrl key** — pressing the **Ctrl** key while dragging translates the curve along the x-axis. The *start date*, *FSD*, and *forecast end date* advance in time for the first segment.
 - This Ctrl-key functionality does not apply to a *secondary* segment.
- **End Date** (indicated by a blue square)
 - **Click, grab-and-drag** — enables you to move the *end date* in time, anchoring to the start date and maintaining the q_f . The b value is maintained, but d_i is updated. If the FSD is contained within the segment, then q and d update as well.

- **Shift key** — pressing the **Shift** key while dragging extends your forecast forward in time, and decreases your final rate (q_f). Your final Q_f increases, but none of the decline parameters change.
- **Ctrl key** — visually similar to the grab-and-drag functionality for the end date, but the b value can change with the Ctrl-key functionality.
- **Any point on the forecast decline curve** (activated when the decline segment turns orange)
 - **Click, grab-and-drag** — If the segment contains the FSD, that segment is anchored to the *FSD* and rotates around while the b value and q_f are maintained.
 - On a segment that does not contain FSD, the decline is anchored to the *start date* of the segment.
 - If you accidentally place the FSD at the end date of a segment, the decline is anchored to the *end date* of the segment.
 - **Ctrl key** — the curvature of the line (the b value) changes.

Decline-line customization

You can customize the width and color of your decline line / curve by right-clicking it.



After you customize your decline line / curve, the modifications are saved and applied to every worksheet that displays this decline.

Duong decline analysis

The Duong analysis was developed specifically for unconventional reservoirs with very low permeability. For more information, see [Duong decline theory](#).

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

After you add your decline analysis (see [analyzing an entity](#)), the selected analysis (highlighted in purple) has its detailed parameters displayed in the Analysis Parameters pane located below the Analysis Manager pane (the default setting).

The screenshot shows the 'Analysis Manager' pane at the top, which contains a table of analysis parameters. Below it is the 'Analysis Parameters' pane, which displays detailed settings for the selected analysis.

Analysis Manager		
Analysis 1		
EUR ₀	14.981	Mstb
N _p	0.615	Mstb
RR ₀	14.367	Mstb
<input checked="" type="checkbox"/> Oil - Duong (RT)		

Analysis Parameters		
Rate Type	Op. Day	
Calc Method	Δt	
Start Date	05/01/2010	MM/DD/YYYY
q _i	0.7	stb/d
Δt	6000.000	month
a	0.500	/d
m	1.100	
q ₁	443.1	stb/d
q _∞	0.0	stb/d
q _r	0.0	stb/d
End Date	05/05/2510	MM/DD/YYYY
Q _r	14.981	Mstb
R ² _{log q vs t}	-0.145	

In this pane, you can specify / view the following settings and parameters:
(The parameters that are displayed depend on if the analysis was created on a rate-time (RT) or rate-cumulative (RC) production plot.)

- **Rate Type** — select calendar rate (**Cal. Day**) or operator rate (**Op. Day**) from the drop-down list. For more information, see [decline analysis: rate type](#).
- **Calc Method** — select the method by which the decline analysis is calculated (for example, Δt or q_f) from the drop-down list.
- **Start Date** — the end of production data and the date of the forecast start, represented by the middle point of the analysis line.
- q_i — the initial gas / oil production rate for the forecast.
- Δt — the duration of the decline segment.
- $t_{(a,m)}$ — the time function based on the coefficients a and m .
- t_{max} — the time at which the maximum flow rate occurs.
- a — the straight-line intercept of a $\log(q/N)$ vs. $\log(t)$ plot.
- m — the negative of a straight-line slope of a $\log(q/N)$ vs. $\log(t)$ plot.
- q_t — rate.
- Q_t — cumulative.
- q_1 — the rate at day one estimated from the slope of a plot of q vs. $t_{(a,m)}$.
- q_∞ — the rate at infinite time estimated from the intercept of a plot of q vs. $t_{(a,m)}$.
- q_f — the gas / oil production rate at the end of the forecast.
- q_{max} — the maximum flow rate.
- **End Date** — the date the forecast ends.
- Q_f — the cumulative production at the end of the forecast — expected ultimate recovery (EUR).
- R^2 — an indication of the precision of the history match. It is reported as $R^2_{\log q \text{ vs } t}$ on a rate-time (RT) plot, and $R^2_{q \text{ vs } Q}$ on a rate-cumulative (RC) production plot.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following icon:



Show / Hide Results Line — shows (default setting) or hides the dashed-green line on the plot that represents the abandonment for the stretched decline analysis..

Line manipulation

Line manipulations are initiated by clicking (sometimes while pressing the **Ctrl** or **Shift** keys) the line itself, or one of the manipulation points for a given segment (start date, forecast start date, or end date). You can cancel your line manipulation by pressing the **Esc** key. Specific line manipulations are described below:

Tip: Any time you see "click", this means to left-click your mouse. Right-click actions are specifically mentioned.

- **Start Date** (indicated by a blue circle)
 - **Click, grab-and-drag** — moves the decline line vertically to change the q_i of the segment. However, it does not change the *start date* or *Forecast Start Date (FSD)*. The shape of the decline (b and d) line is preserved.
 - Both q_i and q for the segment being manipulated get modified, and all segments following this segment are shifted in time / cumulative production, accordingly.
 - **Shift key** — pressing the **Shift** key while dragging extends your forecast back into the historical production. The *start date*, q_i , and d_i change, but the b value is not impacted.
 - This Shift-key functionality does not apply to a *secondary* segment.
 - **Ctrl key** — pressing the **Ctrl** key while dragging translates the curve along the x-axis. The *start date*, *FSD*, and *forecast end date* advance in time for the first segment.
 - This Ctrl-key functionality does not apply to a *secondary* segment.
- **End Date** (indicated by a blue square)
 - **Click, grab-and-drag** — enables you to move the *end date* in time, anchoring to the start date and maintaining the q_f . The b value is maintained, but d_i is updated. If the FSD is contained within the segment, then q and d update as well.
 - **Shift key** — pressing the **Shift** key while dragging extends your forecast forward in time, and decreases your final rate (q_f). Your final Q_f increases, but none of the decline parameters change.
 - **Ctrl key** — visually similar to the grab-and-drag functionality for the end date, but the b value can change with the Ctrl-key functionality.
- **Any point on the forecast decline curve** (activated when the decline segment turns orange)

- **Click, grab-and-drag** — If the segment contains the FSD, that segment is anchored to the *FSD* and rotates around while the *b* value and q_f are maintained.
 - On a segment that does not contain FSD, the decline is anchored to the *start date* of the segment.
 - If you accidentally place the FSD at the end date of a segment, the decline is anchored to the *end date* of the segment.
- **Ctrl key** — the curvature of the line (the *b* value) changes.

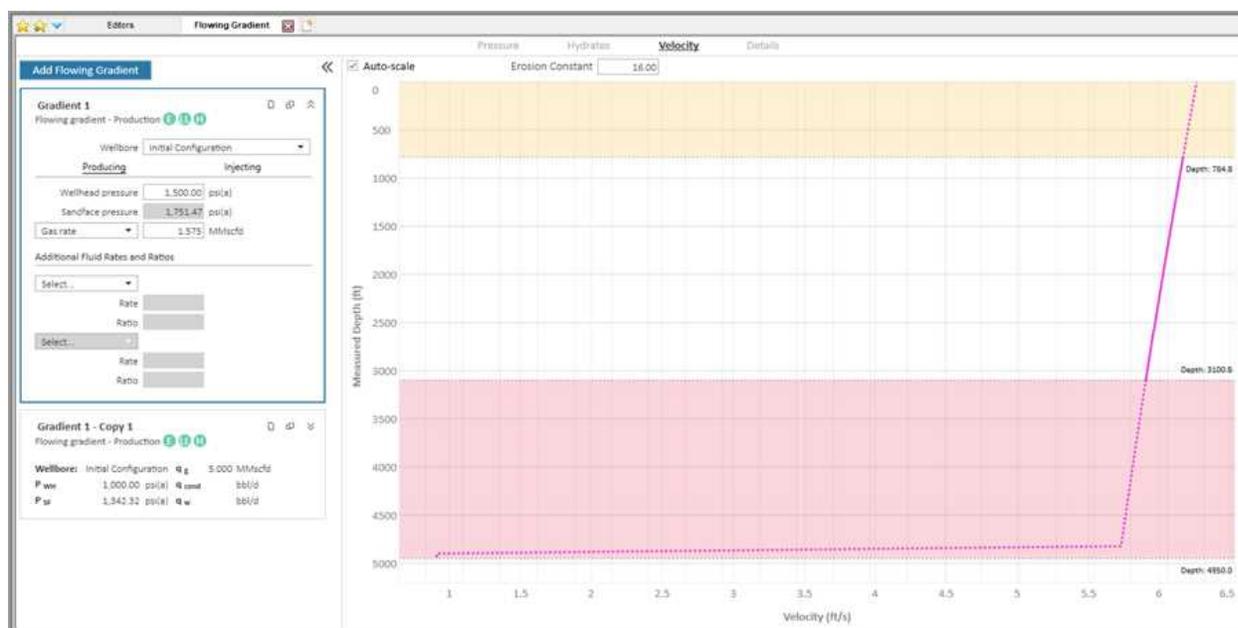
To customize your line, right-click it. For more information, see [decline-line customization](#).

Flowing Gradient

Based on the selected wellbore configuration, you can calculate and plot the pressure drop and other parameters as gradients in the wellbore. With this information, you can mitigate liquid loading, erosion, and hydrate formation by changing the wellbore configuration or operating conditions. You can also decide upon the best wellbore configuration for a well based on the flow rates.

Note: This analysis works with your Harmony Optimize™ license.

Click to show / hide an example screenshot



-  **Delete** — removes the currently selected inflow, outflow, gradient, or forecast.
-  **Copy** — creates a duplicate of the currently selected inflow, outflow, gradient, or forecast. The name is appended with the word "Copy".
-  /  **Show / Hide** — toggle between showing or hiding the inflow, outflow, gradient, or forecast.
-  /  **Collapse / Expand** — closes / opens the details for the inflow, outflow, gradient, or forecast. If you see a red triangle () in the top left of a collapsed analysis, you need to investigate the required parameters.

The analysis includes the following functionality:

- **Add Flowing Gradient** button — click this button to calculate the pressure drop in a wellbore in the Gradient box. Toggle between **Producing** and **Injecting** mode. Circular alerts in the Gradient section notify you of risk factors with the selected gradient [erosion (E), hydrates (H), liquid loading (LL)].
- **Pressure** header — displays a plot of flowing pressure gradients along the wellbore.
- **Hydrates** header — displays a plot of temperature and pressure gradients along the wellbore, as well as regions where hydrates may form. If this header has a red dot beside it, this indicates that your data may require further analysis.
- **Velocity** header — displays a plot of fluid velocity gradients along the wellbore, as well as regions affected by liquid loading or erosion.
- **Details** header — displays a comprehensive data table. Click the options in Parameters you want displayed.

Pressure header

In this section, you can view pressure gradients.

For the currently selected gradient, pressure is plotted versus depth. If there are multiple gradients, then the active gradient is displayed in blue and other gradients in gray. When you hover over a gradient, its name is displayed.

Note: Injection calculations use the same correlations as production calculations. While this is fine for single-phase flow, it may be a problem for multiphase flow because the correlations may not have been designed for downwards flow.

Hydrates header

In this section, you can view your risk factors for hydrates forming.

For the currently selected gradient, pressure and temperature are plotted versus depth. Regions affected by the formation of hydrates are shaded in light blue, and the pressure and temperature are dotted lines.

Propane content — accepts values between 0-10% propane content by weight.

Velocity header

In this section, you can determine the optimal fluid velocity for your wellbore.

For the currently selected gradient, velocity is plotted versus depth. The solid pink line displays the average fluid velocity at any point along your wellbore. Sometimes you may see shading on the plot:

- the pale yellow shaded region denotes the portions of your wellbore where the fluid velocity is above the erosional velocity threshold.
- the pink shaded region denotes the portion of your wellbore where the fluid velocity is below the liquid loading threshold.

Erosion Constant — sensitize your reservoir's erosional performance through careful adjustment of this constant.

Details header

With this comprehensive table, you can do a deep-dive into the hidden flow parameters for your wellbore. Fluid compositions, PVT properties, pressure losses, and more are available at a segment-by-segment level.

This table is extremely useful for troubleshooting nuanced analyses and the interaction of fluids within the wellbore.

Supported flow paths

This analysis supports most (but not all) of the flow paths available in the Wellbore editor.

Natural flow

The tubing, casing, annulus and both flow paths are supported for single-layer wellbores.

Note: Multilayer wellbores are not supported.

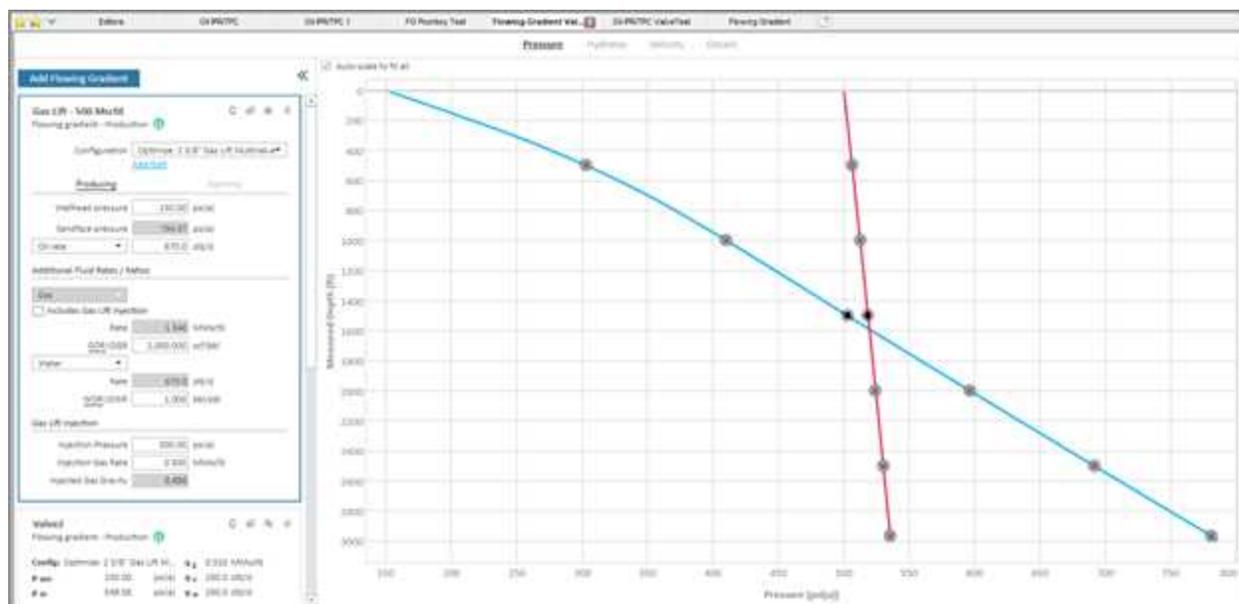
Artificial lift

Flowing gradient supports both Gas Lift and Pumping for Optimize Configurations only.

Gas lift

You can manipulate your production rates and pressures along with your injection rate and pressure to calculate your effective sandface flowing pressure and operating valve. You can generate sensitivities on potential operating conditions in pursuit of maintaining injection through the deepest available valve.

In the screenshot below, a Gas Lift flowing gradient is displayed on the plot. The blue producing-side gradient curve is displayed alongside the red injecting-side gradient curve. Both curves display valve icons at the depths specified in the Optimize wellbore configuration, though only one valve can be considered the operating valve. For more details on each gradient curve's flow parameters, view the Details sub-tab.



Since gas lift is a method that combines both injection and production, then only the "Producing" option is available (the "Injecting" button is grayed-out). However, the Details tab has additional

functionality so that you can show the calculation parameters for either the tubing or annular part of the wellbore.

Pumping

To calculate the flow conditions along your wellbore, type a production rate and a flowing pressure – wellhead, pump intake, or sandface.

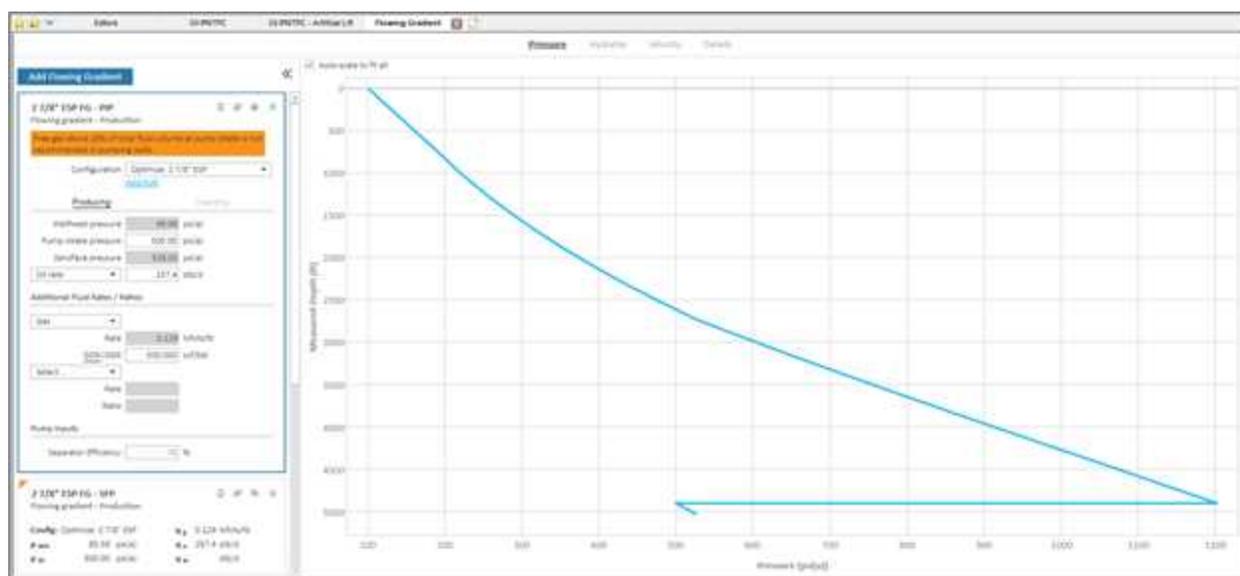
The Flowing Gradient worksheet implicitly accounts for total pressure drop across the pump assembly as a whole as miniscule wellbore segments. This worksheet does not calculate per-stage pressure changes.

As it is common design practice for ESPs to shunt excess free gas through the annulus, we have added a Separator Efficiency input to model this mechanism.

We have added separator efficiency to modify GOR sent through the tubing. The separator efficiency reflects the percentage of free gas at pump conditions removed from the pump flow path (and produced up the annulus). We are doing a direct calculation – the GOR input is assumed to be seen at the pressure reference point provided. If a wellhead (tubing head) pressure is provided, this is the GOR observed flowing through the tubing. If a Pump Intake or Sandface Pressure is provided, this is the total GOR for the well.

If over 20% of the total fluid volume is free gas at pump intake conditions, ESPs can be damaged. Calculations continue, but a warning message is displayed.

In the screenshot below, the wellbore's pump decreases the sandface pressure by about 700 psi. A free-gas warning is displayed on the analysis card stating that the free gas volume fraction at the pump intake exceeds 20%. To alleviate this, you can reduce the GOR or increase the separator efficiency.



FMB analysis

You can use the flowing material balance (FMB) analysis as a practical technique to estimate hydrocarbons-in-place from production rates and pressures. It uses precisely the same principles as a classical material balance analysis, but requires no shut-in data. It is designed for wells that have reached boundary-dominated flow, but can also be used to identify minimum original gas / oil in place (OGIP / OOIP) in transient cases. For additional information, see [FMB theory](#).

After an FMB analysis is created, data points are displayed on the plot. A portion of the data representing boundary-dominated flow should follow a straight line. Locate the analysis line that goes through the boundary-dominated (late) portion of the data. The original fluid in-place (OGIP, OOIP, or OWIP) is calculated based on the position of the analysis line.

Note: This analysis works with your Harmony Reservoir™ license.

If you analyze a group of wells, you can change which well is displayed by selecting your well from the **Primary Well** drop-down list. Note that there is no interpretation for these well completion parameters: skin and fracture half length.

Plot Options

Plot options define which datasets are displayed on the plot.

- **Productivity Index** — plots the productivity index versus Cumulative Gas Production. If the correct OGIP is calculated from the material balance analysis, the productivity index for the boundary-dominated portion of the data should plot as a flat line. A downward sloping line can be an indication that the calculated volume is too large, while an upward sloping line can indicate that the calculated volume is too small. Productivity indexes that fall off a flat line can also be an indication of operational issues with the well. The underlying calculation is described in [productivity index](#).

Note: AG FMB, Flowing p/Z**, and the Productivity Index plots are different ways to display the same set of production data; therefore, the results of these three analyses should be in agreement. That is why the analysis lines for these three plots are linked to each other and always give the same OFIP.

- **Flowing Pressure** — flowing pressure points are not used in the analysis, but can be displayed as a reference.
- **Gas Rate** — gas rates are not used in the analysis, but can be displayed as a reference.
- **C Value** — coefficient values in the simplified absolute open flow (AOF) equation are not used in the analysis, but can be displayed as a reference.

For Oil FMB:

- **Oil FMB** — plots normalized rate versus Normalized Cumulative Production. The underlying calculation is described in [oil theory](#).
- **Static Pressure** — if [static pressures](#) are available, you can use this data as an independent confirmation of the OOIP:
 - in single-phase mode (when the **Multiphase (Pseudo-Pressure)** option is deselected) — static pressure is plotted against

$$\text{Adjusted Normalized Oil Cumulative Production} = \frac{E}{B}$$

A straight line drawn through this data defines OOIP. Estimates of OOIP based on flowing pressures and static pressures should be consistent.

- in multiphase mode (when the **Multiphase (Pseudo-Pressure)** option is selected) — static pressure is plotted against date. If the estimate of OOIP is correct, average pressures are calculated using FMB Model Options / Average Pressures, and static pressures should be consistent.
- **Gas-Oil ratio** — are not used in the analysis, but can be displayed as a reference.

FMB Model Options (Patent Pending)

FMB model options include the following:

- **Oil Rate** — uses the measured flowing pressure to calculate a synthetic oil rate, and compares the synthetic and measured oil rates. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the oil rates is obtained.
- **Flowing Pressure** — uses the measured oil rate to calculate a flowing pressure, and compares the synthetic and measured flowing pressures. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the flowing pressures is obtained.
- **Average Pressure** — uses the measured flowing pressure and the flowing oil rate to calculate a synthetic average reservoir pressure. Modifies the productivity index and the original-oil-in-place, N, until an acceptable history-match of the average pressure is obtained.

Material Balance Options

Material balance options include the following:

- **Multiphase (Pseudo-Pressure)** — accounts for the variation of oil properties with pressure. For more information, see [accounting for changing oil properties](#).
- **Adsorption (for Gas FMB)** — corrects the data to include adsorbed gas. For more information, see [accounting for adsorbed gas-in-place](#).
- **GeoMechanical (for Gas FMB and Oil FMB)** — accounts for the variation in rock properties (permeability and formation compressibility) with pressure. For more information, see [including pressure-dependent permeability and formation compressibility](#).
Note: For the Oil FMB analysis, this option is only available if the Changing Properties (Pseudo-Pressure) option is selected.
- **PSS Water Drive (for Gas FMB and Oil FMB)** — accounts for water drive (additional water drive analysis parameters are displayed). For more information, see [analyzing reservoirs with aquifer support](#).

Calculations

Harmony Enterprise calculates the original fluid in-place based on the position of the analysis line. This value is displayed in the Calculations section, along with some additional parameters.

Calculations		
PI _{gas}	0.530	MMscfd/(10 ⁶ psi ² /cP)
A	179	acres
OGIP _F	2306	MMscf
OGIP _{Rs}	116	MMscf
OGIP	2422	MMscf
G _p	1153	MMscf
EUR _g	1864	MMscf
RR _g	712	MMscf
P _{sb}	109.10	psi(a)
RF _g	77.0	%

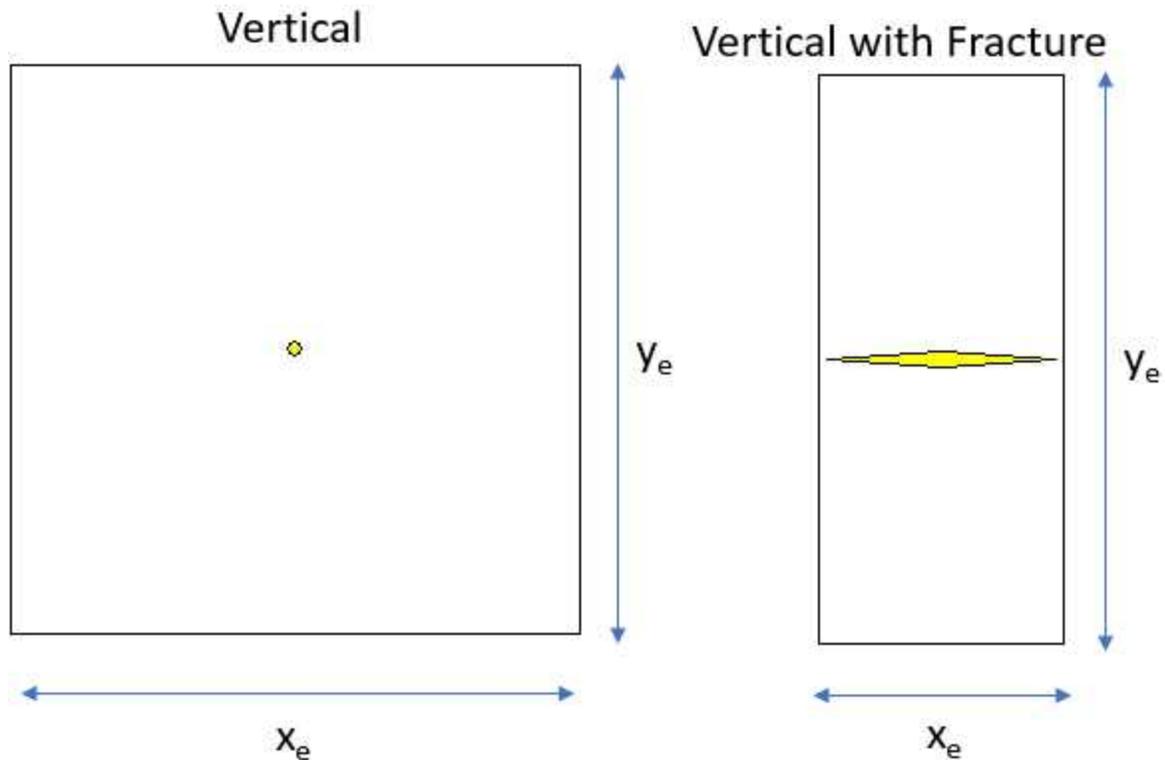
The FMB analysis does not require any assumptions about well and reservoir geometry. However, if you can make an assumption about geometry, reservoir permeability can be calculated based on the productivity index (PI). (PI is defined by the y-intercept of the analyses line.)

Permeability calculation is implemented for two types of geometry:

- Vertical — assumes a vertical well located approximately in the middle of the reservoir.
- Vertical with fracture — assumes a vertical well with fracture, where the fracture is extended approximately throughout the entire width of the reservoir.

To get the value for permeability, select the assumed geometry in the **Model Type** drop-down list.

Note: Permeability calculation is not currently available for multiphase FMB.



Plot toolbar

This toolbar has the following important icons:

-  **Single Annotation** — adds a single annotation to a specific point on your dataset.
-  **Linked Annotations** — synchronizes your annotation across all plots for FMB, URM, and typecurve analyses. For example, if you move your annotation on one plot using the keyboard arrow keys, the arrow is synchronized on the other plots.
-  **Data Filter** — opens the Data Filter dialog box where you can apply a data filter. For more information, see [filtering](#).
-  **Rate Type Option** — select either Calendar Rate or Operated Rate.
-  **Hide / Show Disabled Points** — toggle between hiding and showing data points that have been disabled.

For information on common plot icons, see [plot toolbars](#).

Filtering

If you believe some of the production data points are of poor quality, or are outliers, you can filter them out (disable these points). To do this, click the **Data Filter** icon () in the FMB plot toolbar.

Then, click the **Tools to Select Data Points for Filtering** icon () in the [Data Filter dialog box](#) (opens when you click the Data Filter icon) to select and deselect the data points you want. Click to select points, and right-click to deselect points.

Filtered-out (disabled) points are displayed in gray in the FMB plot. (You can hide these points by clicking the **Hide / Show Disabled Points** icon ().)

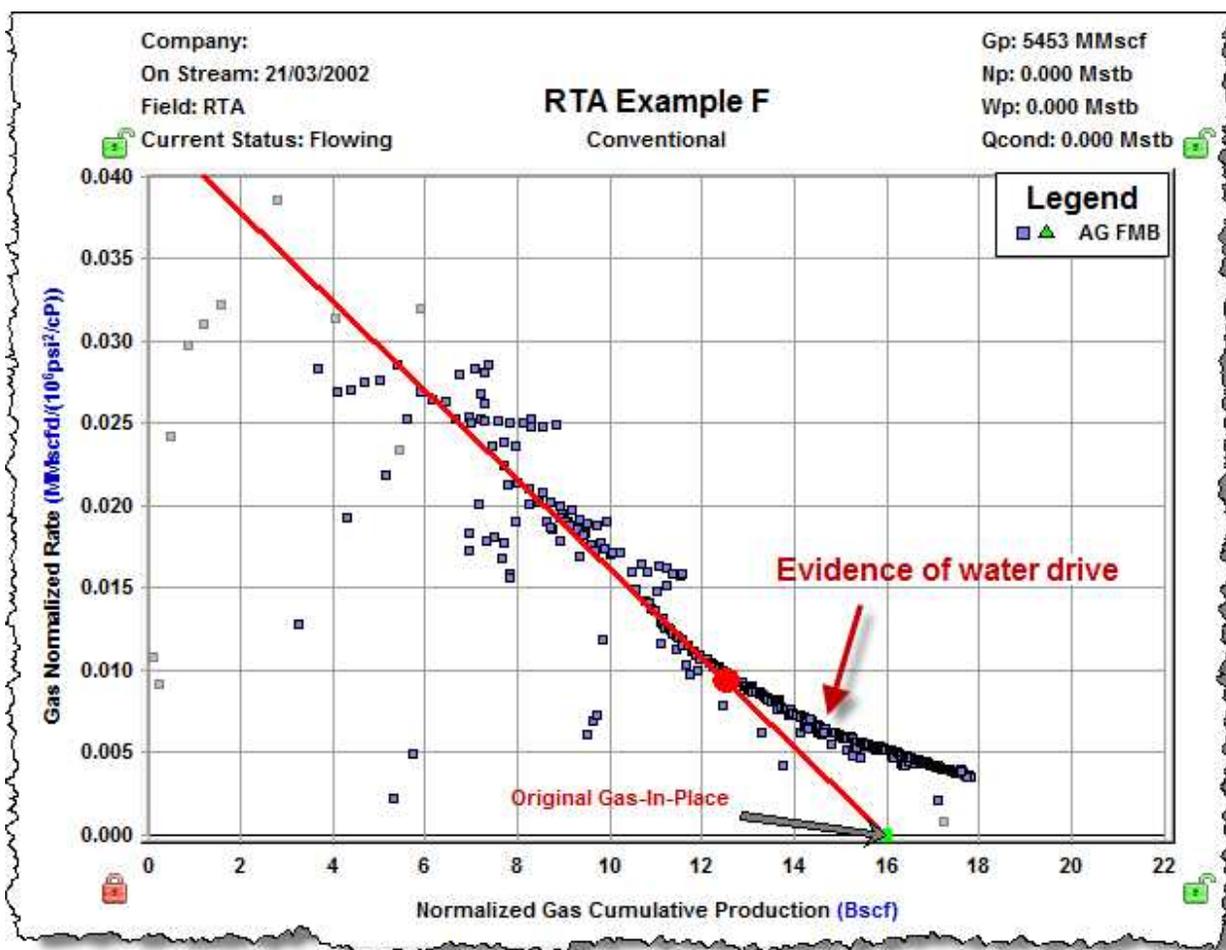
Tip: Selection of filtered-out (disabled) points is shared between all FMB, unconventional reservoir, and typecurve analyses for the same fluid type. In addition, these selections are saved when you export to a local database, or import from a local database.

Best fitting

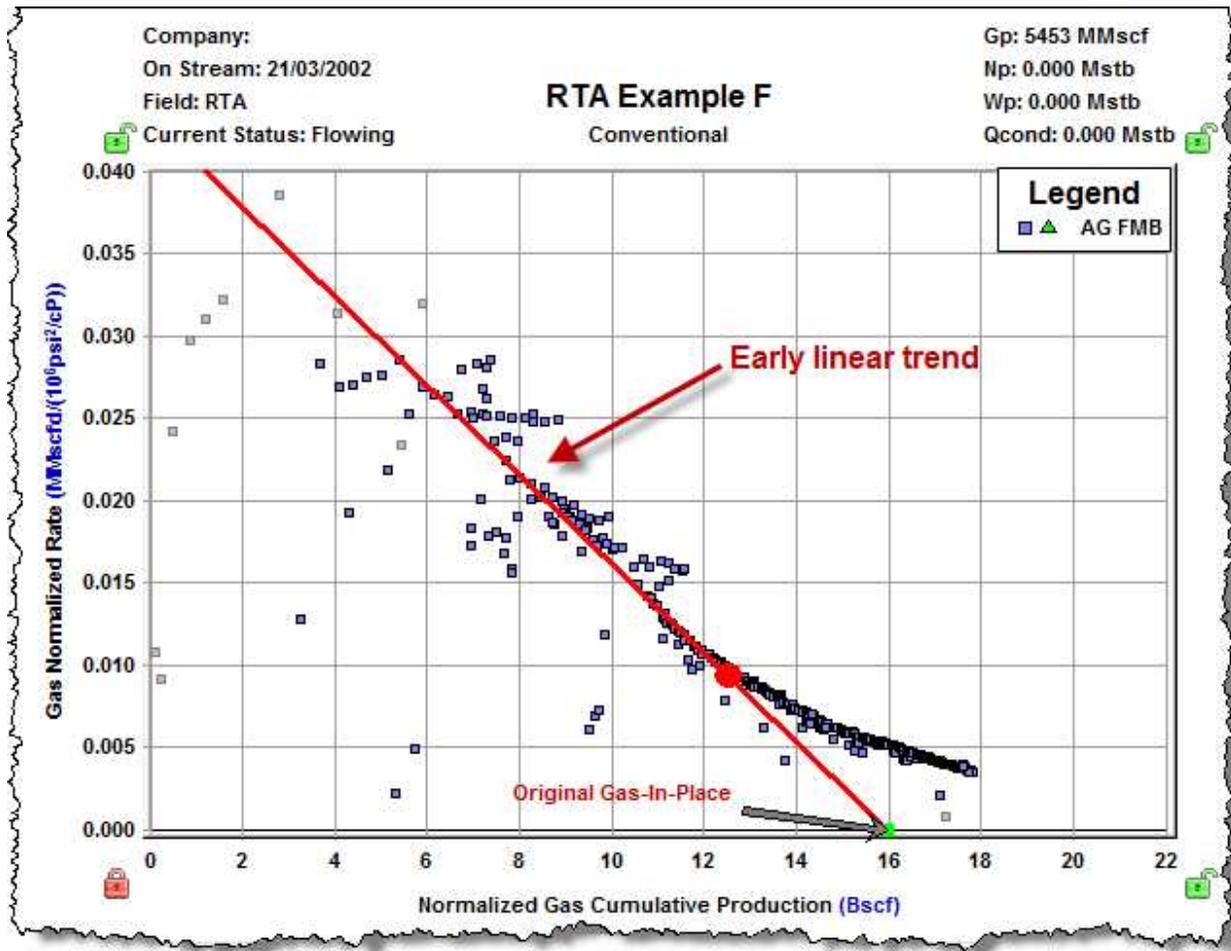
When you use the [spray gun icon](#) () to select data points, you are selecting data points for best fitting (with a normal, or 10% weighting). The analysis line is redrawn to best-fit through the points you selected. If you move the best-fit line (for example, by dragging and dropping), the best-fit selection resets. You can have different selections for best fitting different analysis, and your best-fit selection is saved when you export to a local database, or import from a local database. For more information, see [export data](#) and [import from an .hldb file](#).

Analyzing reservoirs with aquifer support

The flowing material balance (FMB) analysis provides the capability to analyze reservoirs with aquifer support. FMB handles water drive in a similar manner to static material balance. For additional information, see [water-drive reservoir](#). A well displaying water drive tends to display an upward departure from the linear trend later in production when the pressure support from the aquifer begins to have an influence.



Position the analysis line through the straight portion of the early data. It is assumed that aquifer support is not felt until later in production; therefore, the trend of the early data is the true indication of original volume in place.



In the Material Balance Options section, click the **PSS Water Drive** checkbox, which displays the Water Drive Analysis parameters.

Material Balance Options

Adsorption

GeoMechanical

PSS Water Drive

Calculations

PI_{PSS}	0.043	$MMscfd/(10^6 psi^2/cP)$
A	190	acres
OGIP	15969	MMscf
G_p	5453	MMscf
EUR_g	12775	MMscf
RR_g	7322	MMscf
P_{ab}		psi(a)
RF_g	80.0	%

Water Drive Analysis

$OWIP$	222.215	$MMstb$
PI_{Aq}	0.123	$(bbl/d)/psi$

Initial Water in Place

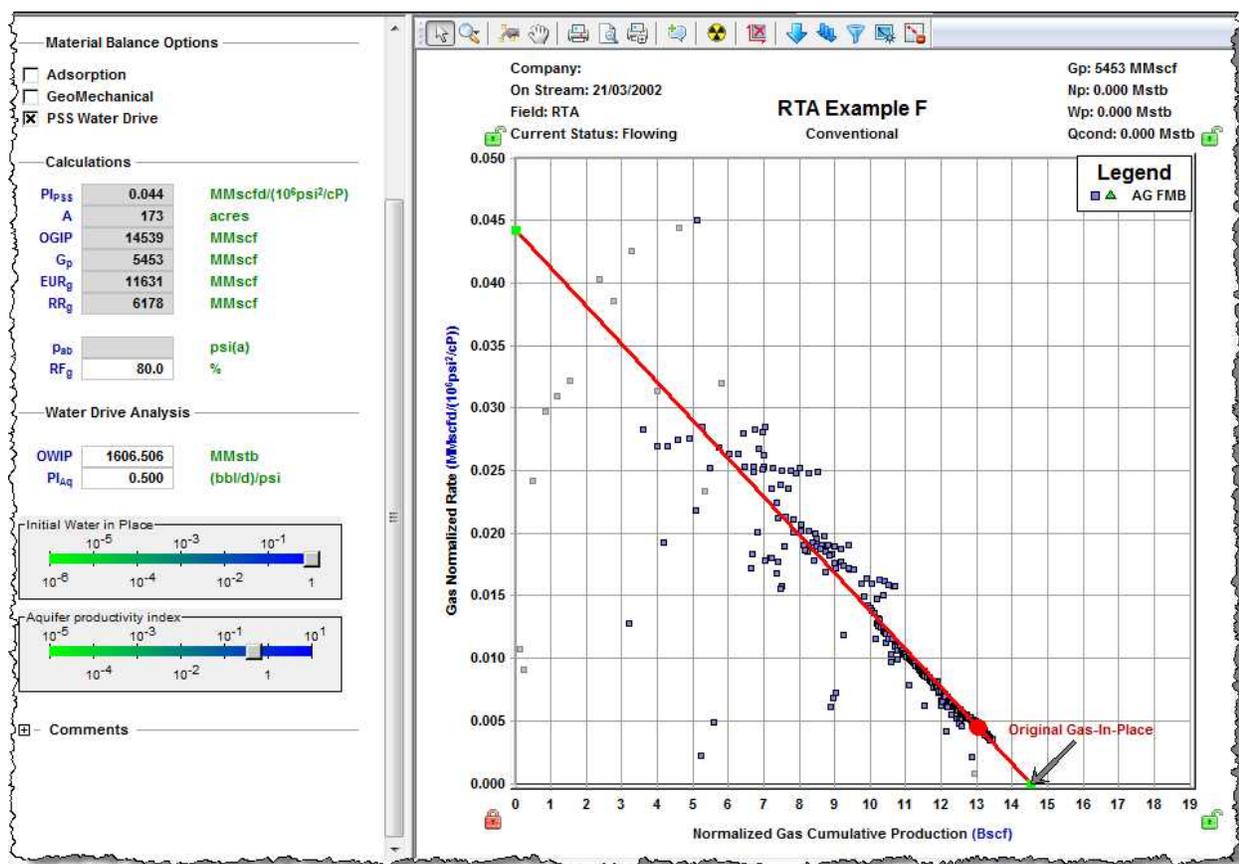
Aquifer productivity index

Adjust the Initial Water in Place and Aquifer productivity index either by entering values into the appropriate fields, or by using the sliderbar.

Note: The limits of the sliderbar can be adjusted by placing the gray slider box at the end of the bar. Then, use your scroll button on your mouse. Double-clicking the gray slider box positions the sliderbar in the middle of the scale.

Continue adjusting both parameters (that is, Initial Water in Place and Aquifer productivity index) until the production data becomes a straight line.

Important: The results of this analysis are not unique, because many different combinations of OWIP, OGIP, and the productivity index can result in a linear trend.



Including pressure-dependent permeability and formation compressibility

The flowing material balance (FMB) analysis provides the capability to include pressure-dependent permeability and rock compressibility in the analysis.

In the Plot Options section, click the **AG FMB** checkbox.

In the Material Balance Options section, click the **GeoMechanical** checkbox. This enables the geomechanical correction (see [geomechanical reservoir models](#)), which uses inputs from the [Properties editor](#) (under Formation / Rock Properties -> Geomechanical).

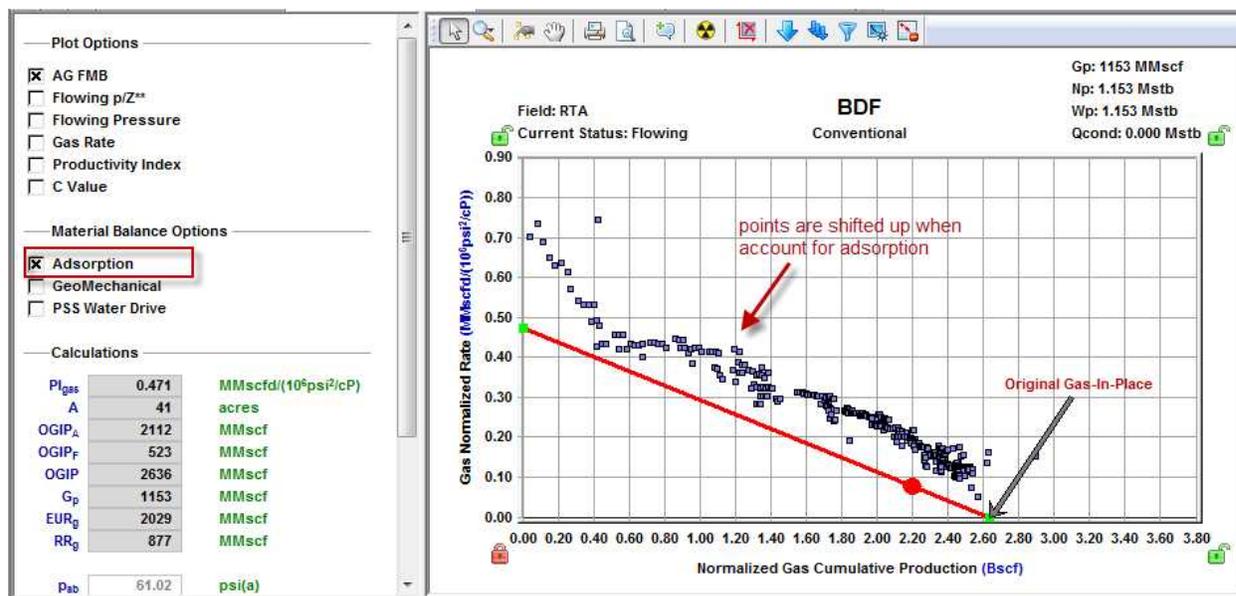
Note: For the Oil FMB analysis, this option is only available if the Changing Properties (Pseudo-Pressure) option is selected.

Accounting for adsorbed gas-in-place for shale gas plays

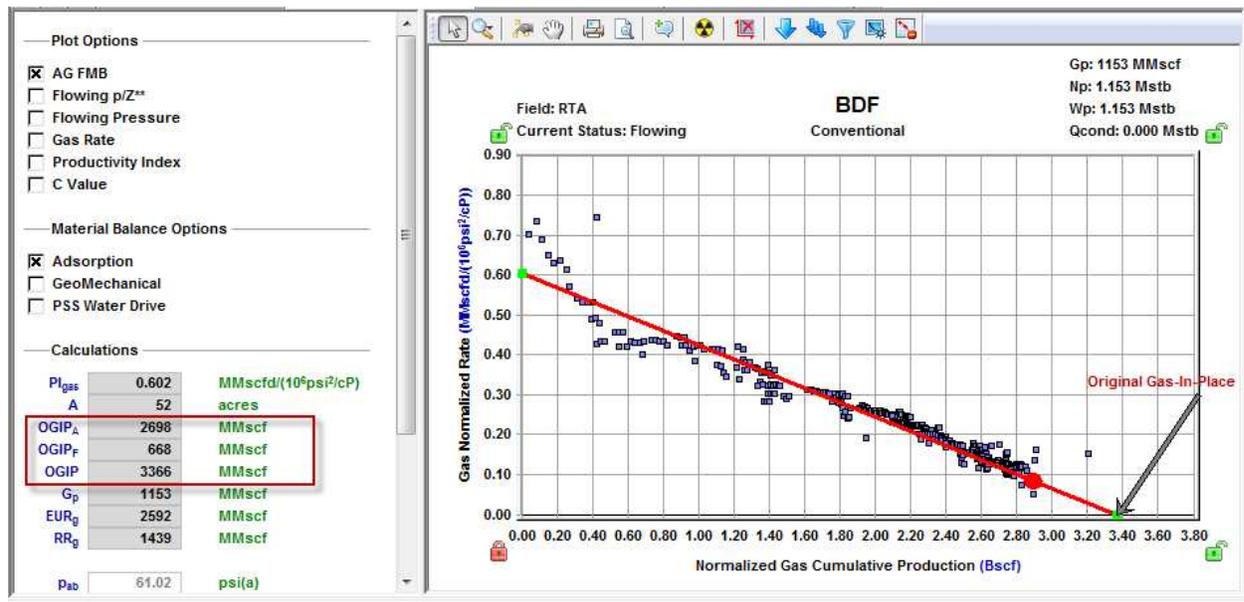
The flowing material balance (FMB) analysis provides the capability to account for adsorbed gas-in-place (GIP) for shale gas plays.

In the Material Balance Options section, select **Adsorption**. This corrects the data to include adsorbed gas, and shifts the data points up.

Note: When the Adsorption checkbox is selected, and after you have opened an FMB analysis, your Langmuir Volume (V_{LS}) and Pressure (P_{LS}) values are used. (You need to enter values for the Langmuir Volume (V_{LS}) and Pressure (P_{LS}) in the Properties editor (under **Formation / Rock, Adsorption**.)



Reposition the analysis line through the data points. The calculated OGIP now includes an adsorbed volume (OGIP_A).

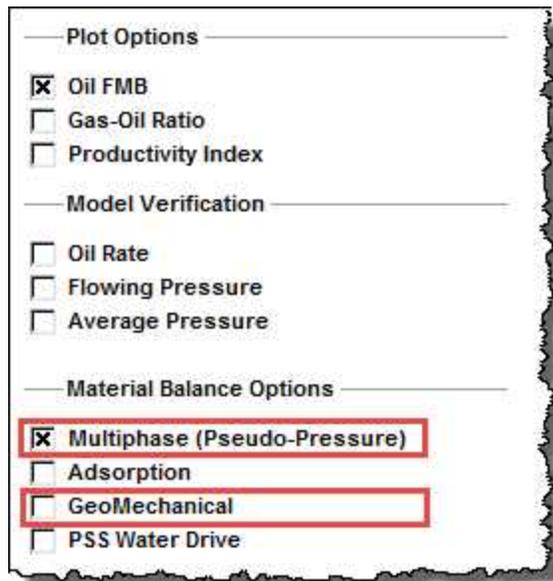


Accounting for changing oil properties

The classical flowing material balance (FMB) analysis is performed under the assumption that the variation of oil properties (compressibility, viscosity, formation volume factor) with pressure is negligible; therefore this variation is not taken into account.

To account for the variation of oil properties with pressure, select the **Multiphase (Pseudo-Pressure)** option. Calculations performed when this option is selected are based on using oil pseudo-pressure and are described in [accounting for variation in oil properties](#). Calculations use the oil properties that are set in the [Properties editor](#).

If you chose to account for the variation in oil properties, you can also account for variation in rock properties (permeability and formation compressibility) with pressure. To do this, select the **GeoMechanical** option. Note that for the Oil FMB analysis, this option is only available when the Multiphase (Pseudo-Pressure) option is selected. Calculations use the rock properties that are set in the Geomechanical section of the Properties editor.



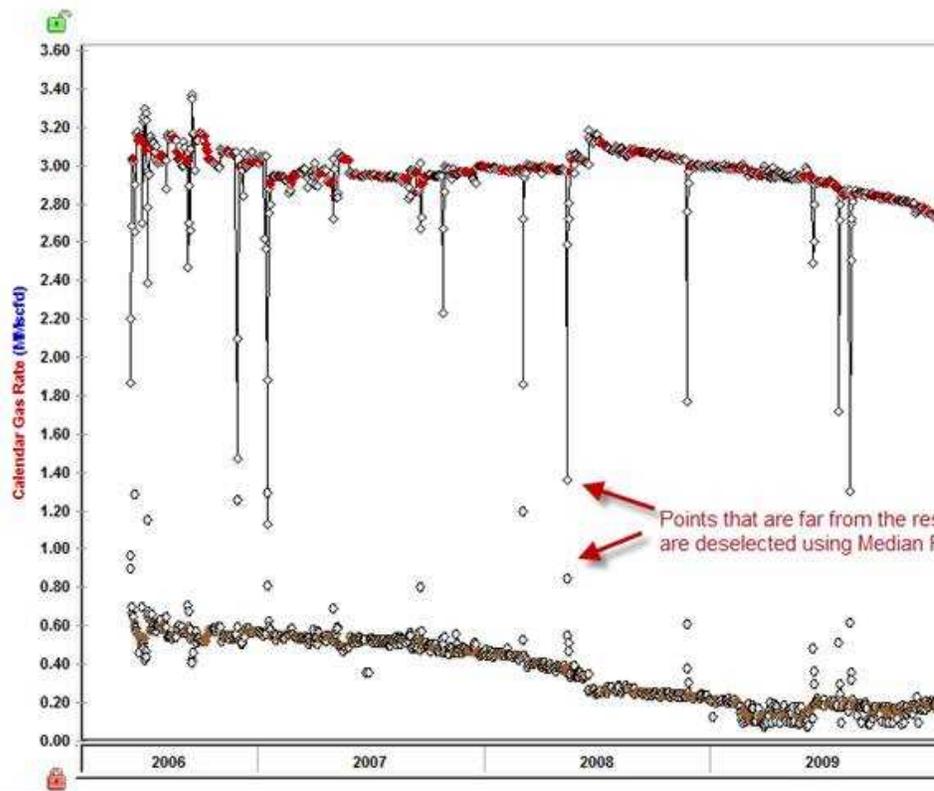
Data Filter dialog box

This dialog box is commonly used when you click the filter data for an FMB, typecurve, numerical URM, or unconventional reservoir analysis.

This dialog box has the following important icons:

- **Tools to Select Data Points for Filtering**  — opens an additional toolbar with point-selection options.
 - **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.
 - **select all data points** — selects all the data points on the plot.
 - **deselect all data points** — deselects all the data points on the plot.
 - **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.
- **Fully Automatic**  — select one of these options:

- **Median Filter** — used to make data less noisy by deselecting data points that are far from the rest of the data (those points are likely to be outliers). Note that the dataset needs to have at least 20 points for this filter to be applicable.



- **Liquid Load Filter** — in some cases, flowing pressures are not measured at sandface; instead they are measured at the wellhead, and Harmony Enterprise calculates sandface pressures (see [pressure loss calculations](#)) based on given wellhead pressures in the [wellbore editor](#). If the well is experiencing liquid loading, calculated sandface pressures may be inaccurate. Therefore, you may want to exclude corresponding data points from the analysis. With this filter, you can deselect data points where the well is experiencing liquid loading. For more information, see [liquid lift calculations](#).
- **Saturated Filter** — used to identify the portion of the data where flowing pressure is below the bubble point pressure (oil and gas flowing in the reservoir). For more information, see [saturated filter](#).

For information on common plot icons, see [plot toolbars](#).

Forecast consolidation

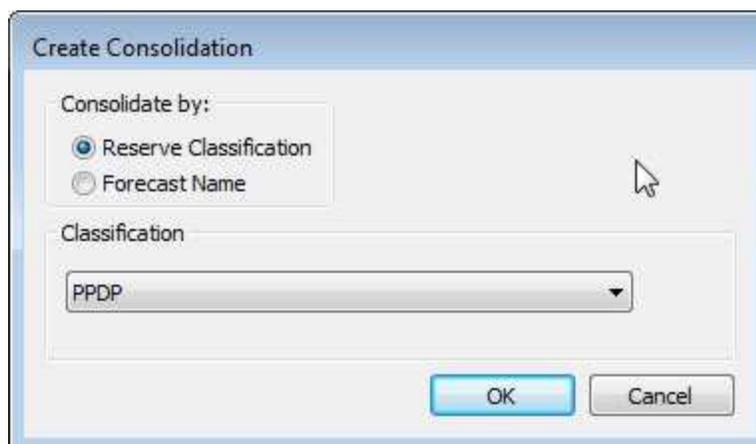
A consolidation is a summation of forecasts from constituent wells (historical data is aggregated). This analysis type can only be created at the group level, and is used to sum up forecasts within the group. Therefore, when creating a forecast consolidation for a set of wells, it must be created from a hierarchical group, or from a custom group (excluding reserve classification consolidations). Similarly, when creating a consolidation for a set of layers in a multilayer well, it must be created at the well level.

If you want to consolidate classified decline analyses, *and have the unclassified decline analyses produced fluid included*, you need to change a default setting in the Options dialog box. For more information, see classified consolidations.

Note: This forecast works with your Harmony Forecast™ license.

Be aware that classified consolidations have an additional field for the reference date.

When you add a forecast consolidation (see analyzing an entity), you can consolidate by reserve classification or forecast name.



The screenshot shows a dialog box titled "Create Consolidation". It has two main sections. The first section, "Consolidate by:", contains two radio buttons: "Reserve Classification" (which is selected) and "Forecast Name". The second section, "Classification", contains a drop-down menu with "PPDP" selected. At the bottom of the dialog are two buttons: "OK" and "Cancel".

- **Reserve Classification** — when selected, the Classification drop-down list is enabled. Note that classified consolidations only include classified forecasts with active reference dates.
- **Forecast Name** — when selected, the Name drop-down list is enabled.
- **Classification** — select your reserve classification from the drop-down list. There are two types of classified consolidations: proved (P) and total (T). There are nine P consolidations: PNP, PPNP, PPPNP, PDP, PPDP, PPPDP, PUD, PPUD, and PPPUD. The T consolidations are aggregates of the Ps, so TP = PNP + PDP

+ PUD. TPP = PPNP + PPDP + PPUD. TPPP = PPPNP + PPPDP + PPPUD. For more information on classifications, see [reserve classification](#).

- **Name** — select your analysis from the drop-down list. Note that named classifications are case sensitive. For example, Analysis 1 and ANALYSIS 1 cannot appear in the same consolidation.

Note: Consolidations can be done on ratio forecasts, water-oil ratio (WOR) / oil cut forecasts, and custom forecasts. If forecasts do not have the same forecast start date (FSD), the consolidation begins at the earliest FSD, and historical production is used for wells whose FSD starts later. Note that you cannot edit consolidation plots or results because they are directly governed by the forecasts of the constituent wells of the group.

Gas IPR / TPC

The Gas IPR / TPC analysis method creates tubing performance curves (TPCs) for a gas well, and overlays them on the sandface inflow performance relationship (IPR) curves. For reference material, see [Gas IPR / TPC theory](#) and [choke sizing](#).

Note: This analysis works with your Harmony Optimize™ license. For information on options, see [Optimize options](#).

For a given set of conditions, a TPC is a plot of the flowing sandface pressure, as a function of flow rate. This curve does not change through the life of the well. It is not at all dependent upon well performance; it depends only upon the gas-liquid ratio, tubular configuration (depth, diameter), wellhead pressures, etc.

On the Gas IPR / TPC plot, flow within safe operating conditions is denoted by a solid TPC line. Flow categorized as an operational risk is denoted by a dashed TPC line. Hover over the tooltip for additional context as to whether this is liquid loading and/or erosion.

The active IPR is highlighted with a blue border on the left-side of the main pane and the active TPC is highlighted on the right-side. In addition, the active TPC and IPR curves are displayed in bold when you hover over the plot. Click the inverted chevron icon () to open your IPR or TPC.

This analysis has the following icons in the Inflow and Outflow panes:

-  **Delete** — removes the currently selected inflow, outflow, gradient, or forecast.

-  **Copy** — creates a duplicate of the currently selected inflow, outflow, gradient, or forecast. The name is appended with the word "Copy".
-  /  **Show / Hide** — toggle between showing or hiding the inflow, outflow, gradient, or forecast.
-  /  **Collapse / Expand** — closes / opens the details for the inflow, outflow, gradient, or forecast. If you see a red triangle () in the top left of a collapsed analysis, you need to investigate the required parameters.

Inflow pane

The Inflow pane on the left-side has the following items:

- **Inflows** — click the **Add Inflow** button to create an inflow that is measured at the sandface.
 - **Simplified C, n** — the Simplified equation (C, n) is a widely accepted method for describing a well's deliverability (IPR) potential. Well test data (C, n, and reservoir pressure) can be entered directly, or an estimate can be made by entering reservoir pressure and a single test point.
 - **Forchheimer** — the Forchheimer equation can be used to estimate a well's IPR potential. Well test data (a, b, and reservoir pressure and temperature) can be entered directly, or an estimate can be made by entering several reservoir parameters (net pay, porosity, water saturation, and several others).
 - **Custom Table** — instead of an equation, the IPR can be described with two or more test points that are entered in tabular form. By default, all the test points are connected with straight lines (linear fit), but the points can also be fit to the Forchheimer equation.
- **Configuration** drop-down list — select the wellbore configuration or optimize configuration you want to use when converting from wellhead to sandface pressure. For more information, see [optimize configurations](#).

Note: For the inflow method, wellhead non-flowing pressure, the following flow paths are not supported: Both, Casing, Gas Lift, and Pumping.

For the inflow method, wellhead flowing pressure, the following flow paths are not supported: Gas Lift and Pumping.

Plot

The plot in the center of the window has the following items:

- **Plot** — the plot is displayed after you type all the required parameters. Intersections on the plot correspond to the points in the Operating Points table. The axes operate in the same manner as [Economics](#). For more information, see [Y-axis icons](#) and [X-axis icons](#). To rescale the plot back to its original settings, double-click it.
 - **Auto-scale to fit all** checkbox — fits the plot to the maximum viewable area of the screen.
 - **Show Sensitivities** checkbox — displays sensitized / transient inflows in the plot with a light-blue line, as well as inflows in the Operating Points table.
 - **Show all valve curves** checkbox — displays the outflow for every valve depth entered in the Optimize Configuration (only applies to the [artificial lift outflow](#)). If deselected, the deepest valve depth that calculates a valid operating point is used to display the outflow curve.
- **Operating Points** tab — this is the default plotting method that can show sandface IPR curves overlaid with TPCs. If at least one IPR and TPC are paired, then the intersection of the IPR and TPC is called the operating point. The operating points are then displayed in a table below the plot. Note that you can copy the table by right-clicking it and selecting Copy Table.
- **Inflow Comparisons** tab — this can be used to display both the sandface and wellhead IPR curve, if the wellhead IPR can be calculated.
- **SF to WH Comparison** tab — displays a plot for sandface-to-wellhead comparisons.

Outflow pane

(Operating Points tab only) The Outflow pane on the right-side has the following items:

- **Pair all with** checkbox — click this option, if you want to pair all TPCs with the inflow selected in the drop-down list to the right.
- **Parent inflow** drop-down list — select from the drop-down list.
- **Add Outflow** button — click to create a TPC. Type values or select from drop-down lists for fields in white. Gray fields are read-only. Note that all TPCs require a parent inflow and a wellbore.

- **Configuration** drop-down list — by default, the most-recent configuration is selected. If there is a red box around the Configuration drop-down list, you need to make corrections in the [Wellbore editor](#).
- **Add / Edit** link — opens the Wellbore Editor popup where you can create, delete, and edit Optimize Configurations without leaving the worksheet.
- **Wellhead FP** field — type your wellhead flowing pressure.
- **Liquid Ratios** section — select from the drop-down list, so you can type values for your ratios.
- **Gas Lift** inputs — only available when your selected configuration has its flow path set to **Gas Lift - Tubular** or **Gas Lift - Annular**.
 - **Reservoir Liquid Ratios** — converted from the Liquid Ratios section for Gas Lift Outflows. These inputs indicate the producing fluid ratios excluding gas lift injection volumes.

Injection Pressure — type your injection-side flowing pressure. This is in the opposite direction of the flow path.
 - **Injection Gas Rate** — type your intended gas lift injection rate.
 - **Injected Gas Gravity** — displays the specific gravity of the injected gas. To edit this value, navigate to **Editors, Properties, Gas Lift**.
- **Choke Calculator** section — for quick calculations of critical (sonic) flow conditions across a given choke diameter. You can run a wide variety of sensitivities on pressures, temperatures, and fluid properties.

For more information on multiphase-flow choke correlation limits, see [references](#).

Note: If you click the **SF to WH Comparison** tab, the Wellbore Reference pane is displayed instead of the Outflow pane.

Choke calculator

The choke calculator is a simple and effective tool for calculating sonic-flow characteristics of your well for both single-phase gas and multiphase fluids. The calculator can be used to determine the upstream or downstream pressure across your choke. It can also be used to find the temperature drop across the choke using the Joule-Thomson cooling correlation. The sonic gas rate is displayed at the bottom of the choke calculator.

Note: The choke calculator does *not* currently impact TPC calculations.

The choke calculator supports the following correlations:

- Rawlins-Schellhardt (single-phase gas)
- Ashford-Pierce (multiphase analytical)
- Achong, Baxendell, Gilbert, Ros (multiphase empirical)

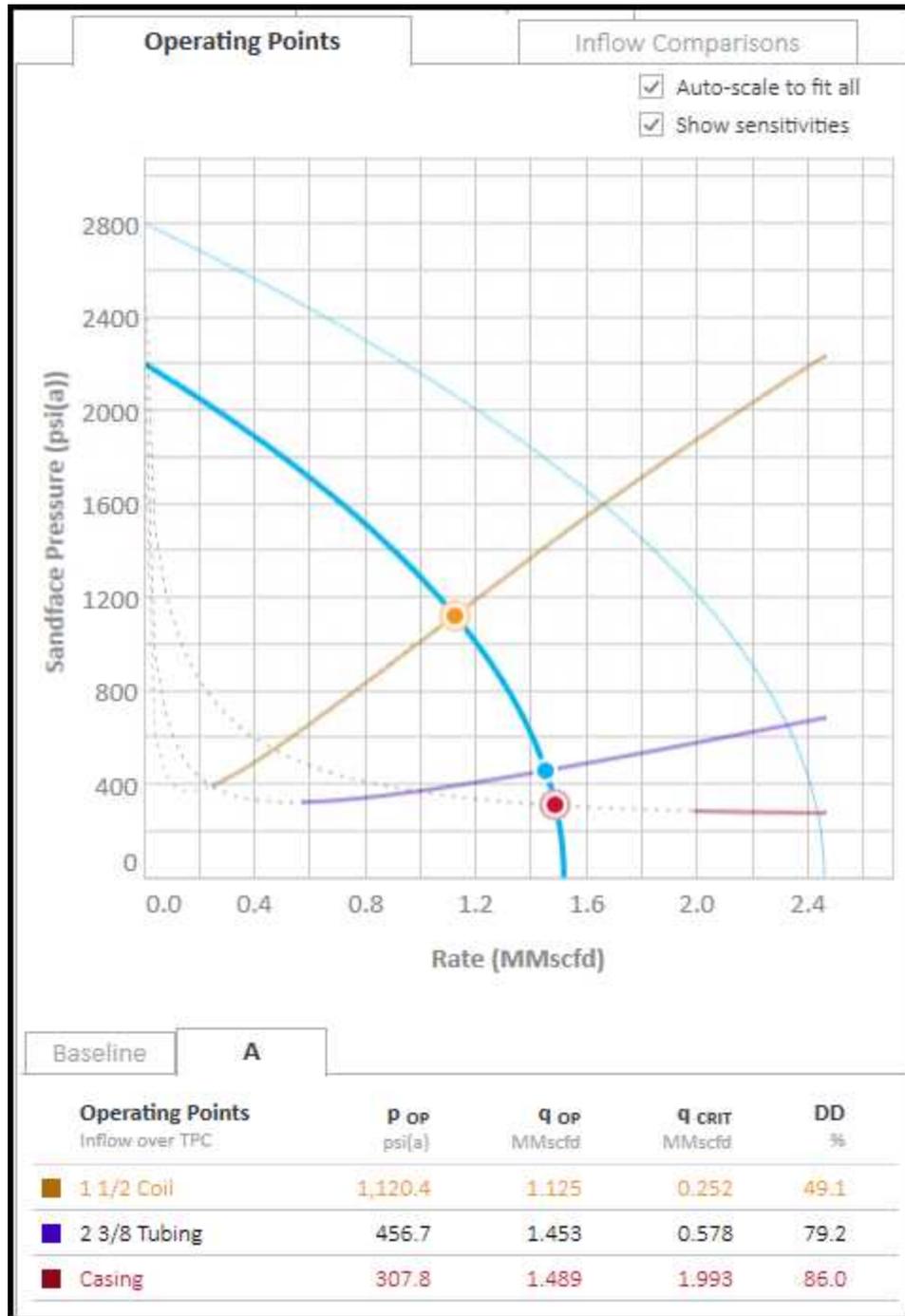
Diagnostics

The operating points are displayed in one of the following colors:

- **Dark blue** — the operating point is in the preferred range. In other words, the operating point is above the critical rate required to lift liquid, and below the erosional velocity.
- **Red** — the operating point is below the critical rate required to lift liquid.
- **Yellow** — the operating point is above the erosional velocity calculated for this configuration.

Note: You can set your default erosional velocity in the Options dialog box under the Optimize node. You can set liquid-loading options in the Wellbore editor. We recommend that you recreate TPCs in a flowing gradient worksheet for a full flowing assurance analysis.

In addition, the table below the plot displays text in a yellow font when erosion is predicted, and in a red font when liquid loading is predicted.



Operating Points table

The Operating Points table at the bottom of the window has the following key performance indicators (KPIs):

- **Baseline** tab — this shows the KPIs for the baseline (or primary) IPR.
- Additional tabs:
 - **A, B, and C** tabs — are displayed if you use the Future Inflows option in Simplified (C,n) IPRs.
 - **T1, T2, and T3** tabs — are displayed if you use a Forchheimer IPR and the transient inflows are calculated.

Tip: You can view your sensitivities if the **Show Sensitivities** checkbox is selected at the top of the window.

Note that you can view your H₂S rates for each of the operating points when the H₂S% in the Editors tab is greater than 0%.

Simplified C, n

The Simplified equation (C, n) is a widely accepted method for determining a well's deliverability (inflow performance relationship - IPR) potential. The calculation methods use the information provided to determine the well's IPR at the sandface. From here, further analysis may be performed, such as determining the well's wellhead deliverability potential, or comparing well performance scenarios by determining operating points along the deliverability curve(s) with the use of tubing performance curves.

Select a calculation method based on the information you have:

Calculation Method	Required Information	Description	Notes
Sandface IPR	<ul style="list-style-type: none"> ▪ Reservoir Pressure ▪ Sandface (SF) Turbulence Factor 	Harmony Enterprise calculates either a resulting Sandface IPR, or Sandface C value when either of the other entered.	You must type a value for one of the lower two fields. You can type three reservoir pressure sensitivities (A, B, and C).

Calculation Method	Required Information	Description	Notes
Sandface Flowing Pressure	<ul style="list-style-type: none"> ▪ Reservoir Pressure ▪ SF Turbulence Factor ▪ Gas Delivery Rate ▪ SF Flowing Pressure 	Harmony Enterprise calculates a resulting Sandface C and Sandface IPR.	You can type three reservoir pressure sensitivities (A, B, and C).
Wellhead Flowing Pressure	<ul style="list-style-type: none"> ▪ Physical Wellbore ▪ Reservoir Pressure ▪ SF Turbulence Factor ▪ Gas Delivery Rate ▪ Wellhead Flowing Pressure 	Harmony Enterprise uses the wellbore and Liquid Ratio information to calculate the SF Flowing Pressure used to determine the Sandface IPR value. The most-recent wellbore configuration is used by default. If there is no wellbore, the <u>Wellbore editor</u> must be used to enter one.	You can type three reservoir pressure sensitivities (A, B, and C)
Wellhead Non-Flowing Pressure	<ul style="list-style-type: none"> ▪ Physical Wellbore ▪ Reservoir Pressure ▪ SF Turbulence Factor ▪ Gas Delivery Rate ▪ Wellhead Non-Flowing Pressure 	Harmony Enterprise uses the wellbore and Liquid Ratio information to calculate the SF Flowing Pressure used to determine the Sandface IPR value. The Average Liquid Gradient is applied to the height of the liquid column from the Liquid Level (LL) to the	You can type three reservoir pressure sensitivities (A, B, and C).

Calculation Method	Required Information	Description	Notes
		Datum depth.	

If you type values in a parameter field that is beyond the acceptable range, a red box highlights the field, and a tooltip advises you about what is incorrect.

Forchheimer inflow

By using the Forchheimer inflow, you can estimate a well's inflow performance relationship (IPR) potential by entering its reservoir parameters after selecting the pseudo-pressure method or pressure-squared method. You can also calculate when a reservoir reaches boundary-dominated flow.

Calculate a Gas Deliverability curve by entering:

- Reservoir Parameters
- Sandface a and b values

When you enter all necessary parameters, Harmony Enterprise calculates and displays the results and transient inflows.

Note: The View Transient IPR Curves option is only available if reservoir parameters have been entered.

Optionally, you can:

- Add Horizontal Permeability
- Add Partial Penetration

Note: The Transient inflows section is blank until all the required parameters are entered.

Custom table inflow (gas)

With the gas custom table, you can import inflows (deliverability curves) into Harmony Enterprise that have been generated elsewhere.

Type your reservoir pressure and temperature, then select your fit type:

- **Forchheimer** — is a commonly used inflow performance relationship (IPR) correlation for gas wells. It requires a minimum of two input points in the custom table to create an inflow curve.
- **Linear** — is a straight-line interpolation between test points. However, it does not extrapolate to beyond the highest rate entered. It requires a minimum of one input point in the custom table to create an inflow curve.

Note: The Custom Table uses pseudo-pressure for all Forchheimer calculations.

The Custom Table uses your input test points consisting of a stabilized production rate and a sandface flowing pressure, and it uses all valid input points selected in the Plot column. If the Plot checkbox is deselected for an input point, that point is omitted from inflow calculations, and is not displayed on the plot.

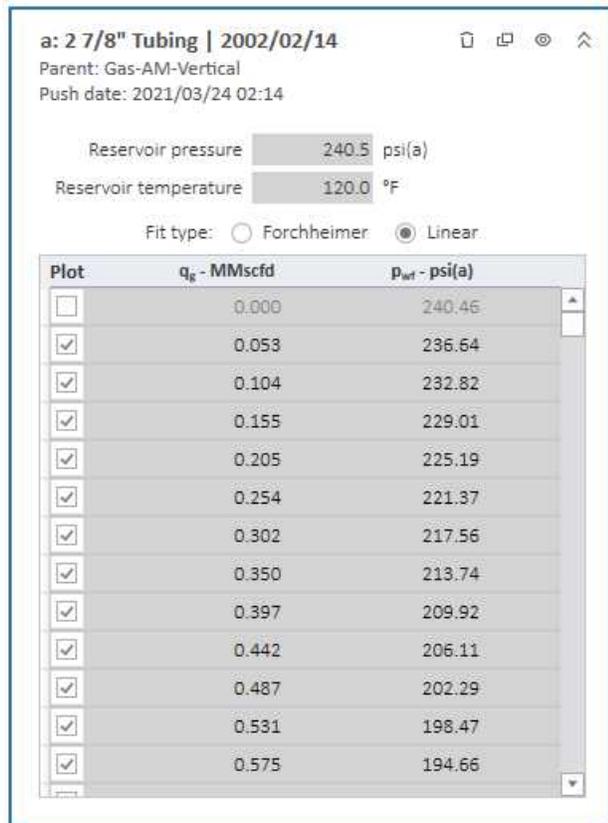
If you have an error in the Custom Table, an error indicator is displayed along with a tooltip. Examples of error messages are as follows:

- **q <= 0** — the production rate must be greater than zero.
- **>p_R** — the sandface pressure must be less than the reservoir pressure.
- **<p_{atm}** — the sandface pressure must be greater than average atmospheric pressure (14.7 psia or 101.3 kPaa).
- **Dupl.** — if two data points exist that use the same oil rate, then the Custom Table only uses the point with the higher sandface pressure for inflow calculations, so long as this higher point does not trigger any other error messages.

Imported IPRs (from Advanced Forecast)

From Advanced Forecast, you can push an IPR to an IPR / TPC worksheet.

After a curve is pushed from the Advanced Forecast worksheet, it becomes a read-only analysis in the IPR / TPC worksheet. There is no synchronization between the imported forecast and the source Advanced Forecast analysis.



The analysis name is set to "<Forecast Name> | <Forecast Date>", and is read-only. Below the analysis name are two sub-headers: the first is the name of the parent analytical model; the second is the push date. This date is the date and time at which the inflow curve was sent from the Advanced Forecast worksheet. This is a means of version control in case changes have been made to the Advanced Forecast or the parent analytical model.

The custom table is populated with a read-only array of rates and flowing pressures corresponding to the IPR from the Advanced Forecast. All data points are pulled across, with any invalid points being deselected.

Note: If you want to edit the IPR, click the **Copy** icon () to create an editable copy.

Imported TPCs (from Advanced Forecast)

A pushed TPC is similar to that of a pushed IPR. The analysis name is set to "<Forecast Name> | <Forecast Date> | Outflow". This read-only pane includes additional information regarding the parent analytical model and push date.

The Parent Inflow selection remains editable so you can pair your pushed Outflow to any Inflow analysis panes on the same worksheet.

The wellbore configuration selection, flowing pressure, and wellbore dimensions are read-only and reflective of the wellbore conditions at the specified forecast step.

If secondary fluid ratios are specified in the Advanced Forecast, these are reflected in the Liquid Ratios section at the bottom of the Outflow pane.

The screenshot shows a configuration window for an outflow analysis. At the top, it displays the title 'a: 2 7/8" Tubing | 2002/02/14 | Outfl...' and provides context: 'Paired to a: 2 7/8" Tubing | 2002/02/14', 'Parent: Gas-AM-Vertical', and 'Push date: 2021/03/24 02:14'. Below this, there are three main sections: 1. Parent Inflow and Configuration: 'Parent inflow' is set to 'a: 2 7/8" Tubing | 2002/02/14' and 'Configuration' is '2 7/8" Tubing'. 'Wellhead FP' is 143.51 psi(a). 2. Casing Dimensions: 'Inner diameter' is 5.000 in and 'Roughness' is 0.000600 in. 3. Customize Flow Path and Tubing: The 'Tubing' radio button is selected. 'Bottom depth (MD)' is 4,999.0 ft. 'Outer diameter' is 2.875 in, 'Inner diameter' is 2.441 in, and 'Roughness' is 0.000600 in. At the bottom, 'Liquid Ratios' are shown: 'Gas:Oil' is scf/bbl and 'Water:Gas' is bbl/MMscf.

Note: If you want to edit the TPC, click the **Copy** icon (📄) to create an editable copy.

Artificial lift outflow

With your Harmony Optimize license, you can have outflow analyses with an artificial lift flow path. First, you need to create an Optimize Configuration in the [Wellbore editor](#). After creating the Optimize Configuration, set the flow path to **Gas Lift - Tubular** or **Gas Lift - Annular**.

Note: The **Pumping** flow path cannot be used with [Gas IPR / TPC analyses](#).

Gas lift

After selecting a gas lift configuration, the Outflow pane on the right-side adds a **Gas Lift Injection** section, which requires the following additional inputs:

- Injection Pressure
- Injection Gas Rate
- Injected Gas Gravity (this value defaults to the value entered in the [Properties editor](#))

For information on valve depths, see [show all valve curves](#).

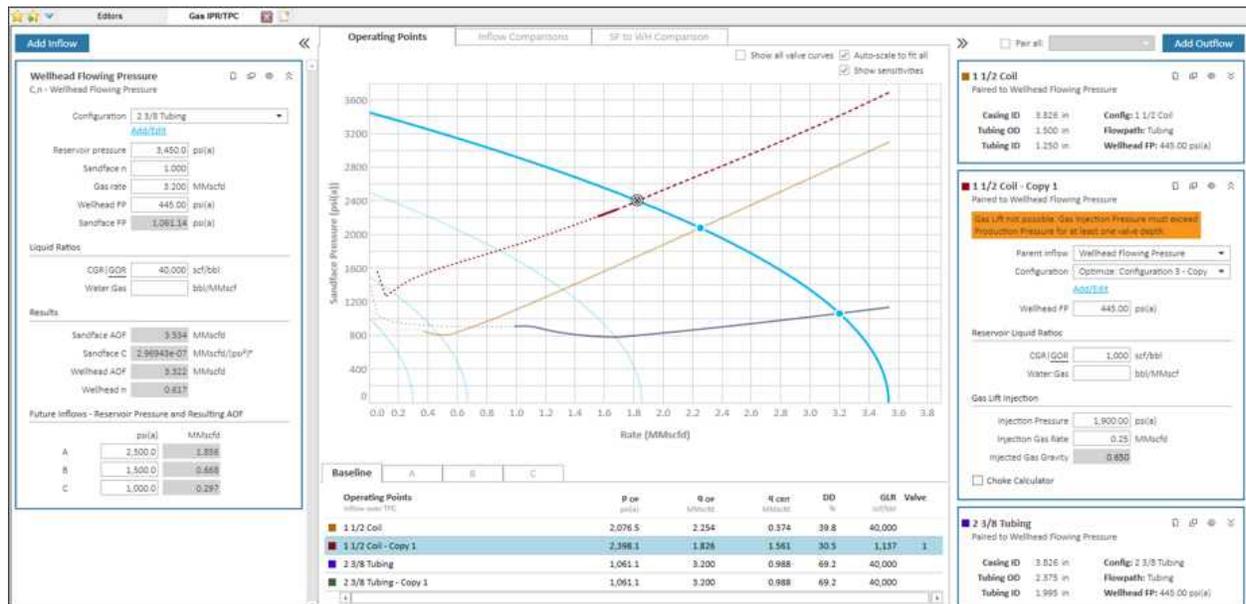
Plot and operating points

The operating points on the plot are displayed in one of the following colors:

- **Dark blue** — the operating point is in the preferred range.
- **Red** — the operating point is below the critical rate required to lift liquid.
- **Yellow** — the operating point is above the erosional velocity calculated for this configuration.
- **Black "X"** — the operating point is invalid (gas lift is not possible).

Example

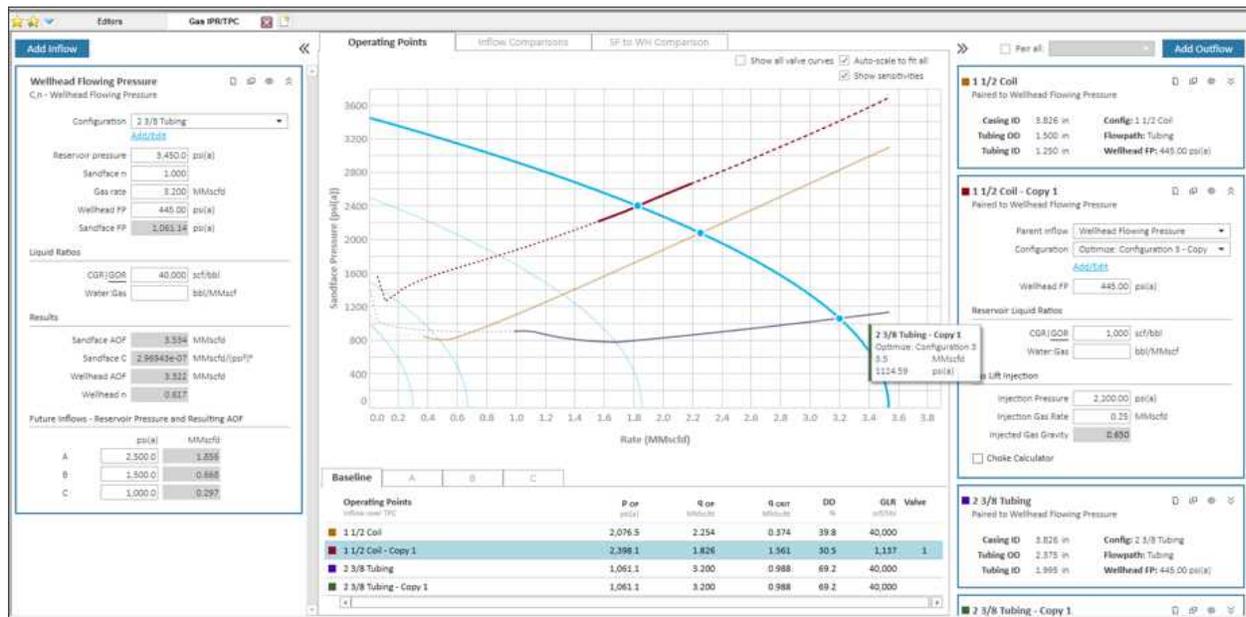
In this screenshot, gas lift is not possible. This is denoted by orange highlighted text in the Outflow pane and an X icon for the operating point on the plot. Furthermore, the performance curve is displayed with a long dashed-line segment, which indicates that the producing rate is too high for gas lift to be possible.



To fix the problem, you may need to:

- change the injection pressure.
- change the injection rate.
- change the wellbore settings in the Optimize Configuration, such as the valve depth.

In this screenshot, the gas lift outflow curve is operating in the preferred range. The warning message is gone and the operating point icon is in its normal blue state.



Material Balance analysis

The material balance analysis is an interpretation method used to determine original fluids-in-place (OFIP) based on production and static pressure data. For more information, see [material balance theory](#).

Note: This analysis works with your Harmony Forecast™ license.

Harmony Enterprise supports:

- [gas material balance \(GMB\)](#)
- [oil material balance \(OMB\)](#)

Gas material balance

With the gas material balance (GMB) analysis, you can select: **Pressure-Function vs. Cumulative Gas** or **Pressure vs. Time** for a single well, or a group of wells.

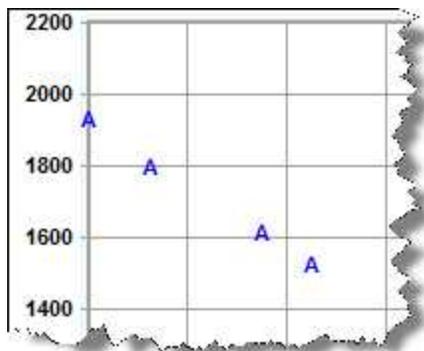
The analysis line for GMB determines the original gas-in-place (OGIP). The expected ultimate recovery (EUR) can be determined using a recovery factor (RF) or abandonment pressure (P_{ab}).

Note that the default calculation for EUR is the Auto option. For more information, see the Analysis Parameters pane below.

Tip: On a p/Z plot, the analysis trend is linear, and the line can be manipulated manually, or by changing the point selection for the best fit. On a Pressure vs. Time plot, the analysis is not a linear trend, and the only way to manipulate the analysis is through point selection.

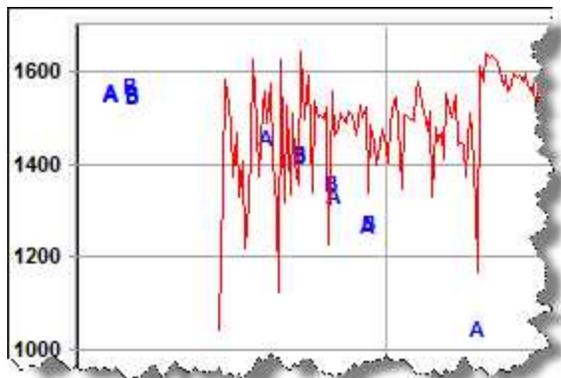
Single well analysis

The well's static pressures are displayed as a letter. For a single-well analysis, the same letter is used for all pressures.

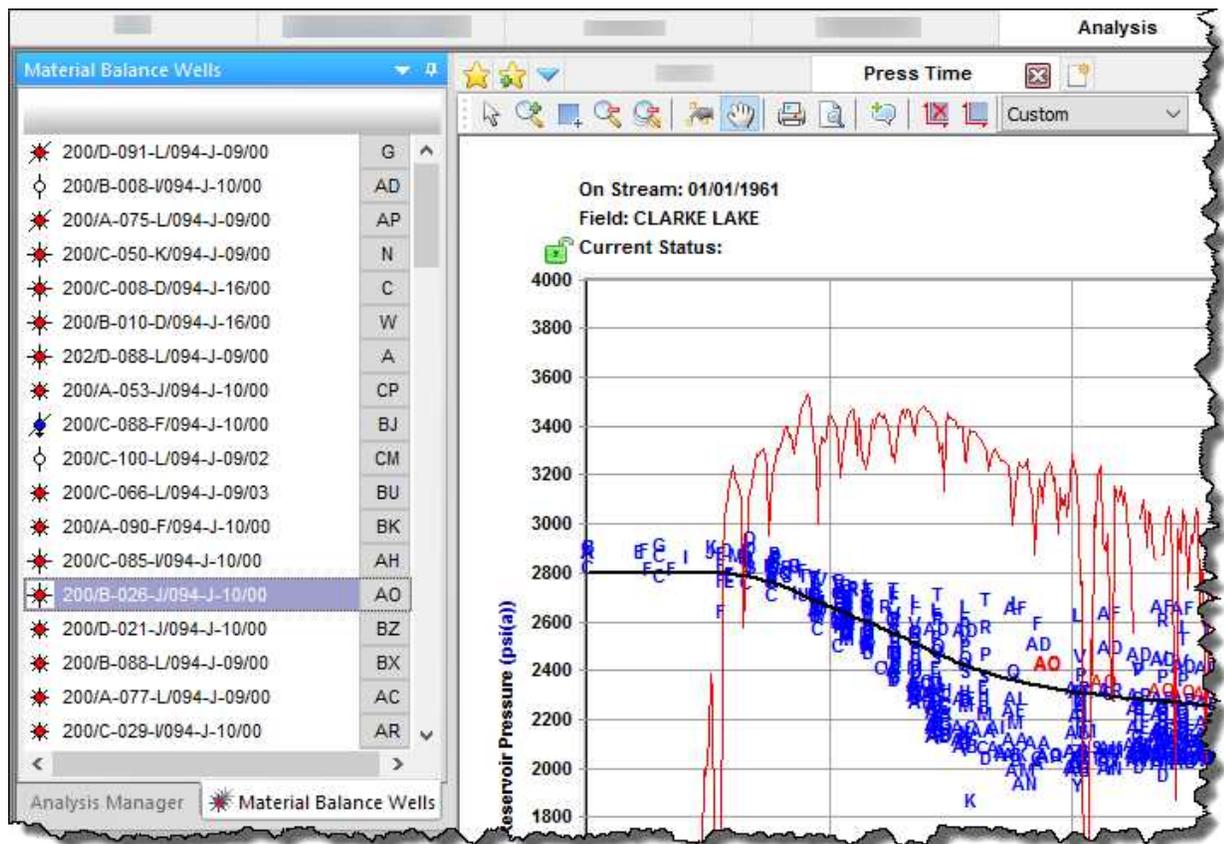


Group well analysis

When a group is analyzed, each well is represented by a different letter.



In addition, there is a Material Balance Wells tab / pane where you can select various wells.



As you hover over various wells in the main pane, their analysis line and well letter is displayed in bold.

Context menus

Right-clicking a well in the Material Balance Wells pane lists these options:

- **Duplicate Selected into Shared Custom Group** — copies the selected entities into the shared custom group you select from the submenu.
- **Duplicate Selected into Private Custom Group** — copies the selected entities into the private custom group you select from the submenu.
- **Move Selected into Shared Custom Group** — moves the selected entities into the shared custom group you select from the submenu.
- **Move Selected into Private Custom Group** — moves the selected entities into the private custom group you select from the submenu.

For more information, see [shared](#) and [private custom groups](#).

Analysis Parameters pane

This pane has the following items that you can adjust:

- **Lock p_i** — select Yes or No.
- **p_i** — type your initial reservoir pressure.
- **Abd Calc** — select from the drop-down list:
 - **Auto** — estimates the depth by dividing the initial pressure by the water gradient (0.433 psi/ft). The abandonment pressure is then 35 psi plus 35 psi for every 1,000 ft of depth.
 - **Specify P_{ab}** — you can specify a final reservoir pressure that is used to calculate the corresponding production at this pressure and the recovery factor for gas (RF_g).
 - **Specify RF** — you can specify a percentage of the original gas in-place (OGIP) from the analysis, and the corresponding abandonment pressure is calculated.
 - **None** — RF and P_{ab} are left blank; therefore, expected ultimate recovery (EUR) and remaining recoverable (RR) are not calculated.

Toolbar

The Analysis Parameters toolbar has the following icons:

-  **Show / Hide Abandonment Line** — toggle this line on or off. This line represents the abandonment pressure in terms of p/Z or p/Z^{**} , and the expected ultimate recoverable reserves.
-  **View data for the current analysis and adjust data point selection** — opens the Material Balance Data Point Selection dialog box where you can view, print, preview, and export your data to a .csv file.
-  **Open advanced options for this analysis** (if applicable) — applies to advanced GMB analyses, but in some cases, these options can be applied to non-advanced GMB analyses. Opens the Advanced Material Balance Options dialog box where you can adjust four areas of your GMB: producing reservoir, geopressured, water drive, and connected reservoir.
-  **Show GMB diagnostics grid** — opens the Material Balance Data dialog box where you can view, print, preview, and export your calculated and synthetic data to a .csv file.

GMB plots and parameters

Gas material balance (GMB) analyses can use a pressure function vs. cumulative gas, or pressure vs. time.

The pressure function depends on the type of analysis:

- GMB uses p/Z
- Advanced GMB uses p/Z^{**} (including aquifer effects, but excluding desorption effects)

In order for data to be displayed on the worksheet, the well or group being analyzed must have at least one static pressure value in the Static Pressure editor. Gas gravity, or gas composition and reservoir temperature must be provided in the Properties editor.

Data points in the plot can be turned on or off by selecting / deselecting checkboxes in the **Use in Analysis** column of the Static Pressure editor.

The screenshot shows the 'Static Pressure' editor in the Harmony Enterprise software. The left sidebar contains a list of editors: Test Info, Shut-in Time, Static Wellhead Pressure, Effective Gradient, RD - Datum Offset, Run Depth Pressure Gradient, Run Depth Temp, and Comments. The main window displays a table of test data with the following columns: Test Date, Static Run Depth Pressure, Run Depth (TVD), and Use in Analysis. The 'Use in Analysis' column has checkboxes for the first two rows, which are checked.

	Test Date	Static Run Depth Pressure	Run Depth (TVD)	Use in Analysis
	MM/DD/YYYY	psi(a)	ft(KB)	
1	01/03/2002	568.26		<input checked="" type="checkbox"/>
2	01/04/2002	568.26	3949.80	<input checked="" type="checkbox"/>
3				<input type="checkbox"/>

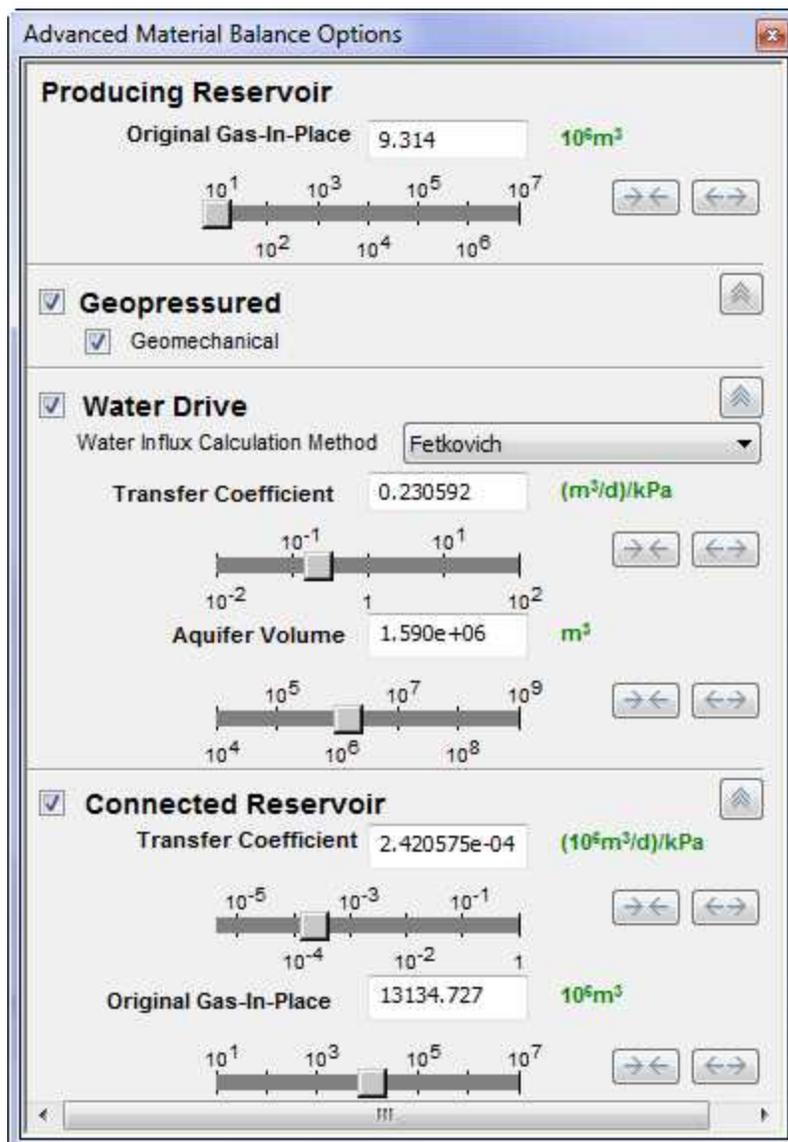
Advanced GMB

You can add an advanced gas material balance (GMB) analysis to an existing GMB worksheet by clicking the **Open advanced options** () icon in the Analysis Parameter pane's toolbar.

Or, you can add an advanced GMB analysis to a new worksheet by clicking the **Add an analysis** () icon in the Analysis Manager's toolbar and selecting **Gas - Advanced Material Balance**.

Note: Advanced material balance options are not compatible with all PVT correlations. For example, the Ovalle correlation is not compatible with advanced material balance.

In both cases, the Advanced Material Balance Options dialog box opens.



Select the options you want to use:

- **Geopressed** — this model does not have parameters in the GMB worksheet. In the Properties editor in the Geomechanical node, a correlation for formation compressibility can be set. This is what is used with the geopressed model to account for formation compressibility in the analysis. The additional reservoir properties that are required for the correlation are initial pressure and porosity.
- **Water Drive** — these models have parameters in the Advanced Material Balance Options dialog box to match the analysis.

- **Connected Reservoir** — these models have parameters in the Advanced Material Balance Options dialog box to match the analysis.

For the water drive and connection reservoir models, the Pressure vs. Time worksheet is often easier to use for matching the analysis. First, match the initial decline trend using the standard GMB analysis, then add the water drive or connected reservoir advanced model. Start the parameters with a low connected aquifer / gas reservoir, then increase the transfer coefficient to a region where the pressure data is very sensitive to a changing transfer coefficient. The transfer coefficient is used to match the initial pressure support trend, and the connected volume is used to match later pressure data. You may need to manipulate one parameter and then the other, back and forth, until you are satisfied with the match. Because two parameters are used in a single equation for the match, the solution is not unique. It is better to stick with a smaller connected volume, unless other indications of a large connected volume (geology, etc.) are present.

Oil material balance

With the oil material balance (OMB), you can analyze static pressure data for oil wells or groups to interpret the original oil in-place. With this analysis, you can account for pressure changes due to water encroachment, changes in formation compressibility, and volatile oil.

OMB equations are very sensitive to data quality. When performing an OMB analysis, it is important to remember that a lot of the parameters cannot be measured, so they are based on estimates.

Analysis Parameters pane

This pane has the following items that you can adjust:

- **Geomechanical** — click this checkbox to enable this option. Note that you must enter Geomechanical values in the [Properties editor](#).
- **Water Drive** — click this checkbox to enable this option.
- **Volatile Oil** — click this checkbox to enable this option. Note that you must have liquid-rich gas values in the Properties editor.
- **OOIP** — original oil in-place is both the main analysis result and one of the parameters that can be adjusted.
- **m** — type your gas cap oil leg ratio.
- **OGIP_F** — (required) type your original gas in-place.

Note: Both m and $OGIP_F$ represent free gas in-place, and you can best-fit on $OGIP_F$, type a value for $OGIP_F$, or type a value for m .

- RF_o — type your oil recovery factor.

When you click various checkboxes in the Parameters and Results section (for example, OOIP, $OGIP_F$), this influences which parameters are adjusted when using point selection to best-fit pressure data.

Toolbar

The Analysis Parameters toolbar has the following unique icons:

-  **Injection Gas Properties** — opens a dialog box where you type a custom Formation Volume Factor table for injected gas.
-  **Results Grid** — opens the Oil Material Balance Results Grid dialog box where you can view OMB results in a tabular format.

Plot dashboard

The Generalized Havlena-Odeh Analysis plot is displayed in the top left corner of your dashboard. By default, the other three plots that are displayed are Havlena-Odeh, N vs Time, and Pressure History Match.

Important: You can switch which plot is displayed by clicking the **Change Plot** button in all of the plot toolbars (that is, Campbell, Dake, Drive Indices, Havlena-Odeh, N vs Time, Pressure History Match, and Pressure vs. N_p). For more information, see [OMB theory](#).

Multi-segment decline analysis

You can add a multi-segment decline analysis to a decline worksheet (see [analyzing an entity](#)).

Note: This analysis works with your Harmony Forecast™ license.

When you add a multi-segment decline analysis to your worksheet, Harmony Enterprise initializes your analysis with a two-segment decline analysis, based on the initialization settings specified in the [Options dialog box](#). You can add as many decline segments as you want to the first two segments, by clicking the **Add Segment** icon on the Analysis Parameters toolbar.

Note: Segments can only be added or removed after the first two (fixed) segments, and these segments follow the [Arps' decline analysis](#).

Multi-segment decline analyses have these properties:

- The *first segment's* decline starts at either the *initial production date*, or the date corresponding to the historical *peak rate*, based on your multi-segment decline options.
- The *nominal decline rate* (a) at the end of the *first segment* is equivalent to the *nominal decline rate* at the beginning of the *second segment*, in order to enforce a smooth transition between these two segments.
- The q_i (initial production rate) of the *second segment* is set to the q_f (final production rate) of the *first segment*.
- After you add a *secondary segment* (to these two initial segments), q_i of the *secondary segment* is set to the q_f of the preceding segment. Also, the *nominal decline rate* (a) at the beginning of the new segment and end of the preceding segment are set to be equal. For information on how a new segment is initialized, see [decline initialization](#).
 - For a new segment, you can specify your [calc method](#), but the default method is q_f / Q_f . This method enables you to enter the initial rate (q_i), initial effective decline rate (d_i), b value, and time; the calc method calculates the final rate (q_f), and cumulative production (Q_f).
 - The b value defaults to the value from the preceding segment, and a duration of *60 months* is initially applied.

Analysis Parameters pane

For a description of general parameters and options, see the [decline: Analysis Parameters pane](#) and [decline: Analysis Parameters toolbar](#).

The differences between multi-segment and Arps' decline analyses are described below.

The screenshot shows the 'Analysis Parameters' dialog box with the following sections and fields:

- Forecast Start Date:** Op. Day, Forecast Start Date (01/01/2004), Q (363.6), d (6.961), b (1.000), d_{lim} (0.918).
- Segment 1:** Start Date (11/17/1997), Q (1514.6), d (12.000), d_{lim} (12.129), b Method (Input), b (1.000), Q_e (1564.5), End Date (11/17/1998), Q_i (726.711).
- Constraints:** d_{lim} Method (Input), d_{lim} (12.000), d_{lim} (Input), d_{lim} exp (Input), d_{lim} hyp (Input).
- Segment 2:** Start Date (11/17/1998), Q (1594.5), d (8000.000), d_{lim} (18.817), b Method (Input), b (1.000), d_{lim} exp (Input), Q_e (25.9), End Date (11/20/2008), Q_i (2658.904).

- For the initial (segment #1 and segment #2) decline segments, a calc method cannot be specified.
- You can choose for your b value to be manually *input*, or selected from a custom attribute, under the **b Method** drop-down list.
- You can modify the constraints for your first decline segment under segment 1. For additional information, see constraints.
- For the second segment, you cannot specify a calc method, but you can define a limiting decline rate (both exponential and hyperbolic) by toggling **d_{lim} exp** / **d_{lim} hyp** and entering a value.

Line manipulation

Most of the line manipulation from the decline analysis is the same. However, some of the functionality is slightly different for the initial and secondary segments of your decline.

1. Since the initial decline rate at the beginning of the second segment is forced to be equivalent to the decline rate at the end of the first segment, you cannot use the *Ctrl* key to change the curvature, and hence the *b* value of the second segment. However, you can still use this functionality on any other secondary segment.
2. For the purpose of maintaining a smooth transition between the two segments, you cannot "click, grab-and-drag" the second segment and tilt your decline.

Line manipulations are initiated by clicking (sometimes while pressing the **Ctrl** or **Shift** keys) the line itself, or one of the manipulation points for a given segment (start date, forecast start date, or end date). You can cancel your line manipulation by pressing the **Esc** key.

Tip: Any time you see "click", this means to left-click your mouse. Right-click actions are specifically mentioned.

- **Forecast Start Date, (FSD)** (indicated by a green triangle on the decline line)
 - **Click, grab-and-drag** — moves the FSD along the decline curve, but does not change the decline itself. The *FSD* and consequently the production rate (q), and the effective decline rate (d_{sec}) are updated.
 - If you position the *FSD* anywhere beyond the historical production data on a rate-time plot, it simulates a shut-in. Note that you cannot locate the *FSD* beyond the historical production data on a rate-cumulative plot.
 - If you move the *FSD* to the first segment and then grab-and-drag, the decline line shifts vertically when you move your mouse up and down. The shape of the decline (b and d) is preserved, and q and q_i get updated.
 - **Shift key** — the effect of the Shift key on FSD depends on where the FSD is located:
 - If the *FSD* is located in the *second segment* (the default position), pressing the **Shift** key results in behavior similar to "click, grab-and-drag".
 - If you move the *FSD* to the *first segment* of the decline, pressing the **Shift** key enables you to move the FSD along the decline curve.
 - **Ctrl key** — if the *FSD* is located in the *second segment*, pressing the **Ctrl** key results in behavior similar to "click, grab-and-drag". However, if FSD is on the *first segment*, pressing the **Ctrl** key enables you to translate the decline in time.
- **Start Date** (indicated by a blue circle)
 - For any segment excluding the second segment, all three line functions (1. click, grab-and drag, 2. Shift key, 3. Ctrl key) behave the same as the default "click, grab-and-drag" behavior for the Start Date.
 - For the *Start Date* of the *second segment*, all three line functions behave the same and enable you to reposition the point along the decline curve. The Start Date adjusts the transition point by setting the time constraint to the current position and clearing the other constraints.
- **End Date** (indicated by a blue square)

- For the *first segment* and *second segment*, all three line functions behave the same. They extend your forecast forward in time and decrease your abandonment rate (q_f). The final cumulative production (Q_f) increases, but none of the decline parameters change.
- For any additional segments, line functions performed on the end date behave the same as the default end-date line functions.
- **Any point on the forecast decline curve** (activated when the decline segment turns orange)
 - All line functions remain the same as the default "any point" line functions, when you adjust the *first segment* or any *added segments*.
 - You cannot manipulate the *second segment*.

Note: To customize your decline line, see decline-line customization.

Multi-well model

There are two types of multi-well model:

- Conventional — use to model wells with Vertical, Horizontal, or Fracture completions.
- Unconventional — use to model Horizontal Multifrac wells.

Conventional multi-well model

With the conventional multi-well (CMW) model, you can simulate multiple wells using the *group* numerical model to history-match producing wells and forecast future production. For theoretical information, see modifications for multi-well models.

Note: This model works with your Harmony Reservoir™ license.

Before you start using the multi-well model, make sure that all required information is added to the Harmony Enterprise project:

- Populate sandface locations for each well in the Attributes tab.
- Populate well production data (rates and sandface pressures) in the Production editor for each well in the group.

- Specify reservoir and fluid properties in the [Properties editor](#) of the group. When you create a new multi-well model, group reservoir properties are automatically applied.
- Populating wellbore information (such as, a deviation survey, completion, and perforation data) is not required. However, we recommend populating this information because it helps to initiate the multi-well model with correct default settings.

We recommend that you perform analyses and/or modeling for individual wells prior to using the multi-well model. You can bring in parameters from individual well analyses as a starting point for the multi-well model. Additionally, you can perform certain group analyses. For example, a flowing material balance (FMB) performed on the group gives an estimate for original fluid in-place for the reservoir.

By default, the [Plots tab](#) opens (with the Wells button selected) with a dashboard with four plots. For more information, see [dashboard](#).

Model creation

To create a CMW model:

1. Create a group (in the [Entity Viewer - Hierarchy](#) or [Entity Viewer - Custom](#)) that contains all the wells you want to include in the model.
2. Launch the group for analysis. For more information, see [selecting an entity for analysis](#).
3. Click the **Group** image and select **Multiphase Multi-well Model, Conventional**.

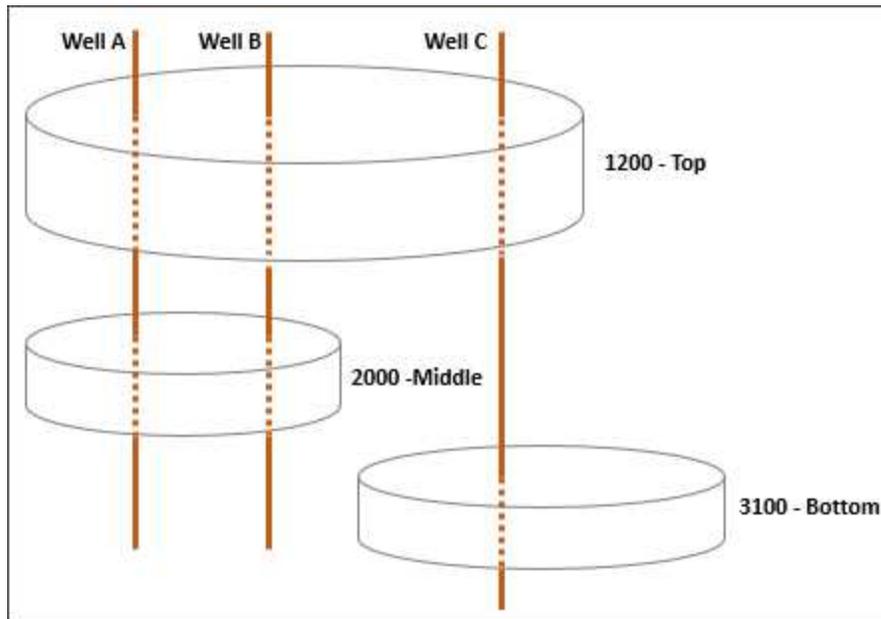
You can create a Black Oil, Volatile Oil, or a Gas Condensate model:

- **Black Oil** — accounts for gas dissolved in liquid, but does not account for liquid vaporized in gas; therefore, you should not create a Black Oil model for a group that has liquid-rich gas as a gas type.
- **Gas Condensate** — used to create a multiphase model that accounts for liquid vaporized in gas. This model should only be used for groups that have liquid-rich gas as their gas type.
- **Volatile Oil** — used to create a multiphase model that accounts for liquid vaporized in gas. The water phase can be turned off within the model..

Note: For more information, see [modifications for the multiphase model](#).

Multilayer CMW model

You can model production from multiple layers using the CMW model.



When modeling a layered reservoir using the CMW model:

- Layers are communicating with each other only through wellbores.
- Pressure drop between layers across the wellbore is calculated using a simplified wellbore model. When using this model, pressure drop between the layers is close to the hydrostatic pressure drop across the wellbore (while the friction pressure drop is ignored).
- Each layer is considered to be flat. (There is one datum depth per layer, but the net pay may vary from well-to-well.)
- All layers share the same set of PVT properties and relative permeability curves, which are defined in the Properties editor for the group.
- Each layer can have its own initial pressure.

- Geological properties (that is, net pay, porosity, permeability, and saturations) are set up per layer, per well.
- Layer boundaries are set up for each layer individually. As a result, some wells may be outside the boundary of some layers.
- If the well is modeled to operate under Use Rate control mode, the commingled rate of the well is used. The model outputs simulated rates for the well and for individual layers. Historical layer rates (if available) are displayed on the Well Rate time plot, but are *not* used in model calculation.
- Historical pressure for each well is taken from the Production editor of the top layer perforated by that well, if the well has a layer entity with the same name. Otherwise (for example, if the well does not have layer entities), historical pressure is taken from the Production editor of the well.
- If the well is modeled to operate under Use Pressure control mode, historical sandface pressure is interpreted as flowing pressure at the very top layer perforated by the well. The model outputs simulated sandface flowing pressures for the well and for individual layers. Historical calculated sandface pressures for layers (if available) are displayed on the Well Rate time plot, but are not used in model calculation.

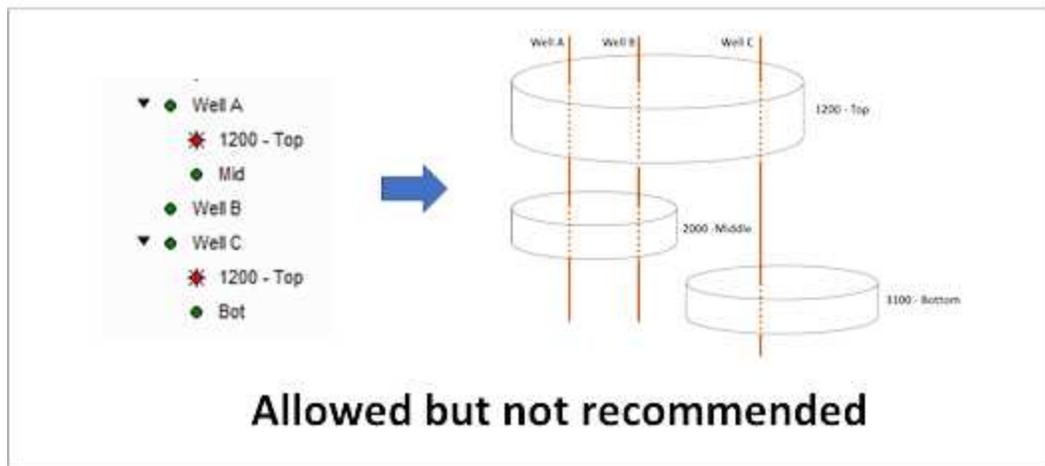
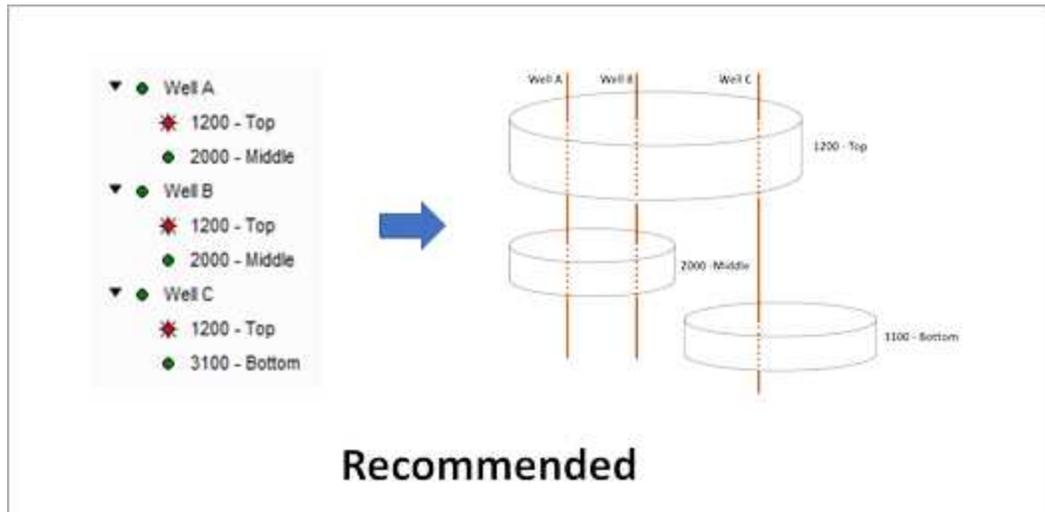
Relationship between layer entities and layers of the CMW model

For Harmony Enterprise 2022.2 and later, you can create multilayer wells by adding layer entities in the Entity Viewer.

When creating a multi-well model for a set of multilayer wells, there is no requirement for the layers in the Entity Viewer and the layers in the CMW model to be consistent with each other.

However, we recommend keeping the layer structure and naming consistent because it makes using this analysis easier.

If you decide to have consistency in the layer structure and layer naming between layers in the Entity Viewer and layers in CMW, it is your responsibility to keep layer naming consistent. (Harmony Enterprise does not require nor enforce this consistency.)



If the layers in the Entity Viewer are set up and have appropriate layer information, you can set up the multilayer CMW model:

- After creating the CMW model (see [model creation](#)), click the **Reservoir & Layers** button.
- To add model layers, click the **Set Up Model Layers Based on Layer Entities** () icon in the toolbar. Layer names, datums, and properties are populated based on the information available in the editors for the multilayer well and its layer entities.

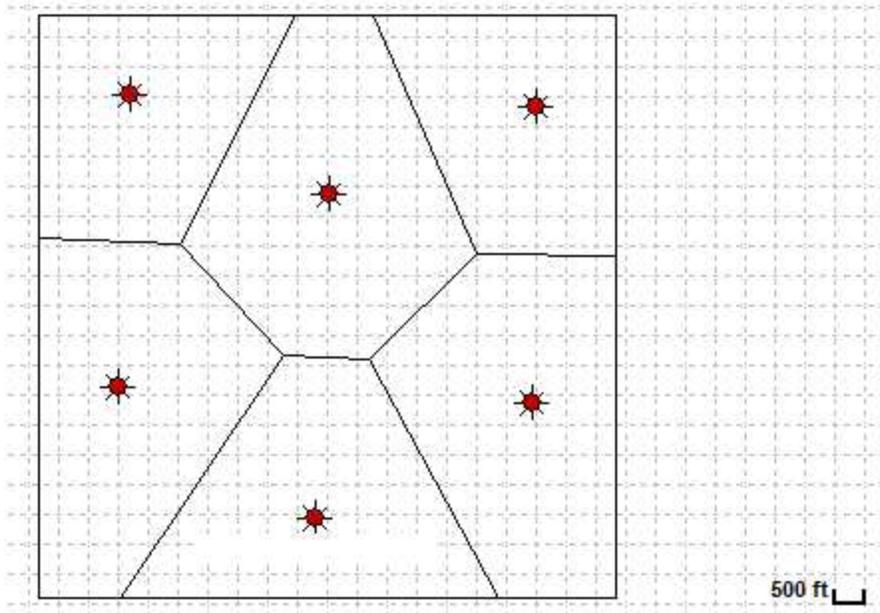
- Well Rate Time plots for the CMW model display historical layer rates, and historical layer calculated sandface pressures that are available in the Production editor for layer entities. These historical data points are not used in the model's calculations, but are displayed so that you can visually compare historical data and data simulated by the model.
- If you do not have confidence in the allocation data that is set up in the Multilayer Allocation editor, you may want to overwrite it by the layer allocations generated by this model. The data in the Tables \ Well – Allocations tab can be directly copied and pasted to the Multilayer Allocation editor of the well.

Model geometry

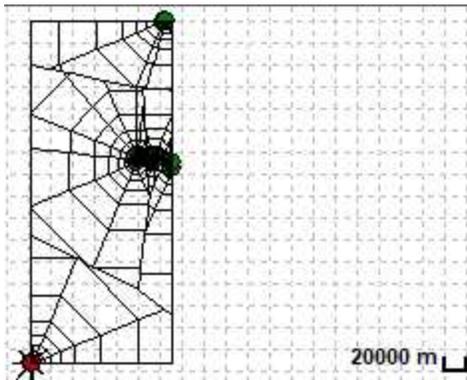
This analysis currently supports vertical, vertical with fracture, and horizontal well completions. Wells are placed in the reservoir according to their actual locations (specified by sandface lat / long in the Attributes tab). Length and direction of horizontal wellbores are drawn according to L_e and Azimuth parameters.

Reservoir boundaries default to 1,320 ft (a 1/4 section) from the outermost wells. These boundaries can be adjusted using the  and  icons. For more information, see the Side Schematic plot toolbar description.

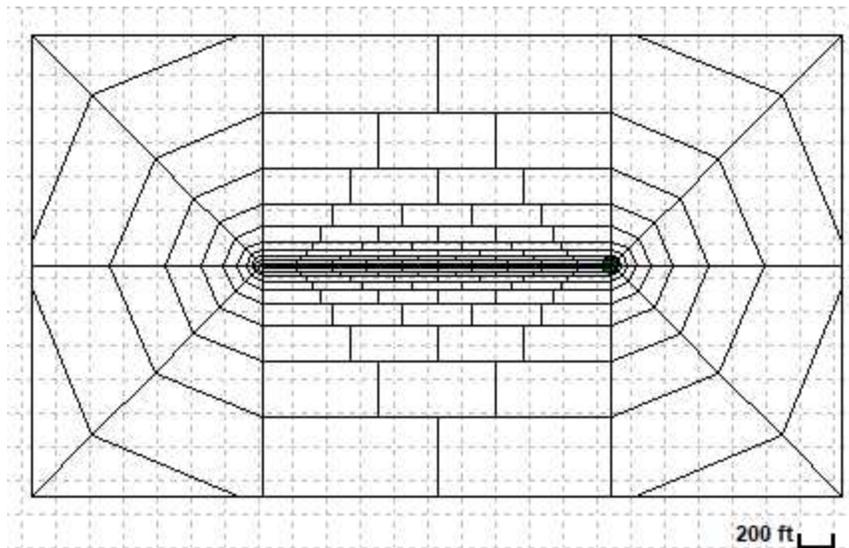
This is a reservoir with well regions:



These are vertical wells with cell regions:



This is a horizontal well with cell regions:



Setting model parameters

Well regions are automatically created for the model by drawing boundaries halfway between adjacent wells. These regions are used for setting parameters, such as net pay and permeability in the grid cells of each region. They do *not* represent no-flow boundaries.

To specify the properties for each region, select the well by clicking it in the schematic, or select the well from the drop-down menu, or use the arrows in the primary toolbar. When you click the **Wells** button, you can manually enter properties, or click the **Pull Defaults** icon in the primary toolbar to use values from analyses in the well.

The initial pressure, bubble-point pressure, compressibility, and area are specified in [Reservoir & Layers](#), and are applied to the entire reservoir. If you have the Properties editor populated for the group before creating the Multi-well model, this information is pre-populated when the worksheet is created.

Primary toolbar

The primary toolbar has the following icons:

-  **Pull Defaults** — select from these options:
 - **Group Properties** — copies default values from the [Properties editor](#) of the group.

- **Selected Well Properties** — copies default values from Properties editor of the selected well.
- **Group Analysis** — displays a sub-menu with all the other conventional multi-well models for the group. (If there are no other conventional multi-well models, this option is not displayed.) Selecting one of the existing models copies one multi-well model to another in the same group, which can be useful if you want to experiment with the copy of the model while preserving the original content. Note that the parameters on the Forecast tab are not copied.
- **Selected Well Analysis** — displays a sub-menu with all the analyses (that is, typecurve, analytical, and numerical) for the selected well. (If there are no other analyses, this option is not displayed.) Selecting one of the existing analyses, copies parameters of that analysis to the currently selected well.
- **Another Well in this Model** — displays a sub-menu with all the other wells in the same model. Select one of the wells to copy the calculation method, well parameters, and constraints from that well to the currently selected well (displayed in Wells under Selected Well).
-  **Push Defaults** — copies well parameters from the currently selected well to the one other well you select, or to **All Wells** in the model. Selecting **Model Parameters** copies all parameters set under the Plots Tab \ Wells; selecting **Forecast Parameters** copies parameters set under the Forecast tab for the currently selected well.
-  **Bulk Edit Geological Parameters** — opens a summary table of layers and wells for quick editing, including renaming layers. If you update a parameter value, the text changes to black (from gray). You can update parameters individually, or you can update, for example, net pay or porosity for a layer and all the associated wells. You can also copy and paste to Excel and vice versa. To accept your changes, click the **Apply** button. To discard your changes, click the **Cancel** button.

-  **Synthesize** — click this icon every time you want to history-match and create a forecast.
-  **Stop Synthesize** — stops the model's synthesize calculations.
-  **Previous Well** — jumps to the previous well.
-  **Next Well** — jumps to the next consecutive well.
-  **Copy to / Paste from Clipboard** — copies / pastes entity parameters from the clipboard.
-  **Event Scheduler** — opens the Event Scheduler where you can model opening and closing of individual layers.
- Playback icons ()

After you click the **Synthesize** icon () in the primary toolbar and the calculations are complete, the icons listed below are enabled in the same toolbar. With these playback icons, you can see how pressures or saturations change through time. A tooltip displays the pressure or saturation value and unit, as you hover over your color-shading plot.

-  **Skip to Beginning** — displays the first timestep.
-  **Step Back One Frame** — view timesteps in reverse one frame at a time.
-  **Play in Reverse** — view timesteps in reverse. You can click this icon multiple times to increase the speed of the playback.
-  **Stop** — stops the playback process. As you hover over various cells in your well, the pressure or saturation is displayed.
-  **Play** — view timesteps from start-to-finish. You can click this icon multiple times to increase the speed of the playback.

-  **Step Forward One Frame** — view one frame at a time.
-  **Skip to End** — displays the last timestep.

Plots tab

This tab displays four plots in a dashboard and has these buttons in the lower left: Wells, Reservoir & Layers, Volumes, and Options. If you do not see all these buttons, click >> and select **Show All Buttons**.

Wells

In Wells, you can specify model parameters for each individual well, for every layer that it penetrates.

The screenshot shows a software interface for well management. At the top, there are two tabs: 'Plots' and 'Forecast'. Below the tabs, there is a 'Selected Well' dropdown menu currently set to 'Hz3'. Underneath, there are two radio buttons: 'Use Production Rate (Oil)' (which is selected) and 'Use Pressure'. Below these, there is a text input field for 'Vw' with the value '820.852' and a unit 'ft³'. A section titled 'Advanced Well Control' is expanded, showing several parameters with their values and units: 'h' (130.8 ft), 'ht' (13.30%), 'Sg' (0.00%), 'So' (75.00%), 'Sw' (25.00%), 'kxy' (0.4959 md), and 'kz/kxy' (0.100). Below this, there is a 'Completion Type' dropdown menu set to 'Horizontal'. Underneath, there are more parameters: 'La' (2132.9 ft), 'Azimuth' (341.6°), 's' (0.00), and 'rw' (0.350 ft). At the bottom of the interface, there is a blue bar with a red star icon and the text 'Wells'.

Selected Well – select the well you want to modify from the drop-down list.

Parameters located below the Selected Well drop-down list apply to the selected well:

- Select if this well is to be operated at a production rate or a pressure control.
- V_w – the wellbore volume of the portion of the wellbore that goes from the top layer of the wellbore to the surface. (Wellbore volumes for the portions of the wellbore below the top layer are calculated based on given dimensions.)
 - Modify Advanced Well Control parameters, if required.

Advanced Well Control

Include — by default, all wells in the group are included in the model. Deselect Include to exclude the selected well from the model (it is modeled as a shut-in well). If the well is excluded, you still need to set up valid parameters for it; the geometry of the well region is still being used to generate a grid used in the model. However, if the well is excluded, its production is not taken into account.

Calculation Method for Production — specify what rate (gas, oil, or water) should be used for well control and set p_{min} , which is the minimum flowing pressure allowed during production. Or, you can choose to operate the well at pressure control. In this case, you can set $(q_g)_{max}$, $(q_o)_{max}$, and $(q_w)_{max}$, which are the maximum rates allowed during production.

Calculation Method for Injection — if you have injection rates for your well in the Production editor, the Calculation Method for the Injection section is displayed, and you can set controls to be used during injection.

Below Advanced Well Control parameters are parameters describing geology and completion in each of the layers. All of the layers are listed in order from the shallowest to the deepest one. Select the layer you want to edit, and a corresponding group of parameters expands. (To select a layer, you can either select click an arrow to the left of the Layer name (▶), or you can change your layer selection in the [Side Schematic plot](#).) If the model has just one layer, a well's geological and completion parameters are always displayed.

Note: To add a new layer, rename, or delete layers, click the [Reservoir & Layers button](#).

Geological parameters:

- h — net pay
- ϕ_t — total porosity
- S_g — gas saturation
- S_o — oil saturation
- S_w — water saturation
- k_{ay} — permeability in the horizontal direction
- k_z/k_{xy} — permeability ratio (permeability in the vertical direction / permeability in the horizontal direction)

Completion parameters:

(These parameters apply to the completion of the selected well in the selected layer.)

- Use the **Completion Type** drop-down list to select either **Vertical**, **Horizontal**, **Vertical with Fracture**, or **No Perforation**.

If you select **Vertical**, these parameters are displayed:

- s — skin
- r_w — wellbore radius

If you select **Horizontal**, these parameters are displayed:

- **Le** — type your effective horizontal well length. (By default, L_e is calculated based on the perforation data set up in the Wellbore editor.)
- **Azimuth** — is the angle between North and the horizontal portion of the wellbore. Type your value in degrees. (By default, this value is calculated based on your deviation-survey data in the Wellbore editor, as long as it contains easting and northing data.)
- s — skin
- r_w — wellbore radius

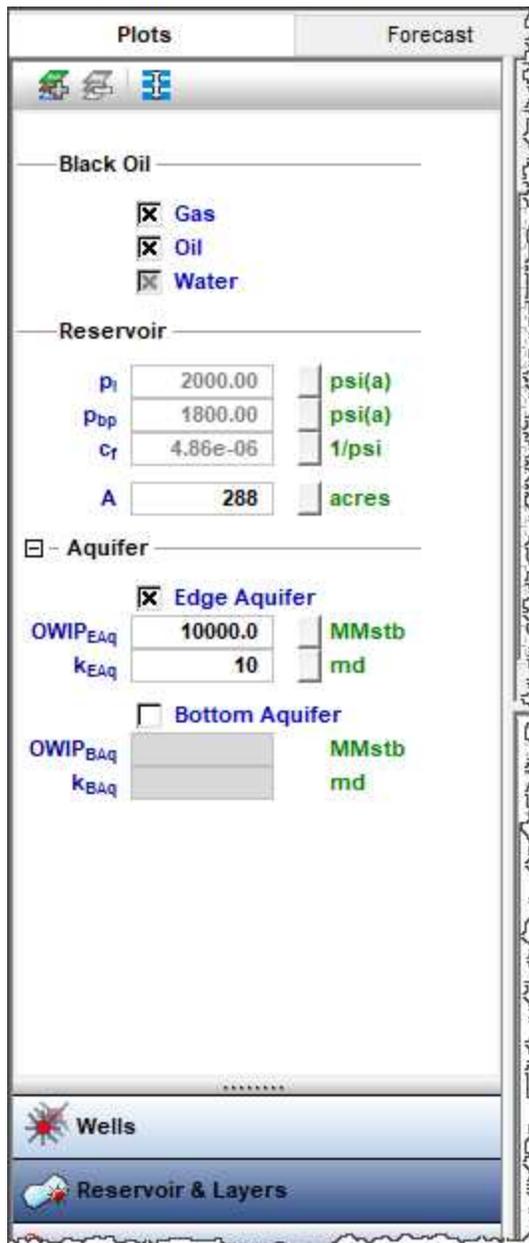
If you select **Vertical with Fracture**, these parameters are displayed:

- x_f — fracture half length
- **Azimuth** — is the angle between North and the wellbore, in degrees
- F_{CD} — dimensionless fracture conductivity
- $k_f w_f$ — fracture conductivity
- s_f — damage skin on fracture face
- r_w — wellbore radius

If you select **No Perforation**, no completion parameters are displayed.

Reservoir & Layers

When you click the **Reservoir & Layers** button, you can specify parameters that are used for the entire reservoir and layers.



Note: For additional information about the way multiple layers are modeled, see the [CMW model](#).

Toolbar icons

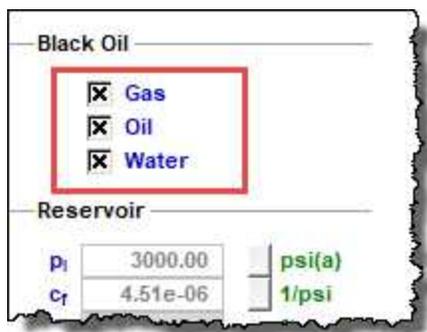
Toolbar icons are as follows:

-  **Add New Layer** — opens the Add Layer dialog box where you type a layer name and datum depth (true vertical depth in the middle of the layer).
-  **Remove Selected Layer** — deletes the currently selected layer. You are not prompted to confirm your decision.
-  **Set Up Model Layers Based on Layer Entities** — adds a set of layers to the model, based on the layer entities that exist for the wells in the group. Layer name and some of their properties are populated based on the information available for the corresponding layer entities.

To rename layers, click the **Bulk Edit Geological Parameters** icon () in the primary toolbar. For more information, see [Bulk Edit Geological Parameters dialog box](#).

Fluid type selection

Click the checkboxes for the fluid phases you want to include in your model: **Gas**, **Oil (or Condensate)**, and/or **Water**.



Selected Layer

In this section, select a layer from the drop-down list to view or modify these parameters: datum, initial reservoir pressure, and drainage area.

Note: If there is only one layer, this section is not displayed.

Aquifer

Aquifers are defined per layer, and parameters are displayed for the currently selected layer. In the Aquifer section, you can have an aquifer edge, bottom, or both. In order to account for an

aquifer in your reservoir, you need to connect it. For more information, see the [Connect Aquifer icon description](#).

If you select **Edge Aquifer**, you must specify values for $OWIP_{EAq}$ and k_{EAq} .

If you select **Bottom Aquifer**, you must specify values for $OWIP_{BAq}$ and k_{BAq} .

The screenshot shows a configuration panel for an aquifer. At the top, there is a checkbox labeled 'Aquifer' which is checked. Below this, there are two sections for aquifer types, each with a checked checkbox:

- Edge Aquifer:**
 - $OWIP_{EAq}$: 21.00 (unit: $10^6 m^3$)
 - k_{EAq} : 21 (unit: mD)
- Bottom Aquifer:**
 - $OWIP_{BAq}$: 21.00 (unit: $10^6 m^3$)
 - k_{BAq} : 32 (unit: mD)

Volumes

When you click the Volumes button, read-only values for the reservoir and layers are displayed.

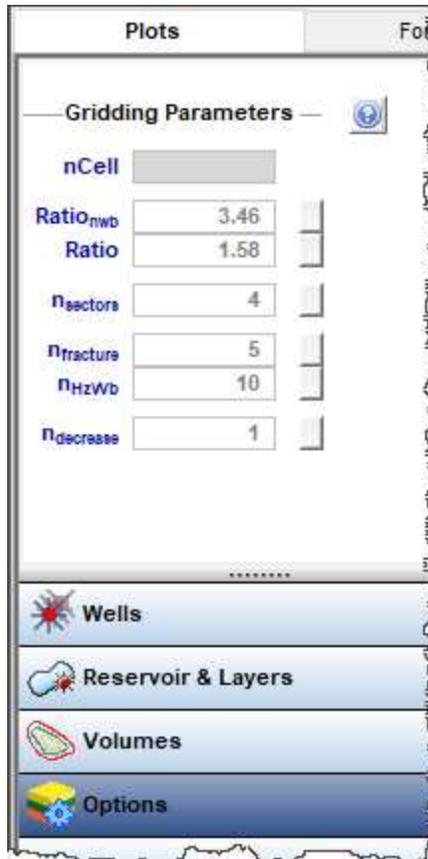
The screenshot shows the 'Volumes' panel. At the top, there is a 'Plots' section. Below it, there are two sections: 'Reservoir' and 'Layer'. Each section contains a list of volume parameters with their values and units. At the bottom, there is a navigation menu with three buttons: 'Wells', 'Reservoir & Layers', and 'Volumes'.

Reservoir		
OGIP _F	0	MMscf
OGIP _S	31464	MMscf
OGIP	31464	MMscf
OOIP	55601.4	Mstb
OWIP	47053.2	Mstb

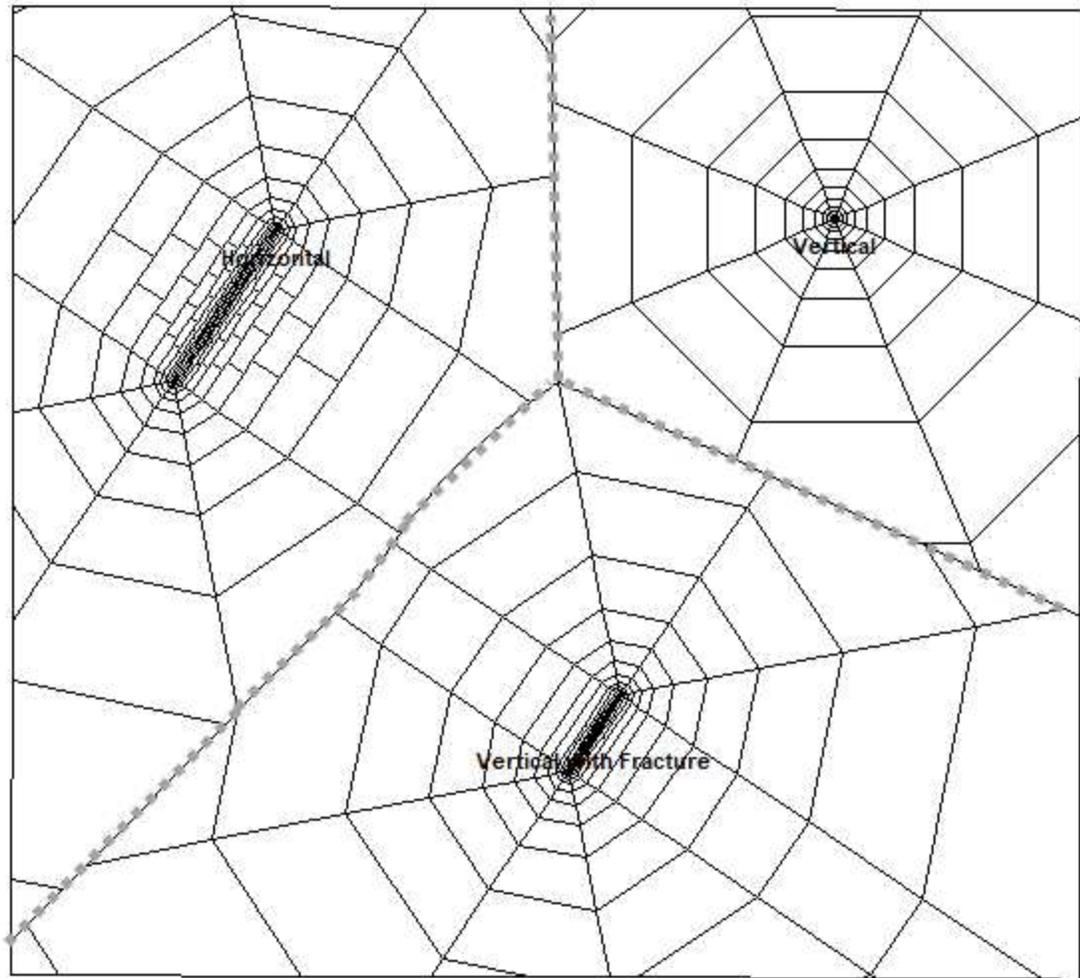
Layer		
OGIP _F	0	MMscf
OGIP _S	21368	MMscf
OGIP	21368	MMscf
OOIP	37759.9	Mstb
OWIP	31961.3	Mstb

Options

When you click the **Options** button, various gridding parameters are displayed.

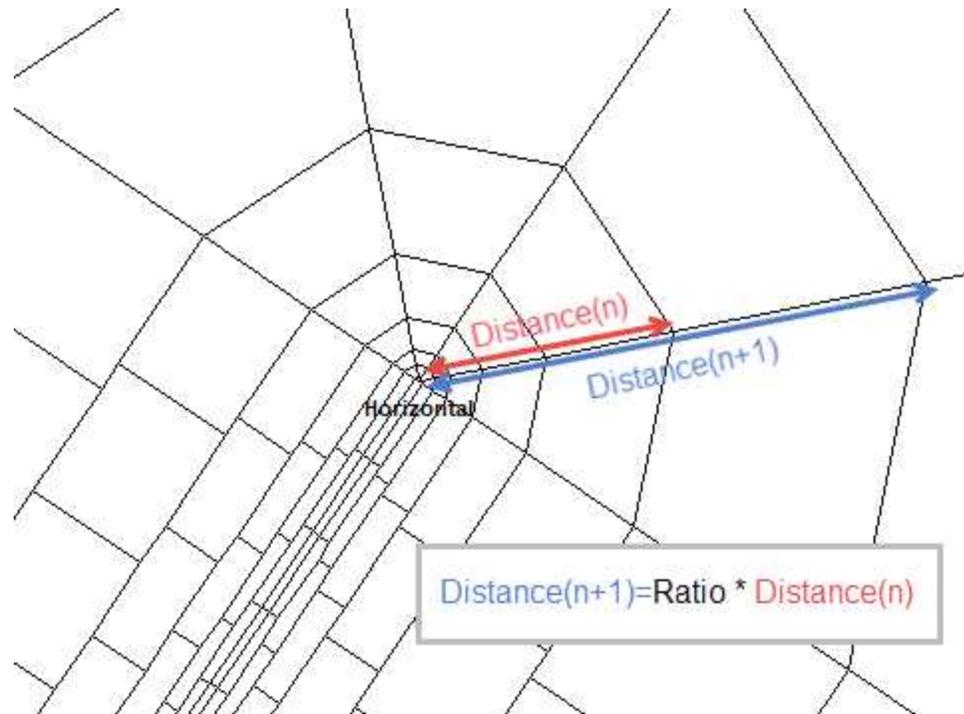


After you set your reservoir dimensions, well locations, layers, and well completion parameters, the CMW model creates an appropriate grid to get accurate results with minimal calculation time. To display gridding, right-click the schematic plot and select **Show Grid Cells**.



Usually, the default gridding settings are fine, but in some cases, you may want to adjust the gridding parameters. Gridding parameters are as follows:

- **Ratio_{nwb}** — controls the size of the cells adjoining wellbores and fractures.
- **Ratio** — controls the rate at which cell sizes increase as they go further from the completion.



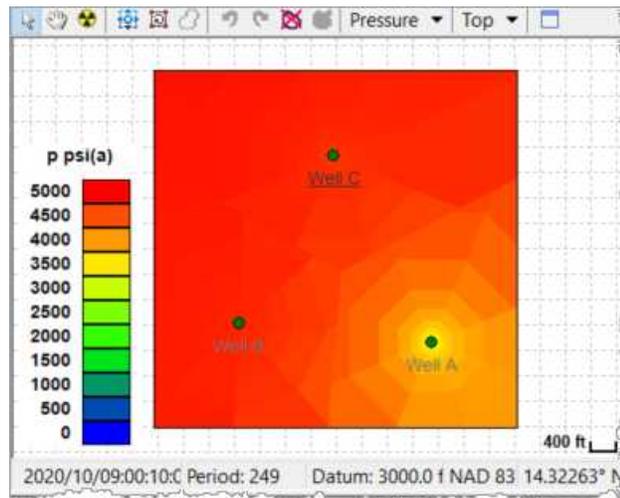
- $n_{sectors}$ — the number of sectors used for the radial portion of the gridding. In the figure above, $n_{sectors} = 4$, so each half-circle is divided into four sectors.
- $n_{fracture}$ — the fracture has one wellbore cell in the middle, and each wing of the fracture is divided into $n_{fracture}$ equal parts.
- n_{HzWb} — the horizontal wellbore is divided into n_{HzWb} equal parts.
- $n_{decrease}$ — the row of cells adjoining the completion is divided into equal cells. The number of cells is equal to $2 * n_{fracture}$ for fracture completions and is equal to n_{HzWb} for horizontal completions. For each subsequent row, the number of cells decrease by $n_{decrease}$.

Dashboard

In the dashboard, there are four plots, which are described below. You can switch which plots (that is, Map View, Side Schematic, Well Rate Time, Total Rate Time, and Ratios) are displayed in the dashboard by clicking the **Change Plot** button in each plot's toolbar.

Map View

The map view is always displayed in the dashboard and displays one layer at a time. You can edit / rotate your reservoir, display shapefiles, view / edit your aquifer, and view shaded plots while you run a simulation.



Toolbar icons are as follows:



Edit Reservoir Boundary — click-and-drag to move your reservoir. Scroll your mouse wheel to expand or shrink your reservoir. White circles move an entire edge of the reservoir boundary. Red squares move only the selected vertex. Click a mid-section of a reservoir edge to add a new red vertex; note that your cursor changes to a cross.



Rotate Reservoir — scroll your mouse wheel, or use your keyboard's arrow keys to rotate the boundaries of your reservoir (the physical location does *not* change) around the reservoir center. To rotate your reservoir around your cursor, press the **Ctrl** key and scroll / use your arrow keys.



Display Reservoir Boundary from Spatial Explorer — opens the Available Polygon Layers from Spatial Explorer dialog box where you can select or create a polygon layer in Spatial Explorer. This polygon replaces the existing model boundaries automatically. For more information, see Spatial Explorer.



Undo — undoes your last action. (You cannot undo your zoom as this icon applies to resizing only.)



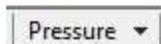
Redo — reapplies the size of your reservoir to your previous settings. (You cannot redo your zoom as this icon applies to resizing only.)



Reset Reservoir Boundary — resets your reservoir size to the default setting.



Connect Aquifer — this icon is available if **Edge Aquifer** or **Bottom Aquifer** are selected in **Reservoir**. Click this icon to set the parts of the reservoir boundary that are connected to the edge or bottom of the aquifer. Segments of the boundary that are highlighted in blue are connected to the edge of the aquifer. By default, the entire reservoir boundary is connected to the aquifer, but you can select and deselect edges by clicking them. Cells that are highlighted in blue are connected to the bottom of the aquifer. (The mouse cursor becomes blue when you are in connect-aquifer-selection mode.) You can also select **Connect All to Aquifer** or **Deselect All from Aquifer** for your cell regions by right-clicking the schematic.



Shaded Plot Display Mode — this drop-down list becomes available after the model has been synthesized. Use this drop-down list to select which property you want to display in each grid cell. You can select one of the following properties to display it: Pressure, Saturations (color scheme based on saturations of all three phases), Gas Saturation, Oil Saturation, Water Saturation, Permeability, Net Pay, or Porosity.

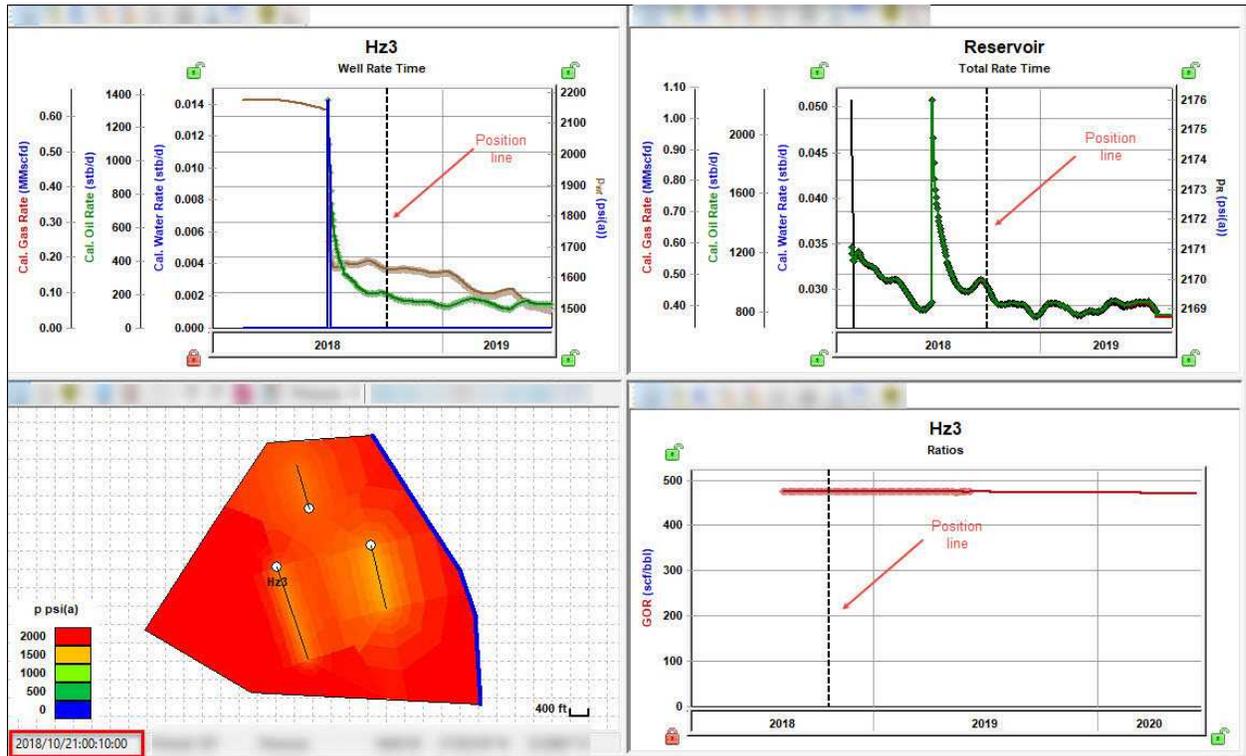


Currently Selected Layer — select the layer you want to display.

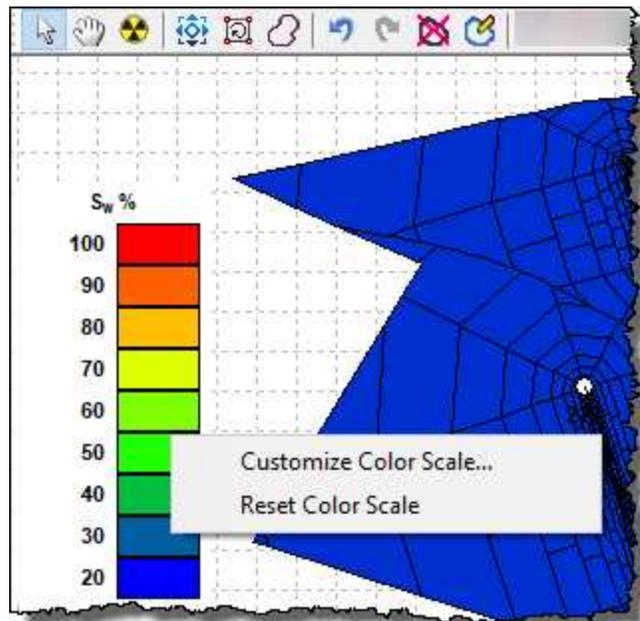
For information on common plot icons, see [plot toolbars](#).

After you click the **Synthesize** icon () in the primary toolbar, the synthesis proceeds. Lines representing simulation results are drawn as the simulation progresses.

Position lines indicate calculation progress. The shaded plot displays the distribution of pressure or saturation at the timestep that has just been calculated (as indicated by the time-stamp in the lower left corner, which displays the exact date and time). After the calculation is completed, these Position lines can be dragged to the moment in time you want to examine more closely, and all plots are synchronized.



If you find that the color scale for your shaded plot needs adjusting, right-click the legend and select **Customize Color Scale**, and then type customized min and max values. To revert back to the default min and max values, right-click the legend and select **Reset Color Scale**.



Note: After you click the **Shaded Plot Display Mode** drop-down list and select an option, you can view values for each cell region by hovering over the shaded plot. Tooltips are displayed for each cell region.

Context menu

Right-clicking lists these options:

- **Reservoir Region** — show / hide the reservoir boundary.
- **Wells** — show / hide the wells in the reservoir.
- **Well Names** — show / hide the well names in the reservoir.
- **Well Regions** — show / hide the boundaries of the well regions.
- **Cell Regions** — show / hide the grid cell boundaries for each well in the reservoir.
- **Selected Well** — show / hide the well name for the selected well.
- **Scale Gridline** — show / hide gridlines with a scale marker.

- **Connect All to Aquifer** — when **Bottom Aquifer** has been selected in the Aquifer section of Reservoir & Layers and you are in aquifer-selection mode, you can select all of the cell regions at once by selecting this option.
- **Disconnect All from Aquifer** — when **Bottom Aquifer** has been selected in the Aquifer section of Reservoir & Layers and you are in aquifer-selection mode, you can deselect all of the cell regions at once by selecting this option.
- **Copy Lat / Long to Clipboard** — copies the latitude and longitude of the current position of the mouse pointer. These latitude / longitude values can be used to add a new infill well at the location you want:
 - Move the mouse pointer to the location for the new infill well; then, right-click and select **Copy Lat / Long to Clipboard**.
 - Create a new well using the Entity Viewer - Hierarchy. For more information, see adding an entity.
 - Open the Attributes tab for this well and paste the surface latitude and longitude from the clipboard.
 - Add this new well to the multi-well group previously used to run the multi-well analysis. (You can drag-and-drop the new well from the Entity Viewer - Hierarchy to the Entity Viewer - Custom.)

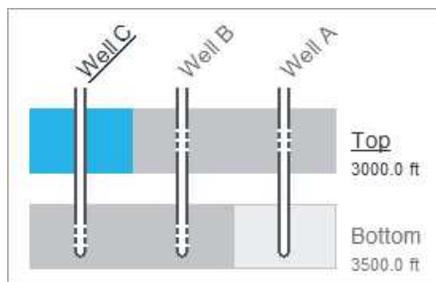
Side Schematic

This plot displays a schematic view of the model, displaying all its layers and wells. The elements in this plot are not drawn to scale; rather, this plot can be thought of as a navigation tool. At any given time, one well and one layer are selected. In the schematic view, the names for a currently selected well and layer are underlined. Also, the well region of the selected well at the selected layer is indicated by a blue rectangle.

You can change your well and layer selections by clicking elements in this schematic. All of your selections are synchronized with other areas in the interface where you can change your well and layer selections. For example, if you select Well C and Top layer in the Side Schematic (as shown below), parameters in Wells are displayed for Well C and Top layer.

Additionally, you can use schematics to determine if a well is outside the boundary of a certain layer (for example, Well A is outside the boundary of the Bottom layer, and the corresponding well region is displayed in light gray). The schematic also indicates whether the well is completed

at a particular layer (for example, Well C is completed at the Bottom layer, but not in the Top layer).



Note: White horizontal lines indicate perforations.

Ratios plot

This plot displays historical and simulated ratios for the selected well.

For a description of common icons, see [toolbars](#). Be aware of this additional icon:

 **Show or Hide Well and Layer Data** — select to display calculated datasets only for the **Well** (thick lines), only for the **Layer** (thin lines), or for both **Well and Layer** (thick lines for Well, thin lines for Layer). If the well has a layer entity with the same name as the layer in the model, its historical datasets (ratios) are also displayed on the plot (with smaller-sized points for layer datasets).

Points on the plot represent the following:

- Larger points represent historical total ratios for the entire well (that is, red = GOR, green = CGR, blue = WGR or WOR).
- If the model has multiple layers, smaller points represent historical ratios for the currently selected layer (same color designation). Note that historical datasets for the layer are only displayed if the well has a layer entity with the same name as the layer in the model.

Lines on the plot represent the following:

- thick lines represent total ratios for the entire well (that is, red = GOR, green = CGR, blue = WGR or WOR).
- If the model has multiple layers, thin lines represent the value for the currently selected layer (same color designation).

Well Rate Time plot

This plot displays historical and simulated rates, as well as pressure for a single well.

For a description of common icons, see [toolbars](#). Be aware of these additional icons:

-  **Show or Hide Gas / Oil / Water** — toggle between the fluids you want displayed.
-  **Switch to Rate vs Time / Switch to Cumulative vs Time** — toggle between these two views.
-  **Show or Hide Well and Layer Data** — select to display calculated datasets only for the **Well** (thick lines), only for the **Layer** (thin lines), or for both **Well and Layer** (thick lines for Well, thin lines for Layer). If the well has a layer entity with the same name as the layer in the model, its historical datasets (rates and sandface pressures) are also displayed on the plot (with smaller-sized points for layer datasets).
-  **Show / Hide Interpolated Layer Rates** – available for multilayer CMW models. If the well has a layer entity with the same name as the layer in the model, its historical datasets (rates and sandface pressures) are displayed on the plot. This icon toggles between displaying historical layer data for all dates or only for the dates entered in the [Multilayer Allocation editor](#).

To switch wells, you can:

- Click the arrows ( ) in the main toolbar.
- Click a well in the Map View.
- Click a well in the Side Schematic plot.
- Select a different well from the **Select Well** drop-down list.

For a description of its common icons, see [toolbars](#).

Points on the plot represent the following:

- Larger points on the plot represent well historical data (red = gas rate, green = oil rate, blue = water rate, brown = sandface flowing pressure).
- If the model has multiple layers, smaller points represent historical data for the currently selected layer (same color designation). Note that historical datasets for the layer are only displayed if the well has a layer entity with the same name as the layer in the model.

Lines on the plot represent the following:

- Thick lines represent the value for the well (red = gas, green = oil, blue = water, brown = flowing pressure).

Note: Well flowing pressure is a flowing pressure at the very top layer penetrated by the well.

- If the model has multiple layers, thin lines represent the value for the currently selected layer (same color designation).

Total Rate / Cum Time plot

This plot displays the total historical and simulated rates / cumulative production for the entire reservoir, and the reservoir pressure.

For a description of common icons, see [toolbars](#). Be aware of these additional icons:

-  **Show or Hide Gas / Oil / Water** — toggle between the fluids you want displayed.
-  **Switch to Rate vs Time / Switch to Cumulative vs Time** — toggle between these two views.
-  **Show or Hide Total and Layer Data** — select to display calculated datasets only for the **Total** of the entire group (thick lines), only for the **Layer** (thin lines), or for both **Total and Layer** (thick lines for Total of the entire group, thin lines for Layer). If some wells in the model have layer entities with the same name as the layer in the model, historical rates for these layer entities are summed up and also displayed on the plot (with smaller-sized points for layer datasets).

This plot displays the total historical and simulated rates / cumulative production for the entire reservoir and the reservoir pressure.

Points on the plot represent the following:

- Larger points on the plot represent historical data for the entire group (red = gas rate, green = oil rate, blue = water rate).
- If the model has multiple layers, smaller points represent historical data for the currently selected layer (same color designation). Note that historical data-sets for the layer are only displayed if some wells in the model have layer entities with the same name as the layer in the model.

Lines on the plot represent the following:

- Thick lines represent the value for the entire reservoir (red = reservoir gas rate, green = reservoir oil rate, blue = reservoir water rate).
- If the model has multiple layers, thin lines represent the rates produced by all of the wells from the currently selected layer (same color designation).
- A turquoise line represents average reservoir pressure, or average pressure for the currently selected layer in a multilayer case.
- If the model has multiple layers, average reservoir pressure is not displayed by default. To display average reservoir pressure, right-click the plot and select **Customize Datasets**.

Forecast tab

This tab has the same features as the numerical Forecast sub-tab, but you have the option to display all wells in the group, or individual wells.

Forecast Plot

If **All Wells** is selected in the Select Well drop-down list, the Forecast plot displays group-level rates and reservoir pressures. If one of the wells is selected in the Select Well drop-down list, the Forecast plot displays rates and flowing pressures for that selected well.

Forecast Options

Use the Select Well drop-down list to pick any individual well or All Wells. Select one of the wells to see forecast settings for just that well in the Forecast table, or select **All Wells** to see forecast settings for all the wells together.

The Forecast Start Date is set for the entire model (the forecast for *all* the wells starts at this given date).

The values in the Duration column are shared between all the wells in the model.

Forecast Constraints are applied for all of the wells in the model.

After you set up a valid forecast and synthesize it, the Forecast Results table displays EUR, RR, RF, and historical volumes for each well for each of the fluid phases available in the model.

Forecast Injection

To forecast injection for any well, select one of these options from the **Control Type** drop-down list:

- **Gas Inj Rate** — the forecast at a given gas injection rate.
- **Water Inj Rate** — the forecast at a given water injection rate.
- **Pressure (Inj Gas)** — the forecast at a given sandface flowing pressure. (This pressure is reached by injecting gas.)
- **Pressure (Inj Water)** — the forecast at a given sandface flowing pressure. (This pressure is reached by injecting water.)

Note: In order for the above options to be available, the corresponding fluid phase must be selected when you click the **Reservoir & Layers** button.

Injection constraints are applicable when at least one of the wells has an injection forecast.

- $(p_{inj})_{max}$ — sets a maximum sandface flowing pressure during the forecast. In order to maintain the maximum flowing pressure, the injection rate is adjusted.
- $(q_{ginj})_{max}$ — sets a maximum gas injection rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted.
- $(q_{winj})_{max}$ — sets a maximum water injection rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted.

Toolbar

This toolbar has the same common icons described in [plot toolbars](#).

Tables tab

This tab displays calculated data in table format in the following sub-tabs:

- **<well name>** — displays information (calculated rates, cumulative production, ratios and sandface flowing pressures) for the selected well.
- **Total** — displays information for the entire group.
- **Run** — displays reservoir pressures and average saturations for the entire model.
- **<layer name>** — displays information for the currently selected layer of the selected well.
- **<well name> - Allocations** — only available for multilayer CMW models. This tab contains allocations for the fluid rates for the selected well between its layers. Content in this tab can be directly copied and pasted to the Multilayer Allocation editor of the well (assuming the layer naming is consistent).

Bulk Edit Geological Parameters dialog box

This dialog box opens when you click the **Bulk Edit Geological Parameters** icon () in the conventional multi-well's primary toolbar.

This dialog box displays a summary table of geological parameters for all wells in all layers. You can do the following:

- For individual parameters, type new parameter values in corresponding cells
- Set up parameter values for all of the wells in the layer by typing a Layer Value. For example, to set porosity for the entire Top layer to 12%, type 12 in the **Layer Value** column for the porosity of the layer. Porosity values for individual wells in this layer update accordingly.
- Multiply all of the values for a parameter within the layer by the same number by typing a Multiplier. For example, if you type 1.1 in the **Multiplier** column for k_{ay} for the Top layer, permeabilities for this layer become:
 - $20 * 1.1 = 22$ for Well A
 - $25 * 1.1 = 27.5$ for Well B
 - $27 * 1.1 = 29.7$ for Well C
- Copy and paste values (for example, to and from Excel).
- Rename layers.

Note: Parameters values that have been changed in this dialog box are indicated with black text.

Event Scheduler dialog box

This dialog box opens when you click the **Event Scheduler** icon () in the conventional multi-well's primary toolbar.

For single-layer cases to model well shut-ins, set fluid rates to zero in the Production editor, or as a forecast constraint.

For cases when the well is producing from multiple layers, it may be that different layers are opened or closed at different times. For example, the well may produce from one layer initially, but get completed from another layer later.

Whenever a connection is closed (for example, because the well is excluded, or because the completion type for a particular layer is "No Perforation", or due to a Close event), flowing pressure for the well at this layer is reported at the reservoir side, *not* at the wellbore side. There is only *one exception* to this rule: when the top-most completion of the well is temporarily closed (by a Close event), the Event Scheduler displays calculated flowing pressure for this layer and for the well at the wellbore side, not at the reservoir side.

To add an event:

1. Set your well name, layer name, type of event (that is, Open or Close), and event date.

You can select values for required fields from the drop-down lists, or you can paste data (for example, from Excel). Pasting is particularly convenient if you have information about multiple events already summarized in a file.

2. After you set all the events for the model, click **OK**.

When you calculate the model, these events are honored.

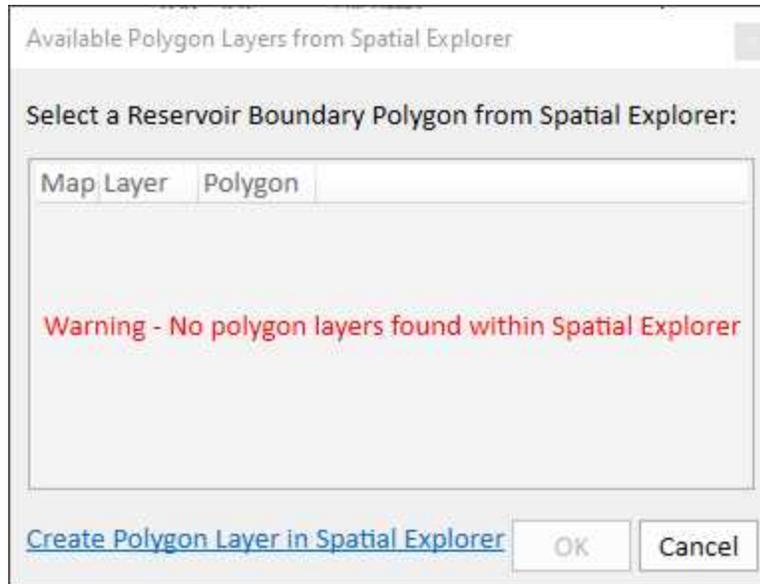
Note: During drawdowns, all layers are considered open, unless there is a "close" event. During shut-ins, the well is assumed to be producing at rate control ($q=0$), even if there are "open" events for some of the layers.

Editable polygon layers in Spatial Explorer

Editable polygons can be imported from Spatial Explorer to automatically define boundaries in Harmony Enterprise. When Importing the polygon to CMW, the layer displayed on the map is the

only one that has modified boundaries.

If you do not have any polygon layers In Spatial Explorer, a blank dialog box is displayed.

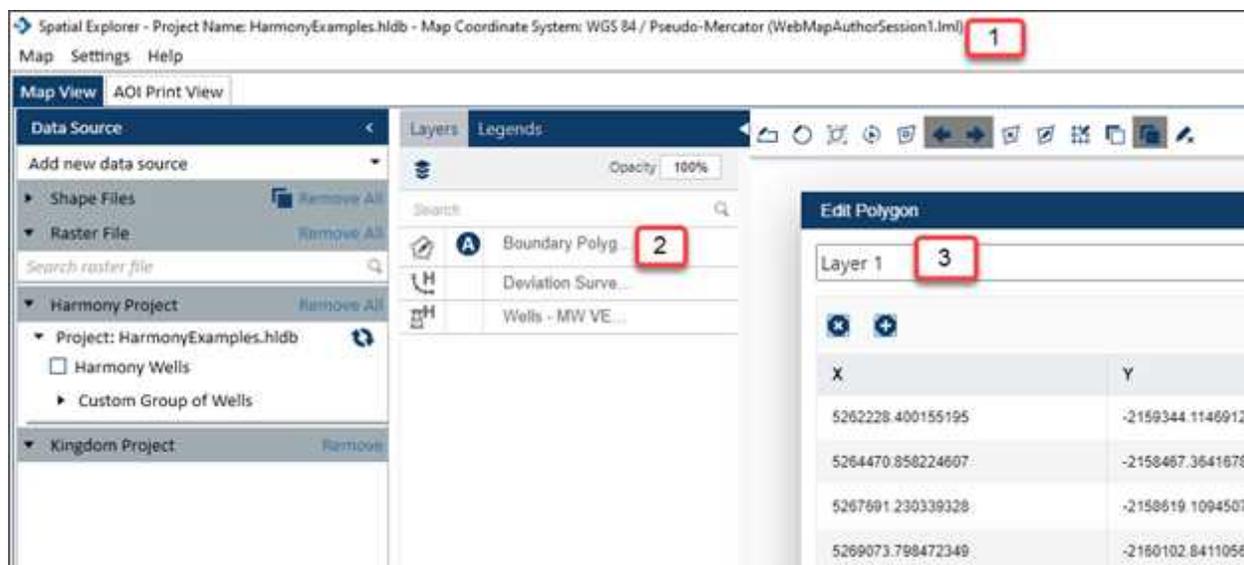
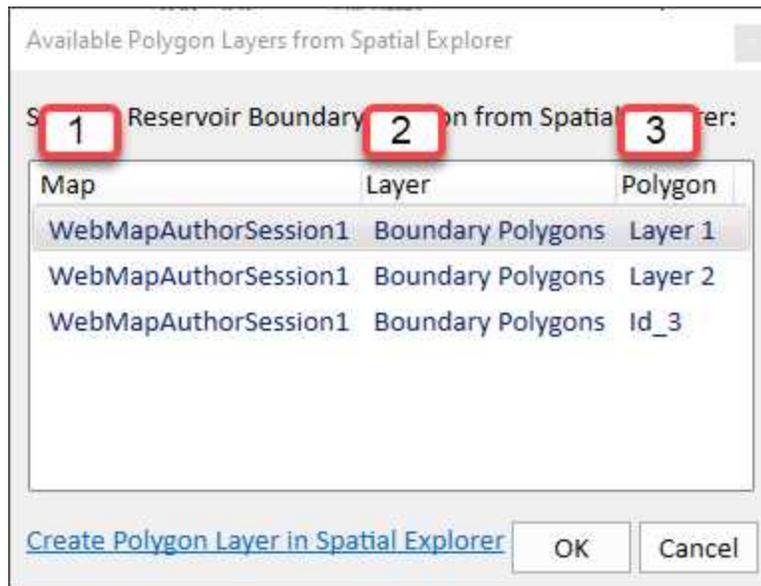


You can add and modify polygons on the Spatial Explorer map by adding an editable polygon layer and then creating new polygons on this layer. For more information, see [adding editable polygon layers](#) (opens a topic in the Spatial Explorer help).

After polygon layers have been created, they are sorted by:

1. session
2. layer name
3. polygon name

Note how polygon layers are labeled in Harmony Enterprise and Spatial Explorer.



In addition to manually creating polygons In Spatial Explorer, you can automatically generate them from other layer types after the layer Is active and selected. For more information, see [creating editable polygon layers](#) (opens a topic in the Spatial Explorer help).

Unconventional multi-well model

With the unconventional multi-well (UMW) module, you can simulate multiple horizontal multistage fracture wells using the *group* numerical model to history-match producing wells and forecast future production. With this analysis, wells are considered to be parallel, with the same length, and to have the same number of fractures.

Note: This model works with your Harmony Reservoir™ license.

Before you start using the multi-well model, make sure that all required information is added to the Harmony Enterprise project:

- Populate sandface locations for each well in the [Attributes tab](#).
- Populate well production data (rates and sandface pressures) in the [Production editor](#) for each well in the group.
- Specify reservoir and fluid properties in the [Properties editor](#) of the group. When you create a new multi-well model, group reservoir properties are automatically applied.
- Populating wellbore information (such as, a deviation survey, completion, and perforation data) is not required. However, we recommend populating this information because it helps to initiate the multi-well model with correct default settings.

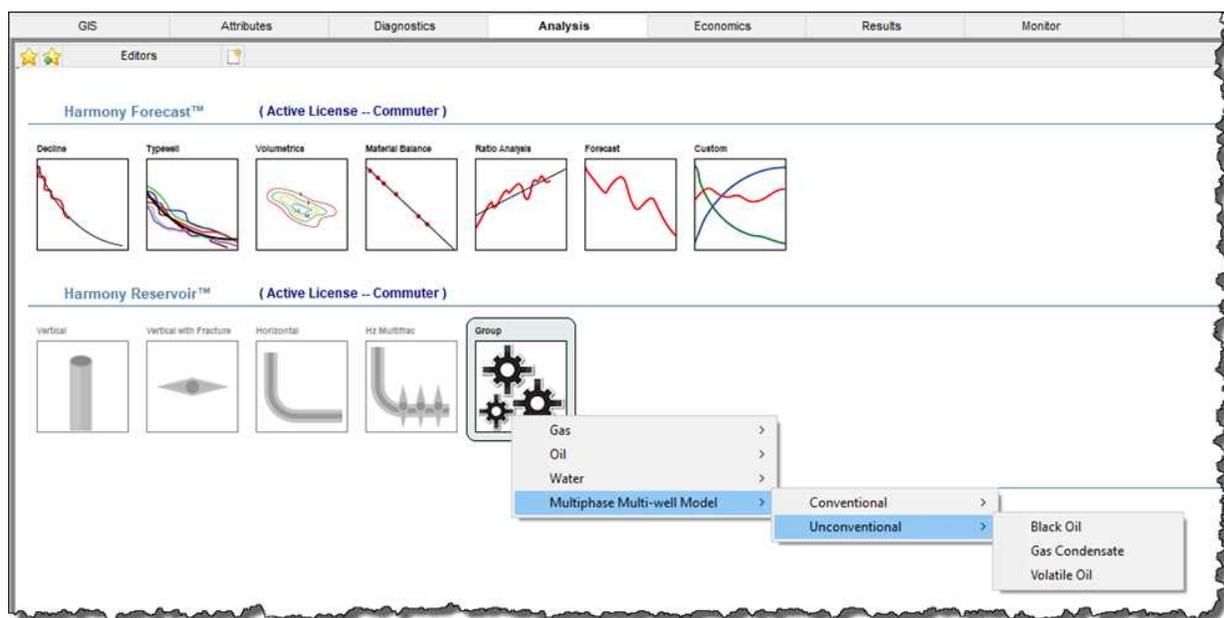
We recommend that you perform analyses and/or modeling for individual wells prior to using the multi-well model. You can bring in parameters from individual well analyses as a starting point for the multi-well model.

By default, the [Plots tab](#) opens (with the Wells button selected) with a dashboard with four plots. For more information, see [dashboard](#).

Model creation

To create an UMW model:

1. Create a group (in the [Entity Viewer - Hierarchy](#) or [Entity Viewer - Custom](#)) that contains all the wells you want to include in the model.
2. Launch the group for analysis. For more information, see [selecting an entity for analysis](#).
3. Click the **Group** image and select **Multiphase Multi-well Model, Unconventional**.



You can create a Black Oil, Volatile Oil, or a Gas Condensate model:

- **Black Oil** — accounts for gas dissolved in liquid, but does not account for liquid vaporized in gas; therefore, you should not create a Black Oil model for a group that has liquid-rich gas as a gas type.
- **Gas Condensate** — used to create a multiphase model that accounts for liquid vaporized in gas. This model should only be used for groups that have liquid-rich gas as their gas type.
- **Volatile Oil** — used to create a multiphase model that accounts for liquid vaporized in gas. The water phase can be turned off within the model.

Note: For more information, see [modifications for the multiphase model](#).

Primary toolbar

The primary toolbar has the following icons:

-  **Pull Defaults** — select from these options:
 - **Group Properties** — copies default values from the [Properties editor](#) of the group.
 - **Group Analysis** — displays a sub-menu with all the other unconventional multi-well models for the group. (If there are no other unconventional multi-well models, this option is not displayed.) Selecting one of the

existing models copies one multi-well model to another in the same group, which can be useful if you want to experiment with the copy of the model while preserving the original content. Note that the parameters on the Forecast tab are not copied.

- **Selected Well Analysis** — displays a sub-menu with all the analyses (that is, URM, analytical, and numerical) for the selected well. (If there are no other analyses, this option is not displayed.) Selecting one of the existing analyses, copies parameters of that analysis to the currently selected well.
- **Another Well in this Model** — displays a sub-menu with all the other wells in the same model. Select one of the wells to copy the calculation method, well parameters, and constraints from that well to the currently selected well (displayed in Wells under Selected Well).
-  **Push Defaults** — copies well parameters from the currently selected well to the one other well you select, or to **All Wells** in the model. Selecting **Model Parameters** copies all parameters set under the Plots Tab \ Wells; selecting **Forecast Parameters** copies parameters set under the Forecast tab for the currently selected well.
-  **Synthesize** — click this icon every time you want to history-match and create a forecast.
-  **Stop Synthesize** — stops the model's synthesize calculations.
-  **Previous Well** — jumps to the previous well.
-  **Next Well** — jumps to the next consecutive well.
-  **Copy to / Paste from Clipboard** — copies / pastes entity parameters from the clipboard.
- Playback icons ()

After you click the **Synthesize** icon () in the primary toolbar and the calculations are complete, the icons listed below are enabled in the same toolbar. With these playback icons, you can see how pressures or saturations change through time. As you hover over your color-shaded plot, a tooltip displays the pressure or saturation value and unit.

-  **Skip to Beginning** — displays the property at time 0.
-  **Step Back One Frame** — view timesteps in reverse one frame at a time.

-  **Play in Reverse** — view timesteps in reverse. You can click this icon multiple times to increase the speed of the playback.
-  **Stop** — stops the playback process. As you hover over various cells in your well, the pressure or saturation is displayed.
-  **Play** — view timesteps from start-to-finish. You can click this icon multiple times to increase the speed of the playback.
-  **Step Forward One Frame** — view one frame at a time.
-  **Skip to End** — displays the last timestep.

Plots tab

This tab displays four plots in a dashboard and has five buttons in the lower left: Wells, Reservoir, Layers, Volumes, and Options. If you do not see all these buttons, click >> and select **Show All Buttons**.

Wells

When you click the **Wells** button, parameters for all wells, the selected well, geometry, permeabilities etc. are displayed.

The screenshot shows a software interface with the following sections:

- All Wells:**
 - L_e : 7314.2 ft
 - n_f : 8
 - x_{wL1} : 500 ft
 - x_{wRn} : 500 ft
 - x_e : 1000.0 ft
 - y_e : 7314.2 ft
- Selected Well:**
 - Well A (dropdown menu)
 - Include
- Geometry:**
 - x_f : 170 ft
 - y_{SRV} : 300 ft
- Permeabilities:**
 - k_{SRV} : 1.0000e-04 md
 - F_{CD} : 50.0
 - $k_f w_f$: 8.5e-01 md.ft
- Advanced Completion Geometry:**
 - x_{fL} : 170 ft
 - x_{fR} : 170 ft
 - x_{SRVL} : 170 ft

Currently, the wells within the UMW model are considered to be parallel, with the same length, and with the same number of fractures. Therefore, the following parameters are shared between all wells:

- L_e — effective horizontal well length. By default, this field is populated based on the perforations that are set up in the Wellbore editor for each well in the group, but you can edit it.
- n_f — number of fractures.
- x_{wL1} — the distance from the first well to the left reservoir boundary.
- x_{wRn} — the distance from the last well to the right reservoir boundary.

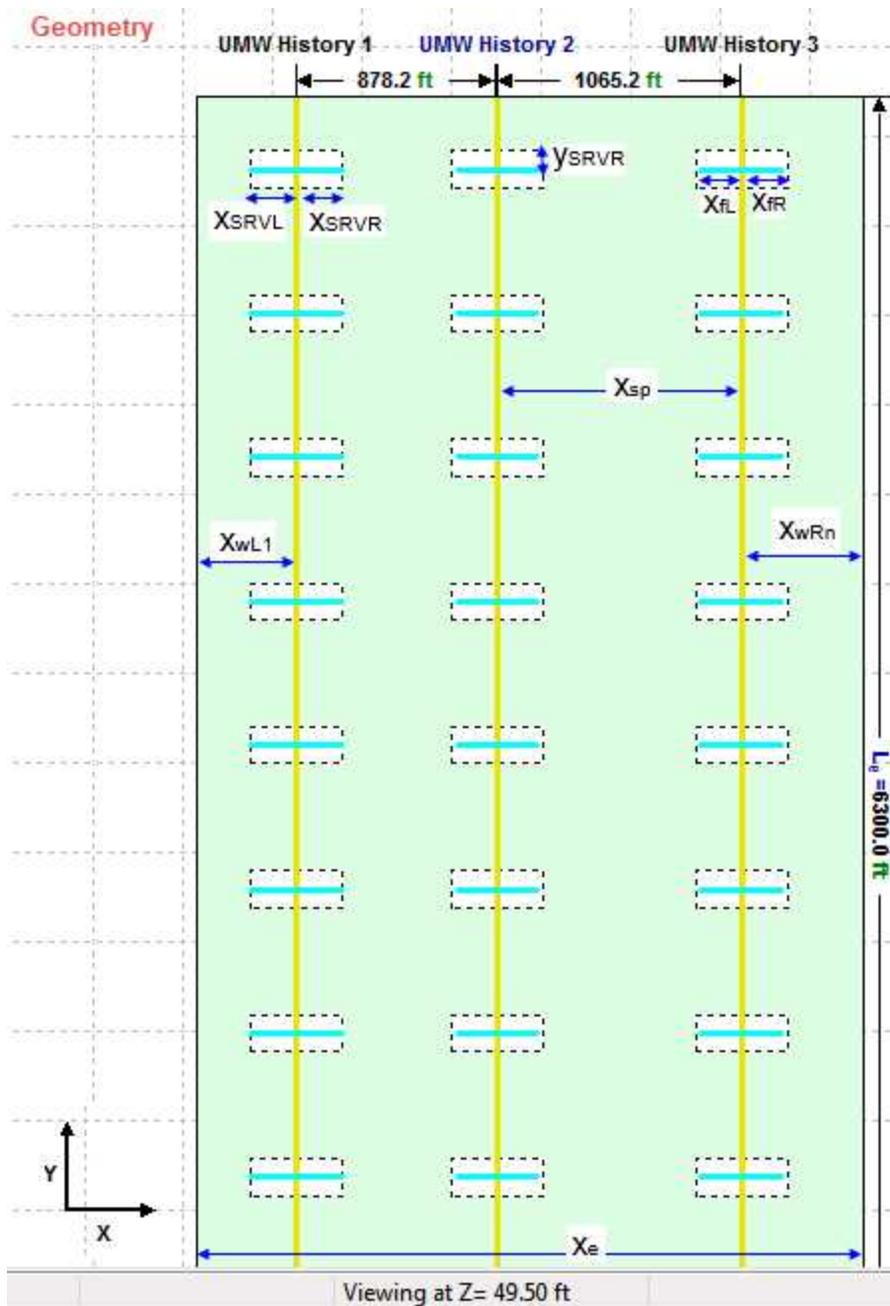
- x_e — extent of the reservoir in the x-direction. This value cannot be edited directly, but can be changed by changing x_{wL1} , x_{wRn} , and x_{sp} for individual wells.
- y_e — extent of the reservoir in the y-direction. By default, $y_e = L_e$.

Note: Setting $y_e > L_e$ makes calculations significantly slower. (In the case when $y_e = L_e$, all fracture stages of the model are identical, and we can make use of the symmetry to increase calculation speed.) If matrix permeability is low, we recommend setting $y_e = L_e$. If matrix permeability is relatively high and contributions from the portions of the matrix that are beyond the wellbore are significant, you can set $y_e > L_e$ to include these contributions. You may also consider running the model with $y_e = L_e$ during the history-matching process, and setting $y_e > L_e$ only to calculate the model's forecast.

The rest of the parameters in Wells are set up on a per-well basis. Select a well from the **Selected Well** drop-down list to set or modify parameters related to that particular well. (You have to set up parameters for each well for the multi-well model to be valid.)

- **Include** — by default, all wells in the group are included in the model. Deselect **Include** to exclude the selected well from the model. If the well is excluded, you still need to set up valid parameters for it: the geometry of the well region is still being used to generate a grid used in the model. However, if the well is excluded, its production is not taken into account, and permeability for the whole well region (including fracture and SRV) is modeled to be equal to the matrix permeability (k_{matrix}).

Geometry



- x_f – fracture half length. Set this field if you want to model a symmetrical fracture with an SRV region extending along the whole fracture. Otherwise, set x_{fL} , x_{fR} , x_{SRVL} , and x_{SRVR} in the Advanced Geometry section.
- y_{SRV} – half SRV in the y-direction.

Permeabilities

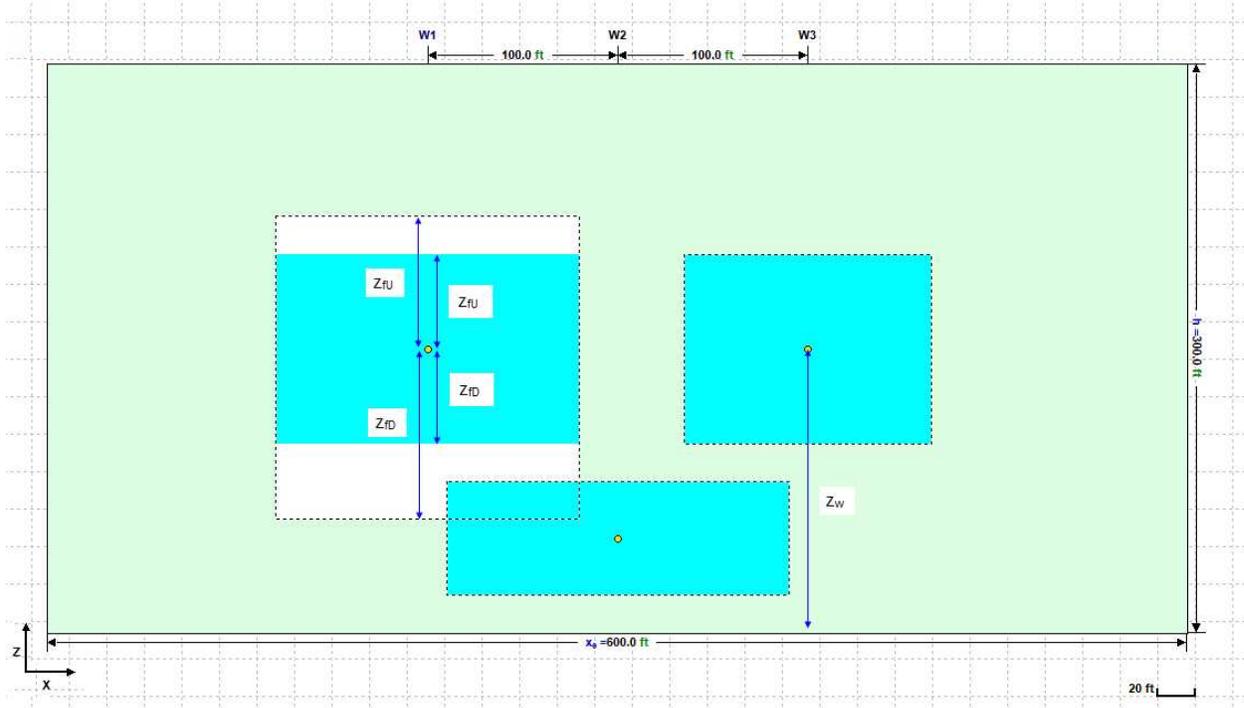
- **k_{SRV}** — SRV (inner zone) permeability.
- **F_{CD}** — dimensionless fracture conductivity.
- **k_fw_f** — fracture conductivity. Fracture conductivity and dimensionless fracture conductivity are related by:
$$F_{CD} = k_f w_f / (k_{SRV} x_f)$$
. You can set any of these two parameters (**F_{CD}** or **k_fw_f**), and the other one is calculated based on the parameter you set.

Advanced Completion Geometry

- **x_{sp}** — the horizontal distance to the next wellbore.
- **x_{fL}, x_{fR}** — use these parameters to set a non-symmetrical fracture. The left wing of the fracture (**x_{fL}**) and the right wing of the fracture (**x_{fR}**) can be different (see geometry above).
- **x_{SRVL}, x_{SRVR}** — use these parameters to set up an SRV that extends less than, or beyond the **x_f** (see geometry above).

Vertical Resolution

Parameters in the Vertical Resolution section are used to set up z-values for well locations and completions. Use this section when wellbores are located at different depths, and when SRV and fractures do *not* extend through the entire thickness of the reservoir. When you set non-default vertical resolution, the model is correspondingly gridded in the vertical direction. In this case, fluid flow is modeled in three dimensions, taking into account k_z/k_{xy} and gravity.



- z_w — vertical distance from the bottom of the reservoir to the wellbore.
- z_{fU} — extent of the fracture (up).
- z_{fD} — extent of the fracture (down).
- z_{SRVU} — extent of SRV (up).
- z_{SRVD} — extent of SRV (down).

Other parameters

- **Calculation Method for Production** — set if the selected well is to be operated at rate, or at pressure control.
- **Calculation Method for Injection** — if you have injection rates for your well in the Production editor, the Calculation Method for Injection section is enabled, and you can set controls to be used during injection.

Reservoir

When you click the **Reservoir** button, you can specify parameters that are used for the entire reservoir model.

Plots		Forecast
Black Oil		
<input checked="" type="checkbox"/>	Gas	
<input checked="" type="checkbox"/>	Oil	
<input checked="" type="checkbox"/>	Water	
Reservoir		
P_i	3000.00	psi(a)
C_r	4.51e-06	1/psi
h	143.0	ft
μ	12.00	%
S_g	10.00	%
S_o	87.00	%
S_w	3.00	%
k_{matrix}	3	md
k_z/k_{xy}	0.100	
<input type="checkbox"/>	Adsorption	
<input type="checkbox"/>	Geomech	

 Wells		
 Reservoir		

If the model has more than one layer, some of the parameters in the Reservoir tab are read-only because they are defined per layer. To set up parameters for each of the layers, click the [Layers](#) button and set parameters there.

k_{matrix} — matrix (outer zone) horizontal permeability within the well region of the selected well.

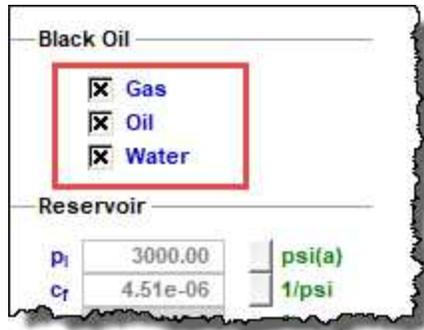
k_z/k_{xy} — the ratio of vertical permeability to horizontal permeability. (This ratio is only being applied to k_{matrix} .)

To include the effect of adsorbed gas, click the **Adsorption** checkbox. Adsorption parameters are set up for the entire reservoir. Note that this option cannot be used for models that include oil or condensate. For more information, see [Langmuir isotherm](#).

To include the effects of changing formation compressibility and permeability with pressure, click the **Geomechanical** checkbox. Geomechanical parameters are set up for the entire reservoir. For more information, see [geomechanical reservoir models](#).

Fluid type selection

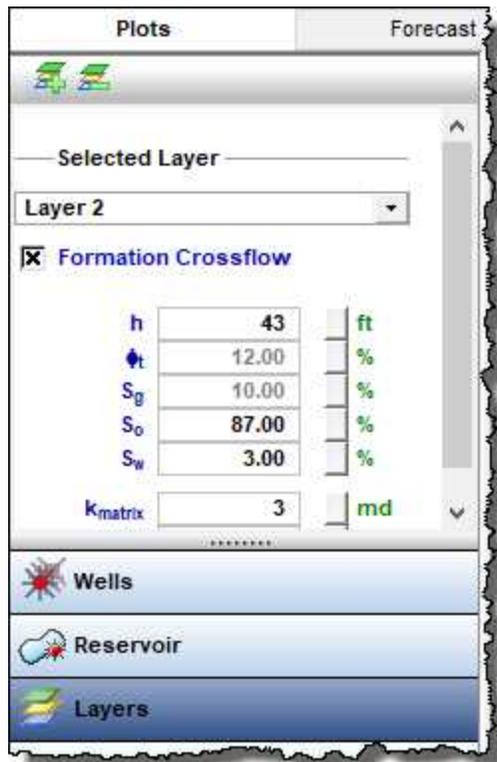
Click the checkboxes for the fluid phases you want to include in your model: **Gas**, **Oil**, and/or **Water**.



The screenshot shows a software interface with two main sections. The top section is titled "Black Oil" and contains three checkboxes, each with a small icon to its left: "Gas", "Oil", and "Water". All three checkboxes are checked, and this entire section is enclosed in a red rectangular box. The bottom section is titled "Reservoir" and contains two input fields. The first field is labeled "p_i" and has the value "3000.00" next to it, with a unit selector set to "psi(a)". The second field is labeled "C_r" and has the value "4.51e-06" next to it, with a unit selector set to "1/psi".

Layers

When you click the **Layers** button, layers for the reservoir are displayed. If your model has only one layer, layer parameters are read-only because the layer is the same for the entire reservoir. Therefore, click the **Reservoir** button and set parameters there.



Toolbar

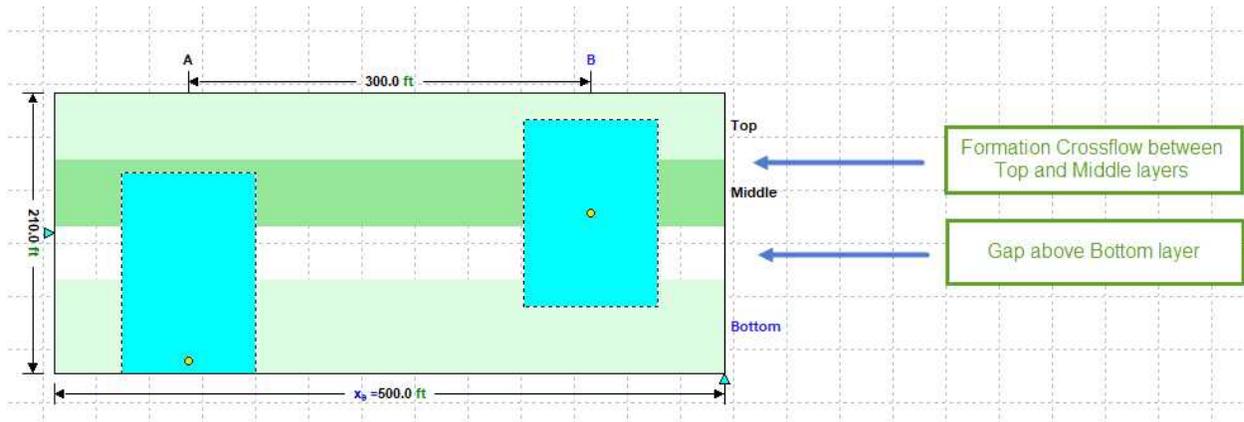
The Layers toolbar has the following icons:

-  **Add New Layer Below the Selected Layer** — opens the Add Layer dialog box where you type a name for the new layer to be added below your currently selected layer.
-  **Remove Selected Layer** — deletes your currently selected layer. You are not prompted to confirm your decision.

To rename a layer, right-click it.

Selected Layer section

To view or modify parameters of a particular layer, select the layer from the **Selected Layer** drop-down list. All of the parameters displayed below are for the selected layer.



Formation Crossflow — this option is available for all layers except for the top one. This option is used to define whether there is communication between the layers through the matrix (formation crossflow), or if the layers are separated by an impermeable layer (gap), and are only communicating through a fracture or SRV.

- If this checkbox is selected, this implies that there is communication between the layers in the reservoir through the matrix.
- If the checkbox is deselected, you can model a gap between the currently selected layer and the one above it; type the height of the gap in the **Gap Above** field. You can view the gap in the XZ view (side view) of the schematic.

Volumes

When you click the **Volumes** button, read-only values for Reservoir, Well, and Layer are displayed. You can switch which Well and/or Layer is displayed by selecting from the drop-down list.

Plots		Forecast
Reservoir		
OGIP _F	0.000	Bscf
OGIP _S	7.403	Bscf
OGIP	7.403	Bscf
OOIP	17626.7	Mstb
OWIP	5560.4	Mstb
A	422	acres
A _{SRV}	165	acres
Well		
UMW History 2		
OGIP _F	0.000	Bscf
OGIP _S	1.292	Bscf
OGIP	1.292	Bscf
OOIP	3076.3	Mstb
OWIP	970.4	Mstb
OGIP _{SRV}	0.317	Bscf
OOIP _{SRV}	754.7	Mstb
OWIP _{SRV}	238.1	Mstb
A _{SRV}	18	acres
Layer		
Layer 1		
OGIP _F	0.000	Bscf
OGIP _S	7.403	Bscf
OGIP	7.403	Bscf
OOIP	17626.7	Mstb
OWIP	5560.4	Mstb

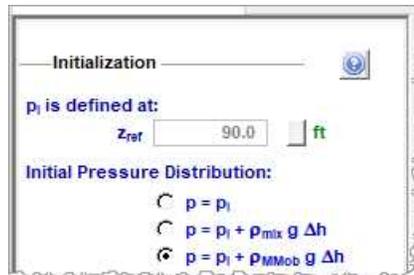
 Wells		
 Reservoir		
 Layers		
 Volumes		

Options

When you click the **Options** button, initialization and gridding parameters are displayed.

Initialization

Initialization parameters are displayed only when the model has more than one grid in a vertical direction (for example, when the model has multiple layers).



- **z_{ref}** — this is the distance from the bottom of the reservoir to the reference depth for p_i . Initial pressure for the reservoir (p_i) is defined in Reservoir. By default, it is assumed that the value of the initial pressure corresponds to the middle of the reservoir's pay. However, you can change the reference depth at which p_i is defined. For example, if you set $z_{ref} = 0$ ft and $p_i = 5000$ psi(a), it means that initial pressure *at the bottom of the reservoir* is equal to 5000 psi (a).

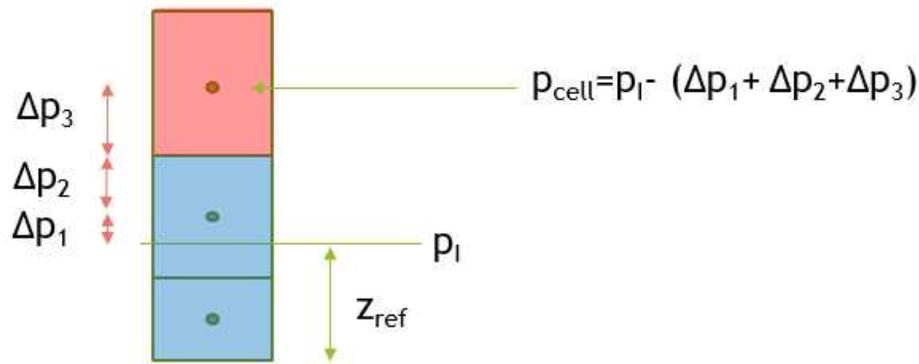
After the initial pressure is set at the reference depth, initial pressure at each of the model's grid cells is calculated according to the options set under Initial Pressure Distribution:

- **$p = p_i$** — the initial pressure in each cell is equal to p_i .
- **$p = p_i + \rho_{mix} g \Delta h$** — the pressure in each cell is calculated as described in the figure below. Each individual pressure difference is calculated as: $\Delta p = \rho_{mix} g \Delta h$, where ρ_{mix} is the mixture density and is calculated as:

$$\rho_{mix} = \frac{S_{gi} \cdot \rho_g + S_{oi} \cdot \rho_o + S_{wi} \cdot \rho_w}{S_{gi} + S_{oi} + S_{wi}}$$

where only mobile phases are included in both summations.

- **$p = p_i + \rho_{MMob} g \Delta h$** — the pressure in each cell is calculated as described in the figure below. Each individual pressure difference is calculated as $\Delta p = \rho_{MMob} g \Delta h$, where ρ_{MMob} is the density of the most mobile phase in the cell.

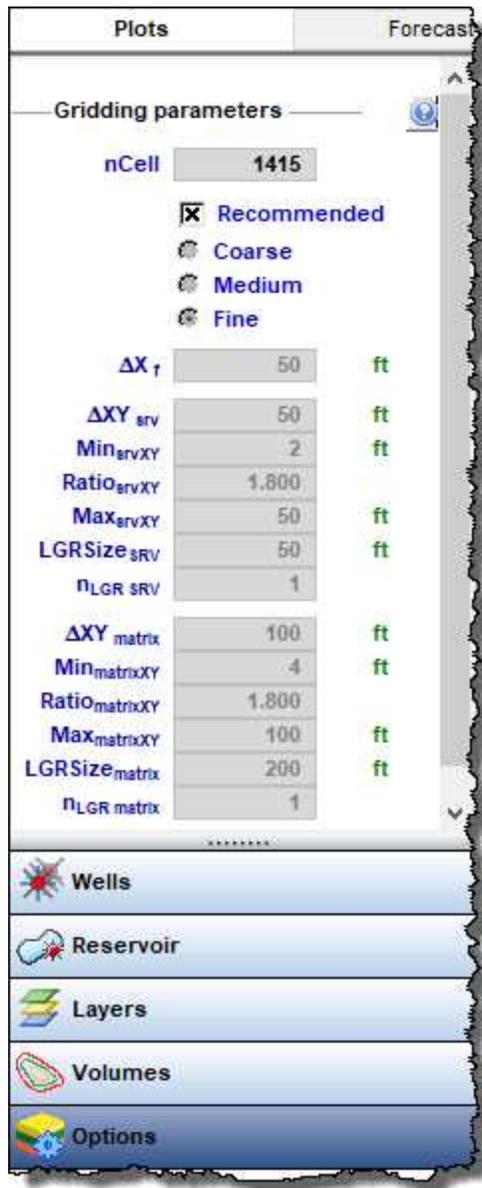


We recommend setting up the model such that the phases are segregated (that is, each cell has only one mobile phase, with lighter phases above). In this case, the second and third options reduce to: $\Delta p = \rho g \Delta h$, where ρ is the density of only the mobile phase in the cell. Selecting either the second or third option results in initializing the system to be in hydrostatic equilibrium. If you decide to set up the model such that the phases are not segregated, the model will not be in equilibrium, no matter what option you select. (The phases start segregating due to gravity as a part of the model's simulation.) Depending on the case, distributing pressures using one of the available options may help to initialize the model to a state that is close to hydrostatic equilibrium.

Gridding Parameters

After you set your reservoir dimensions, well locations, and well completion parameters, the UMW model creates an appropriate grid to get accurate results with minimal calculation time. To display gridding, right-click the schematic plot and select **Show Grid Cells**.

Usually, the default gridding settings work well, but in some cases, you may want to adjust the gridding options by changing gridding parameters.

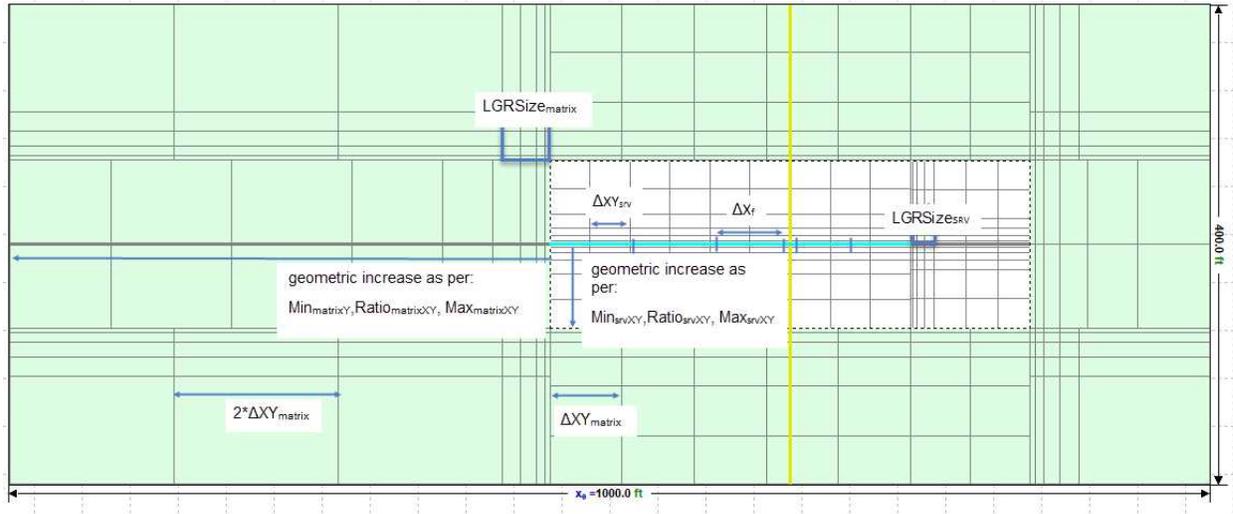


There are three predefined gridding options: Coarse, Medium, and Fine. When the **Recommended** option is enabled, one of the pre-defined options is automatically selected based on model parameters.

Alternatively, you can deselect **Recommended** and set your gridding manually. For example, you may want to use **Coarse** gridding while history-matching the model, and then switch to **Fine** gridding after the match is done.

If you need even more flexibility, you can select the **Custom** option and edit each gridding parameter individually. If you select this option, refer to the schematic of a model's grid and description of individual gridding parameters below:

- The fracture has a cell containing the wellbore and its size is fixed. The rest of the fracture is divided into equal cells with an x-dimension approximately given by ΔX_f .
- The SRV regions have arithmetic gridding in the x-dimension (approximately given by ΔXY_{SRV}) and geometric gridding in the y-dimension (given by Min_{SRVXY} , $Ratio_{SRVXY}$, and Max_{SRVXY}).
- The matrix is split into a number of partitions (defined by the locations and SRV-boundaries of all the wells), and then each partition is gridded individually.
Partitions that have SRV regions adjacent to them have geometric gridding starting at the boundary with the SRV region. This is done to capture large pressure gradients in such areas. (Geometric gridding is governed by $Min_{matrixXY}$, $Ratio_{matrixXY}$ and $Max_{matrixXY}$.)
In other cases, matrix partitions have arithmetic gridding (the size of the cells are approximately equal to the ΔXY_{matrix} for the partitions that are adjacent to SRV regions, and are approximately equal to $2 * \Delta XY_{matrix}$ for other matrix partitions.)
- Local grid refinements (LGRs) are added for those corners of matrix partitions that are touching SRV corners. The size of the local grid refinement is defined by $LGRSize_{matrix}$. The refined grid within those LGR areas is built by continuing grid lines from the adjusting partitions (that are gridded geometrically). Every $n_{LGR\ matrix} - th$ line is being continued.
- Local grid refinements are also added for the portions of the SRV that are touching fracture tips. The size of the LGR is defined by $LGRSize_{SRV}$. The refined grid within those LGR areas is built by continuing grid lines from the adjusting partitions (that are gridded geometrically). Every $n_{LGR\ SRV} - th$ line is being continued.



Dashboard

In the dashboard, there are four plots.

You can switch which plots (that is, XY Schematic, Ratios, Well Rate Time, Total Rate Time, XZ Schematic, and YZ Schematic) are displayed in the dashboard by clicking the **Change Plot** button in each plot's toolbar.

Note: If you maximize a plot in the dashboard, you are not able to switch the plot until you minimize its view. For a description of common icons, see [plot toolbars](#).

Ratios plot

This plot displays historical and simulated ratios for the selected well.

Well Rate Time plot

This plot displays historical and simulated rates and pressure for a single well. To show or hide gas / oil / water, click the appropriate icon(s): .

Be aware that you can switch views with this icon:

 **Switch to Rate vs Time / Switch to Cumulative vs Time** — toggle between these two views.

To switch wells, you can:

- Click the arrows in the main toolbar.
- Select a different well from the **Select Well** drop-down list.

Total Rate / Cum Time plot

This plot displays the total historical and simulated rates / cumulative production for the entire reservoir, and the reservoir pressure. To show or hide gas / oil / water, click the appropriate icon (s):  .

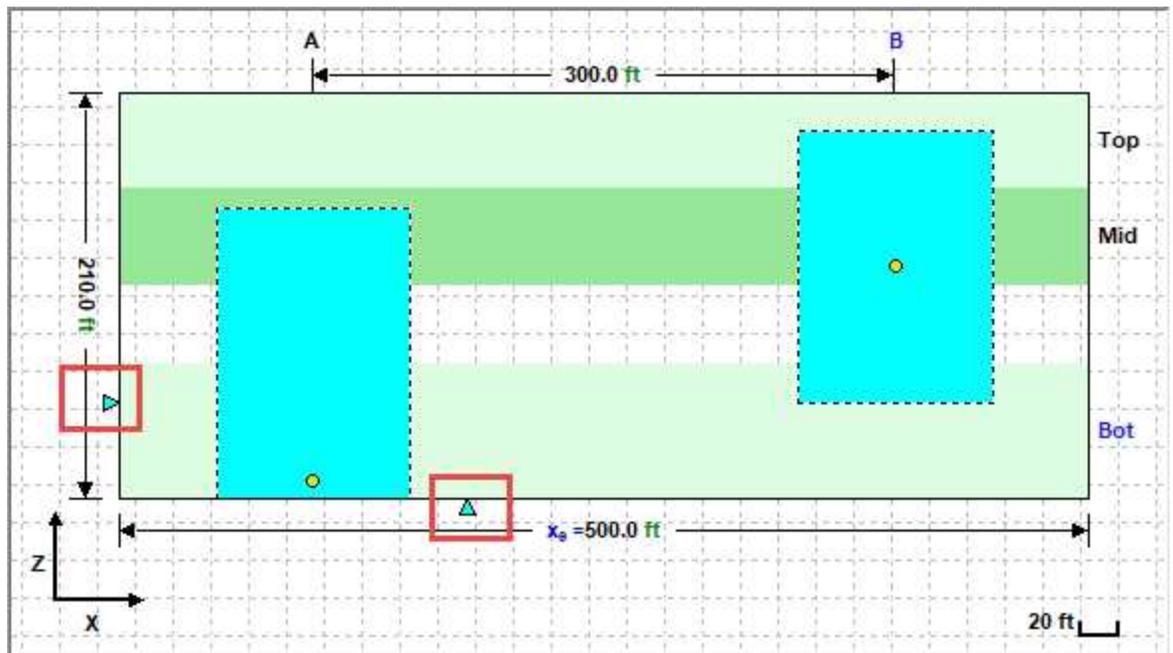
Be aware that you can switch views with this icon:

 **Switch to Rate vs Time / Switch to Cumulative vs Time** — toggle between these two views.

Schematic plot

This plot displays a schematic view of the reservoir shape, and the location of the wells within it. After you run the model, you can use the same plot to view distribution of cell properties (pressure, saturation of any phase or permeabilities) at any timestep.

You can have schematic plots displaying XY, XZ, or YZ cross-sections. If more than one cross-section is displayed, each cross-section has blue arrow tips indicating the location of the other cross-sections.



These toolbar icons are unique to this plot:

Pressure ▾

Shaded plot display mode — this drop-down list becomes available after the model has been synthesized. Use this drop-down list to select which property you want to display in each grid cell. You can select one of the following properties to display it: Pressure, Saturations (color scheme based on saturations of all three phases), Gas Saturation, Oil Saturation, Water Saturation, or Permeability.

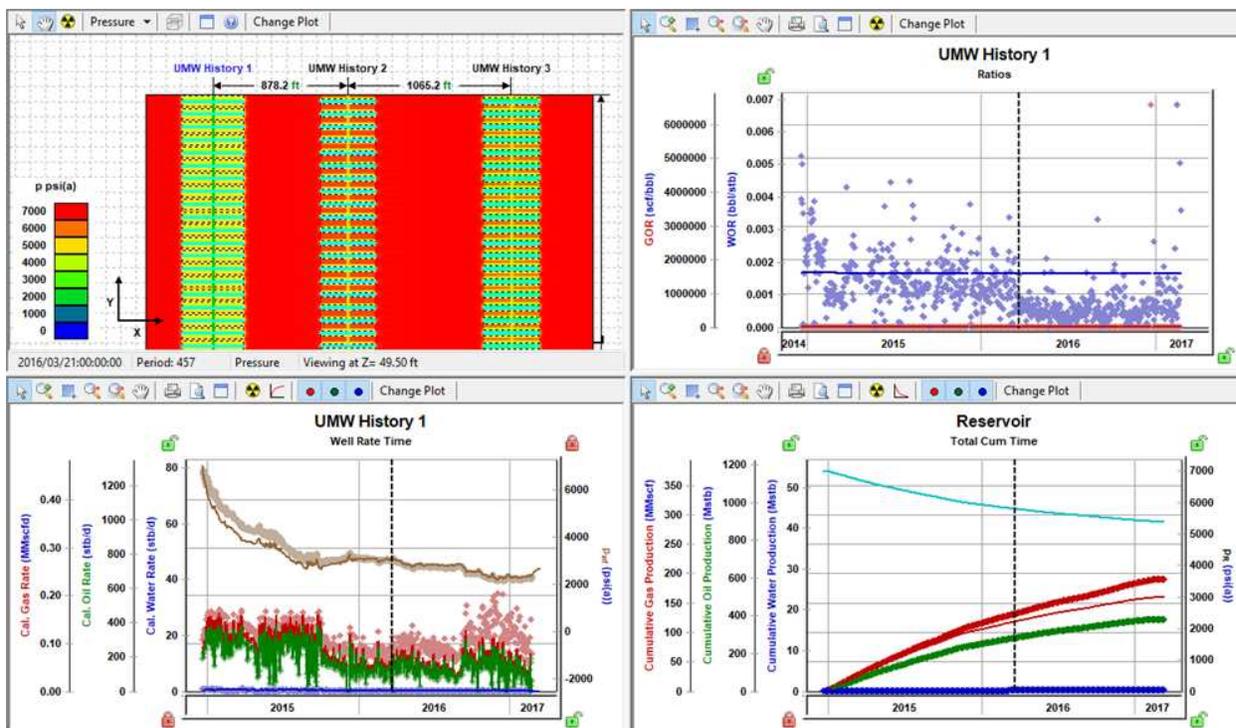


Set Cross Section Location — by default, all XY Schematics have a cross-section drawn through the middle of the pay. However, you can set the cross-section to be drawn at any given distance, Z, from the bottom of the reservoir. (Similarly, you can set the desired locations for cross-sections for ZX and YX Schematics.)

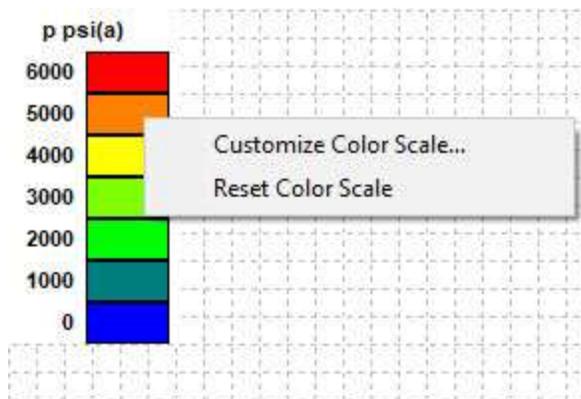
For information on common plot icons, see [plot toolbars](#).

After you click the **Synthesize** icon () in the primary toolbar, the synthesis proceeds. Lines representing simulation results are drawn as the simulation progresses.

Position lines indicate calculation progress. The shaded plot displays the distribution of pressure or saturation at the timestep that has just been calculated (as indicated by the time-stamp in the lower left corner, which displays the exact date and time). After the calculation is completed, these Position lines can be dragged to the moment in time you want to examine more closely, and all plots are synchronized.



If you find that the color scale for your shaded plot needs adjusting, right-click the legend and select **Customize Color Scale**, and then enter customized min and max values. To revert back to the default min and max values, right-click the legend and select **Reset Color Scale**.



Context menu

Right-clicking the reservoir view for your wells lists these options:

- **Show Grid Cells** — displays a grid layout on your schematic.
- **Show Shaded Plot** (after Synthesizing) — displays the plot after the synthesis process is completed.
- **Show Scale Gridlines** — show / hide gridlines with a scale marker.
- **Show Dimensions** — show / hide dimensions on the right-side of the plot.
- **Show Cross-section Locations** — show / hide cross-sections.
- **Show Layers** — show / hide layers. This option is displayed, if more than one layer exists.
- **Different Colors for SRV and matrix** — when this option is selected, the SRV and matrix are displayed in a different color from the rest of the schematic. When this option is deselected, the entire schematic is displayed in white.
- **Show Single Fracture Schematic** — displays a close-up view of the fracture. You can toggle back to Show Entire Model Schematic.

Forecast tab

This tab has the same features as the numerical Forecast sub-tab, but you have the option to display all wells in the group, or individual wells.

Forecast Plot

If **All Wells** is selected in the Select Well drop-down list, the Forecast plot displays group-level rates and reservoir pressures. If one of the wells is selected in the Select Well drop-down list, the Forecast plot displays rates and flowing pressures for that selected well.

Forecast Options

Use the Select Well drop-down list to pick any individual well or All Wells. Select one of the wells to see forecast settings for just that well in the Forecast table, or select **All Wells** to see forecast settings for all the wells together.

The Forecast Start Date is set for the entire model (the forecast for *all* the wells starts at this given date).

The values in the Duration column are shared between all the wells in the model.

Forecast Constraints are applied for all of the wells in the model.

After you set up a valid forecast and synthesize it, the Forecast Results table displays EUR, RR, RF, and historical volumes for each well for each of the fluid phases available in the model.

Forecast injection

To forecast injection for any well, select one of these options from **Control Type** drop-down list:

- **Gas Inj Rate** — the forecast at a given gas injection rate.
- **Water Inj Rate** — the forecast at a given water injection rate.
- **Pressure (Inj Gas)** — the forecast at a given sandface flowing pressure. (This pressure is reached by injecting gas.)
- **Pressure (Inj Water)** — the forecast at a given sandface flowing pressure. (This pressure is reached by injecting water.)

Note: In order for the above options to be available, the corresponding fluid phase must be selected when you click the **Reservoir** button.

Injection constraints are applicable when at least one of the wells has an injection forecast.

- $(p_{inj})_{max}$ — sets a maximum sandface flowing pressure during the forecast. In order to maintain the maximum flowing pressure, the injection rate is adjusted.
- $(q_{ginj})_{max}$ — sets a maximum gas injection rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted.

- $(q_{winj})_{max}$ — sets a maximum water injection rate during the forecast. In order to maintain the maximum rate constraint, flowing pressure is adjusted.

Toolbar

This toolbar has the same common icons described in [plot toolbars](#).

Tables tab

This tab displays calculation results in a tabular format.

Numerical model

The numerical model has been modified from Harmony to significantly reduce computation time, so that it is almost as fast as an analytical model. For more information, see [numerical model theory](#).

Note: This analysis works with your Harmony Reservoir™ license.

Before you start using the numerical model, make sure that all required information is added to the Harmony Enterprise project. Well production data (rates and sandface pressures) should be populated in the [Production editor](#), and reservoir and fluid properties should be specified in the [Properties editor](#). When you create a new numerical model, reservoir properties are automatically applied.

We recommend that you perform an analysis prior to using the numerical model as a starting point for other model parameters. For example, for conventional wells, a flowing material balance (FMB) gives an estimate for original fluid in-place, and the use of a [typecurve](#) analysis provides insight about permeability, skin, reservoir shape / size, and fracture properties. For unconventional wells, an [unconventional reservoir analysis](#) can be used to estimate permeability, fracture length, apparent conductivity, and the size of the stimulated reservoir volume.

You can [history match](#) your data using two methods (automatic parameter estimation (APE) and synthesize), but there are important differences.

APE — you can select one or more parameters, and the numerical model keeps the other parameters constant while the parameters being varied are adjusted to reduce the average error between the production history and the model's results.

Synthesize — does not change parameters, but rather all historical data and the parameters in the table are used to run the model. The "match" is what is displayed after the model has been

run.

For more information, see the [primary toolbar](#) where both of these icons are described.

Numerical Model pane

In the Numerical Model pane, enter the required parameters, and select your calculation method. You can use the rates of any of the fluids displayed in the model to calculate rates for the remaining fluids, and the sandface flowing pressure. Or, you can use the sandface flowing pressure to calculate rates for all the fluids displayed in the model.

The screenshot shows the 'Numerical Model' dialog box with the following parameters and values:

A_{sRV}	39	acres
OGIP _F		MMscf
OGIP _A	1431.467	MMscf
OOIP	1945.9	Mstb
OWIP	1114.7	Mstb
OGIP _{sRV}	668	MMscf
OOIP _{sRV}	908.1	Mstb
OWIP _{sRV}	520.2	Mstb
r_w	0.350	ft

Below these fields is a checkbox for 'Chg. Skin' which is unchecked. The 'Calculation Method:' section is highlighted with a red box and contains the following options:

- Use Gas Rate
- Use Oil Rate
- Use Water Rate
- Use Pressure

Under 'Use Pressure', there is a pressure input field with the value 14.7 and units psi(a). Below this are three more input fields for $q_g \leq$, $q_o \leq$, and $q_w \leq$ with units MMscf, bbl/d, and bbl/d respectively.

For information on the numerical model's options, see [advanced options](#).

Important parameter limits

Note that these parameter limits apply:

- $k_x, k_y > 0$
- skin: $-8 \leq s < 200$
- s_{lim} (located within the Chg Skin section): $-8 \leq s_{lim} < 200$

- $\text{MinXY} / 2 < X_w < X_e - \text{MinXY} / 2$
- $\text{MinXY} / 2 < Y_w < Y_e - \text{MinXY} / 2$

Fluid type selection

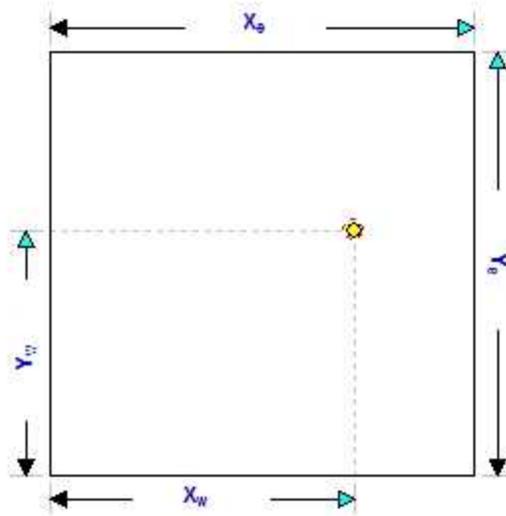
With numerical worksheets, you can select these fluid types based on the fluid behavior you want to simulate:

- **Gas + Immobile Water** — used to create a single-phase model. Only gas flow is modeled in this case; water is considered immobile. If you create a Gas+Immobile Water numerical model for a liquid-rich gas well, the model is calculated in terms of recombined gas (see [recombination](#)).
- **Black Oil** — accounts for gas dissolved in liquid, but does not account for liquid vaporized in gas; therefore, you should not create a Black Oil model for liquid-rich gas wells. Oil and water phases can be turned off within the model.
- **Gas Condensate** — used to create a multiphase model that accounts for liquid vaporized in gas. This model should only be used for liquid-rich gas wells. Condensate and water phases can be turned off within the model.
- **Volatile Oil** — used to create a multiphase model that accounts for liquid vaporized in gas. The water phase can be turned off within the model.

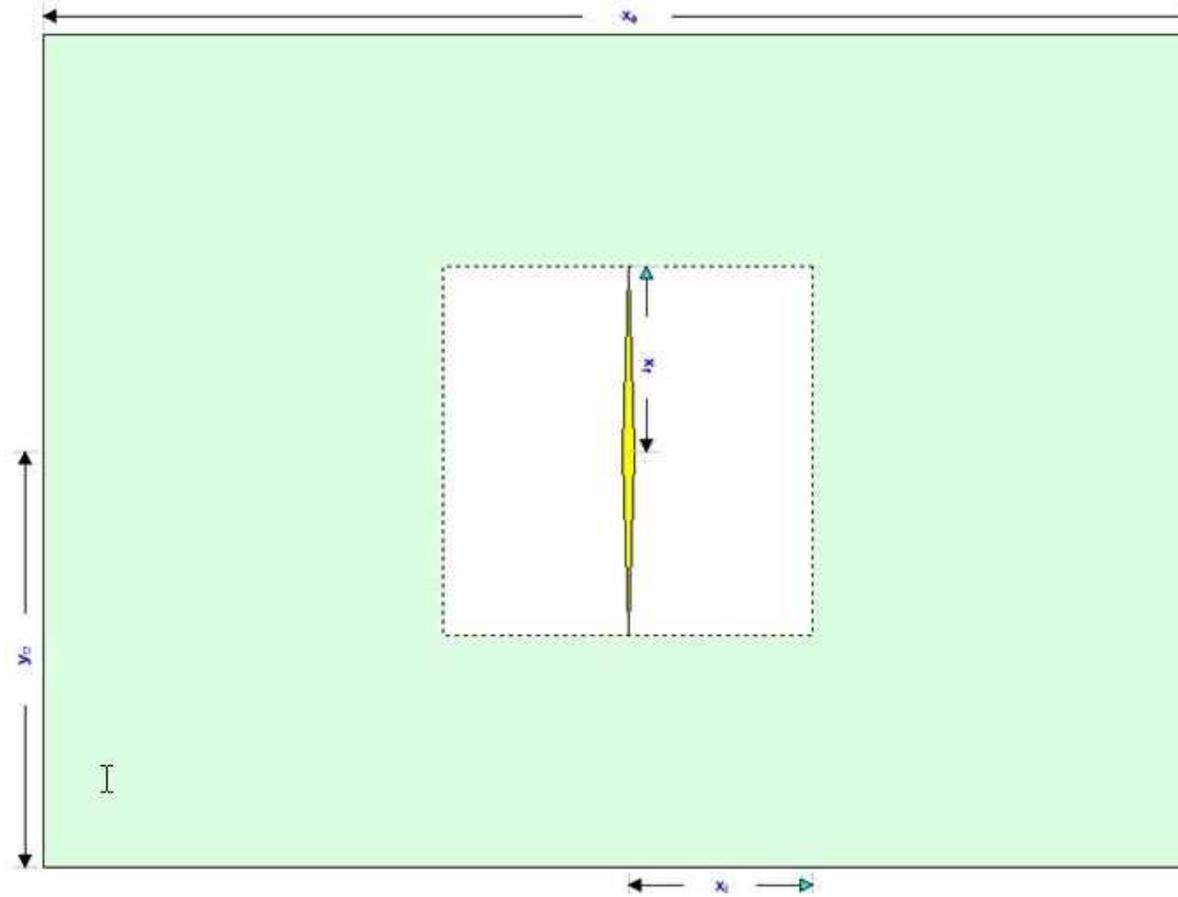
Model geometry

Harmony Enterprise supports the following:

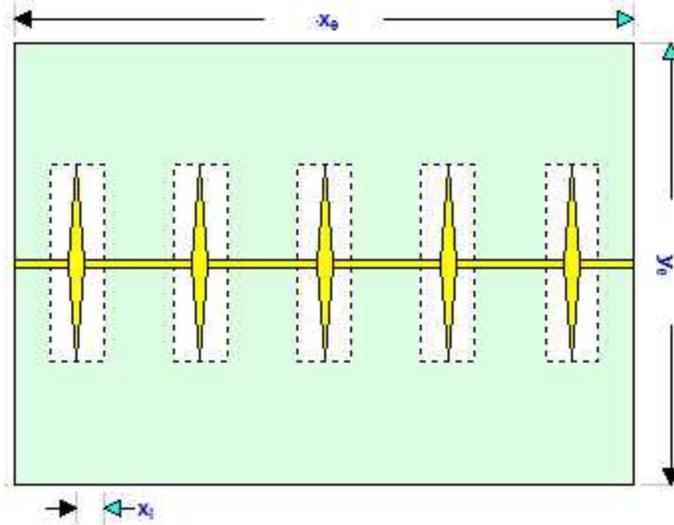
- **Vertical** — this model contains a vertical well located anywhere within a rectangular-shaped homogeneous reservoir.



- **Vertical with Fracture** — this model contains a hydraulically fractured vertical well located in the center of a rectangular reservoir. The fracture is surrounded by a symmetrical region of higher permeability.



- **Horizontal Multifrac** — this model enables you to specify an enhanced permeability in a region around each fracture. It contains an inactive horizontal well fed by multiple identical, and equally spaced, transverse fractures. The length of the reservoir is defined by the horizontal well. The extent of the enhanced region in the y-direction is defined by the fracture length.



Primary toolbar

There are three toolbars: primary, Plots sub-tab, and Forecast sub-tab.

The primary toolbar has the following icons:

- 
Defaults — copies parameters from the Properties editor or other Reservoir worksheets. If you have any analytical gas horizontal multifrac model created for the same well, we recommend that you use it to populate the numerical model's parameters.

Or, if you want to copy only one parameter from an analysis, click the **View Defaults and Limits** button to the right of the field in the Numerical Model pane.

Note: Parameters copied from the reservoir or another analysis are displayed in a gray font. This indicates that they match the default. You can type new values for any parameter, or change values for some parameters by moving elements of the schematic. Parameters, which do not match the default, will be shown in a black font.

- 
Automatic Parameter Estimation (APE) — while APE is running, selected parameters are automatically varied to minimize the error between the simulated pressure / rate and the actual pressure / rate depending on the calculation method (rate or pressure calculation method — for additional information, see the numerical model pane). The updated simulated pressure / rate is shown on the plots while the calculation is running. While APE is running, the icon appears selected. To stop APE, click the icon again and it no

longer appears selected. The model remains at the last parameter set and the history matching finishes calculating for the model. For more information, see [using APE](#) (same functionality as with the analytical worksheet).

Important: The purpose of history matching is to get the calculated pressures to reproduce actual pressures as closely as possible by changing the model's parameters. You can vary model parameters manually, or use APE.

-  **AutoCalc** — recalculates the history match and forecast automatically each time you change model parameters.
-  **Synthesize** — if you do not click the AutoCalc icon, you must click this icon every time you want to recalculate the model.
-  **Stop Synthesize** — stops the model's synthesize calculations.
-  **Use Sparse Production Data** — opens the Use Sparse Production Data dialog box where you specify the number of timesteps for simulation. This enables you to run simulations with a smaller number of timesteps in order to speed up calculation times. For more information, see [sparse data](#).

You can switch which plots are displayed in the dashboard by clicking the Add an available view icons (to the far right of the other icons on the primary toolbar).

-  — select a plot to be displayed in the top right corner of your dashboard.
-  — select a plot to be displayed in the lower right corner of your dashboard.

Sub-tabs

There are three sub-tabs: Plots, Forecast, and Tables.

Plots

This sub-tab displays a schematic and plot from your well data.

Toolbar

This toolbar has the following important icons:

-  **Reset Plot Attributes** — resets your plot attributes to default settings.
-  **Picture in Picture** — opens the Zoomed View popup where you can get a closeup view of your datasets.
-  **Weight Data Points** — used to emphasize matching to specific data points when using APE (for example, the last part of the production). The cursor changes to a spray gun when clicked. Weighted data points are displayed in a brighter color and are given a 100% weighting; unweighted points are given a 10% weighting. (The weighting is displayed when you hover over the data point.)
-  **Copy** — copies plot data.
-  **Hide the Toolbar** — hides the toolbar. If you want the toolbar displayed, right-click the plot and select **Show Toolbar**.

After you click the **Synthesize** icon () in the primary toolbar and the calculations are complete, the icons listed below are enabled in your color-shading plots (vertical, vertical fracture, horizontal, horizontal multifrac). With these playback icons, you can see how pressures or saturations change through time. A schematic for your color-shading plot is displayed as long as you specify reservoir dimensions, and the schematic is updated as you change reservoir parameters (for example, X_e , Y_e). A tooltip displays your value and unit, as well as your cursor's x- and y-position within the model as you hover over your color-shading plot.

-  **Skip to Beginning** — resets the display to how things were prior to clicking the Synthesize icon.
-  **Step Back One Frame** — view calculations in reverse one frame at a time.
-  **Play in Reverse** — view calculations in reverse. You can click this icon multiple times to increase the speed of the playback.
-  **Stop** — stops the playback process.
-  **Play** — view calculations from start-to-finish. You can click this icon multiple times to increase the speed of the playback.
-  **Step Forward One Frame** — view calculations one frame at a time.
-  **Skip to End** — shows the last calculation.

For information on common plot icons, see [plot toolbars](#).

As the numerical model is calculating results, the color-shading plots update every 100 ms. These intervals are maintained in the steps that are available to play as an animation. When a model calculates very quickly, fewer steps are available, resulting in large jumps for the timesteps displayed.

Forecast

This sub-tab has a toolbar, and displays your forecast: options, constraints, and results.

After the model has been populated and calibrated to the production and pressure data through history matching, production forecasts can be created and compared under a variety of different constraints. This can also be used to create a production forecast for wells with no production history.

Toolbar

This toolbar has the same common icons described in [plot toolbars](#).

Forecast options

The Forecast Options section is where forecast periods are defined according to either durations (for example, months), or dates.

- Setting the forecast time method to **Duration** begins a forecast at a specified start date. Forecast periods are then defined in the forecast table according to a length of time (the default is months). For each forecast period, different operating conditions can be specified.
- Setting the forecast time method to **Start Date** creates a forecast of a specified length of time (the default is months). Forecast periods are then defined in the forecast table according to calendar dates.



If you select **Duration** from the Forecast Time Method drop-down menu, the Start Date is automatically populated. (You can change this date later, if needed.)

The screenshot shows a 'Forecast Parameters' dialog box. Under 'Forecast Options', the 'Forecast Time Method' is set to 'Duration'. Below it, the 'Start Date' is populated with '27/09/2012', which is circled in red. To the right of the date field is a green label 'DD/MM/YYYY'.

If you select **Start Date** from the Forecast Time Method drop-down menu, enter a value for Duration (that is, the total length of the forecast).

The screenshot shows the 'Forecast Parameters' dialog box. Under 'Forecast Options', the 'Forecast Time Method' is set to 'Start Date'. Below it, the 'Duration' is set to '120.0 month', with '120.0' circled in red. A green label 'month' is positioned to the right of the duration field.

Further details about each forecast period are entered in the forecast options table.

	Time			Control		Sandface Pressure	
	Step Type	Duration	# of Steps	Interpolation Method	Control Type	Initial	Final
		month				psi(a)	psi(a)
1	Arithmetic	Required	Required	Step	Pressure	1626.85	

Each row of the table above represents a forecast period. An additional forecast period can be added each time an operational change is encountered (for example, the flowing pressure decreases when a compressor is added). To add a row, use the down arrow when the cursor is in a cell of the last existing row.

The forecast options table has the following sections:

- **Time** — defines the length of each forecast period and each timestep, and has the following columns:

- **Step Type** — sets the spacing of the timesteps, and can be set to either Arithmetic or Logarithmic. The Arithmetic step type spaces the number of timesteps equally over the total duration of the period, whereas the Logarithmic step type spaces the number of timesteps logarithmically (that is, increased density near the beginning of the forecast).
 - **Forecast Time Method (Duration / Start Date)** — sets the length of the forecast period. If the Forecast Time Method is set to Duration, this column shows Duration. If the Forecast Time Method is set to Start Date, this column show Start Date.
 - **# of Steps** — sets the number of timesteps in the forecast period.
- **Control** — defines how the operating conditions change over the forecast period, and has the following columns:
 - **Interpolation** — can be set to either Step or Ramp. "Step" keeps the control type constant over the forecast period. "Ramp" varies the control type linearly from an initial value to a final value.
 - **Control Type** — sets what is used to calculate the forecast. For the numerical model, the forecast can be run using either flowing pressure, or one of the rates being analyzed.
 - **Sandface Pressure** — if the Control Type is set to Pressure, this column is displayed, and it is used to set the flowing pressure for the forecast period. If Interpolation is set to Step, only the initial pressure cell is editable. If Interpolation is set to Ramp, initial pressure and final pressure are selectable.
 - **<Fluid> Rate** — if the Control Type is set to a <Fluid> Rate, this column is displayed, and it is used to set the rate for the forecast period. If Interpolation is set to Step, only the initial rate's cell is editable. If Interpolation is set to Ramp, initial rate and final rate are editable.

Forecast constraints

The Forecast Constraints section is where maximum rate conditions and abandonment rate conditions for the forecast can be entered. Available constraints include the following:

- p_{\min} — the minimum allowable sandface flowing pressure during the forecast. In order to ensure flowing pressure does not go below this value, rates are adjusted.
- $(q_g)_{\max}$ — sets a maximum fluid rate during the forecast. In order to maintain the maximum fluid rate constraint, flowing pressure is adjusted.

- $(q_g)_{ab}$ — sets the abandonment fluid rate for the forecast. When the abandonment rate is reached, the forecast ends.

Forecast results

The Forecast Results section is where the results of the forecast are summarized. Available results depend on the analysis type, and could include the following:

- EUR — expected ultimate recovery.

Note: For wells with historical data, EUR is defined as the cumulative of the historical data up to the beginning of the forecast, after which time, the synthetic cumulative calculated from the model is used until the end of the forecast.

- RR — remaining recoverable.
- RF — recovery factor.

Tables

The sub-tab displays your history match (after you use the [synthesize](#) or [APE](#) functionality) and forecast data (after you populate all the required values in the Forecast tab) in a tabular format.

Note: The single-phase model ([Gas + Immobile Water](#)) is the only model that displays the Blasingame plot on the dashboard. This plot is created using the gas analytical model with identical input parameters. (To generate a Blasingame plot for the [horizontal multifrac numerical model](#), Harmony uses a gas analytical [enhanced frac region](#) model. To generate a Blasingame plot for the vertical numerical model, Harmony Enterprise uses a gas analytical vertical model.)

For more information, see [tables](#).

Forecasting using wellhead pressure

By default, numerical models use sandface pressures for forecasting. When the Control Type is set to Pressure, the model calculates production rates based on sandface flowing pressure.

However, you can also forecast production rates from wellhead flowing pressure. When the Wellhead Flowing Pressure option is selected, and the Control Type is set to Pressure, numerical models calculate production rates based on wellhead flowing pressure.

Note: Wellhead forecasting has not been implemented for wellbore configurations with their Flow Path set to Gas Lift or Pumping.

After you have defined your wellbore in the Wellbore editor, and created a valid numerical model, click the **Forecast** tab and make sure that **Wellhead** is selected from the Forecast Flowing Pressure drop-down list.



For the Control Type:

- If Pressure is selected, enter the wellhead flowing pressure.
- If Rate is selected, both sandface and wellhead flowing pressures are calculated during the forecast; however, only sandface flowing pressures are displayed on the Results plot. Both the sandface (p_{wf}^{calc}) and wellhead flowing pressures (p_{tf}^{calc}) are displayed in the Tables tab.

In most cases, numerical models calculate a combination of gas, oil and/or water rates. Therefore, pressures are calculated based on multiphase flow rates.

Note: Combining multiphase flow calculations in both the wellbore and the model results in a significant amount of uncertainty. Performing a wellhead forecast twice in a row may generate different results due to the possibility of multiple valid solutions.

Advanced numerical model options

Advanced numerical model options include:

- Adsorption
- Geomechanical
- Refracturing
- Changing skin

- [Sparse data](#)
- [Adjusting gridding](#)

Note: Automatic parameter estimation (APE) works the same way as with the analytical analysis. For more information, see [using APE](#).

Adsorption option

To include the effect of adsorbed gas, click the **Adsorption** checkbox in the Analytical Model or Numerical Model pane. Note that this option cannot be used for models that include oil or condensate.

For more information, see [Langmuir isotherm](#).

After you select **Adsorption** in the selection tree, these properties are displayed:

- V_{LS} , P_{LS} — Langmuir volume and Langmuir pressure (for shale).
- ρ_b — bulk density (for shale).

You can also select **Ads. Sat.** (adsorption saturation correction) in the selection tree, with the following properties:

- ρ_{ads} , S_{ads} — density of the adsorbed gas phase, and adsorbed gas saturation. For more information, see the [shale adsorption correction](#).

Geomechanical option

To include the effects of changing formation compressibility and permeability related to reservoir pressure, click the **Geomechanical** checkbox in the Analytical Model or Numerical Model pane.

For more information, see [geomechanical reservoir models](#).

Refracturing option

Horizontal multi-fractured wells are sometimes refractured after a few years of production. This is done to access new areas of the reservoir, and therefore increase production.

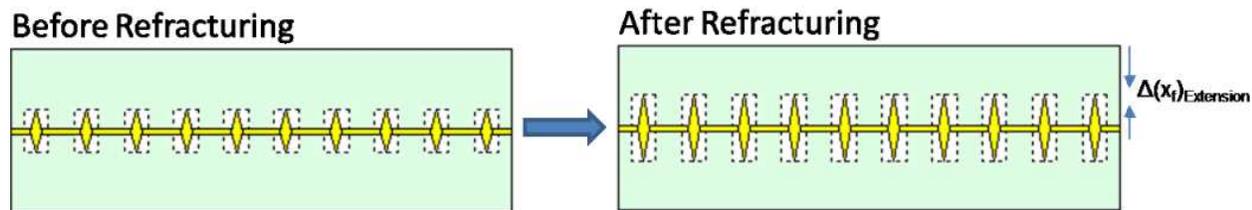
To use this feature, select the **Refrac** checkbox in the Numerical Model pane and set your refracturing date (t_{Refrac})

<input checked="" type="checkbox"/> Refrac	<input type="text" value="01/01/2000"/>	<input type="text" value="MM/DD/YY"/>
Fracture Extension		
$\Delta(x_f)_{\text{Extension}}$	<input type="text"/>	ft
$(k_{SRV})_{\text{Extension}}$	<input type="text"/>	md
Additional Fractures		
$(x_f)_{\text{Additional}}$	Required	ft
$(x_i)_{\text{Additional}}$	Required	ft
$(k_{SRV})_{\text{Additional}}$	Required	md

You can select either of these types of refracturing:

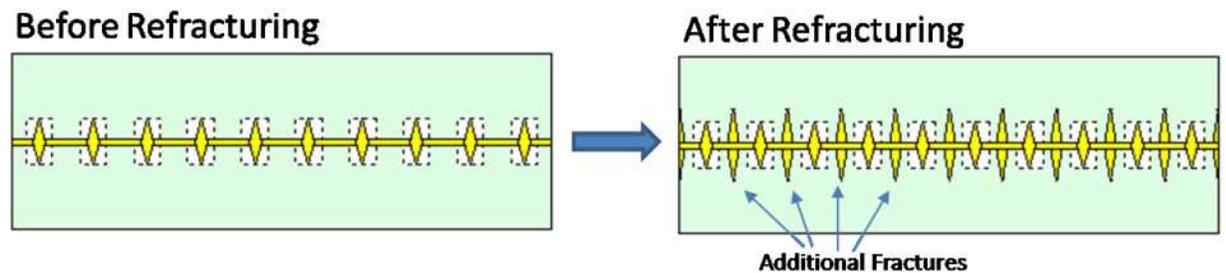
1. **Fracture Extension** — in this model, existing fractures are being extended.

Fracture Extension Schematic



2. **Additional Fractures** — in this model, new fractures are being added in the middle, between existing fractures.

Additional Fractures Schematic



Make sure to set the required parameters.

- **Fracture Extension model:**
 - $\Delta(x_f)_{\text{Extension}}$ — after refracturing, the fracture half-length becomes this much longer.

- $(k_{SRV})_{\text{Extension}}$ — the permeability of the stimulated region around the fractures *after* refracturing.

Note that after refracturing, the x-dimension of the stimulated region remains unchanged, and the y-dimension increases, such that it is equal to a new fracture length.

- **Additional Fractures** model:

- $(x_f)_{\text{Additional}}$ — the fracture half-length for additional fractures.
- $(X_l)_{\text{Additional}}$ — defines the x-dimension of the stimulated region around the additional fractures.
- $(k_{SRV})_{\text{Additional}}$ — the permeability of the stimulated region around the additional fractures.

Note that if the stimulated regions around the *original* fractures overlap with the stimulated regions around the *additional* fractures, permeability in the overlapping area is the maximum of k_{SRV} and $(k_{SRV})_{\text{Additional}}$.

Changing skin option

To include changing wellbore skin at specific points in time, click the **Chg. Skin** checkbox in the Analytical Model or Numerical Model pane.

For more information, see [time-dependent skin](#).

Sparse data option

When using sparse data, the numerical model uses coarse timesteps for calculations, and each coarse timestep contains n points.

Note: We recommend using sparse production data when running [automatic parameter estimation \(APE\)](#).

After you enter a value for n in the Use Sparse Production Data dialog box (opens when you click the **Use Sparse Data** icon ()) on the Numerical Model pane's toolbar, the history plot displays a new sparse set of production data to be used for calculations:

- Sparse rate data is displayed as thin lines (red for gas, green for oil or condensate, blue for water)

- Sparse flowing pressure is displayed as a thin brown line

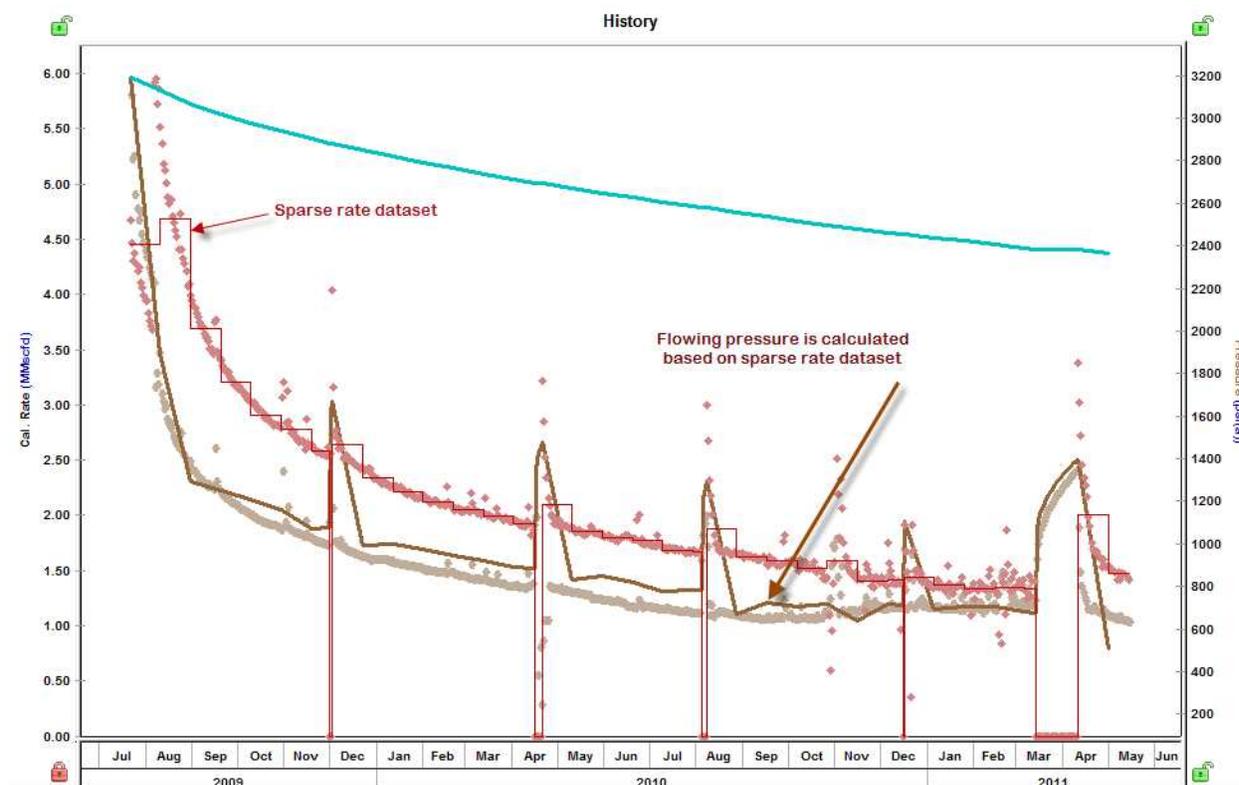
To ensure that the sparse dataset represents the actual production history, adjust the value for n , as required.

Click the **Synthesize** icon () to run the model. Note that the calculated results correspond to coarse timesteps.

If you run APE, each calculation runs using coarse timesteps based on your n value.

Note: Your weighting and point selection are honored when running APE using sparse data.

While calculation results are slightly less accurate, the calculations run faster. After APE finds a match using sparse data, you can run one calculation using the entire production dataset ($n = 1$) to ensure that the match is still good.



How sparse datasets are calculated

For Use Rate mode: Drawdowns are divided in coarse timesteps. Coarse timesteps contain n points, and the rate for each timestep is calculated as "total volume produced over the timestep"

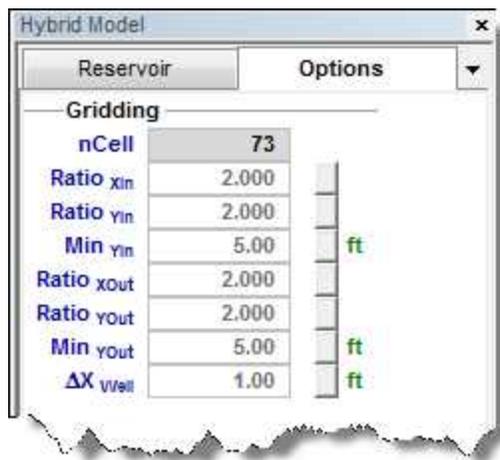
/ "duration of the timestep". For buildups, all of the production data is used.

For Use Pressure mode: Drawdowns are divided in coarse timesteps. Coarse timesteps contain n points, and the pressure for each timestep is calculated as "last-measured pressure of the timestep". For buildups, all of the production data is used.

Tip: You can select a rate or pressure in the Calculation Method section.

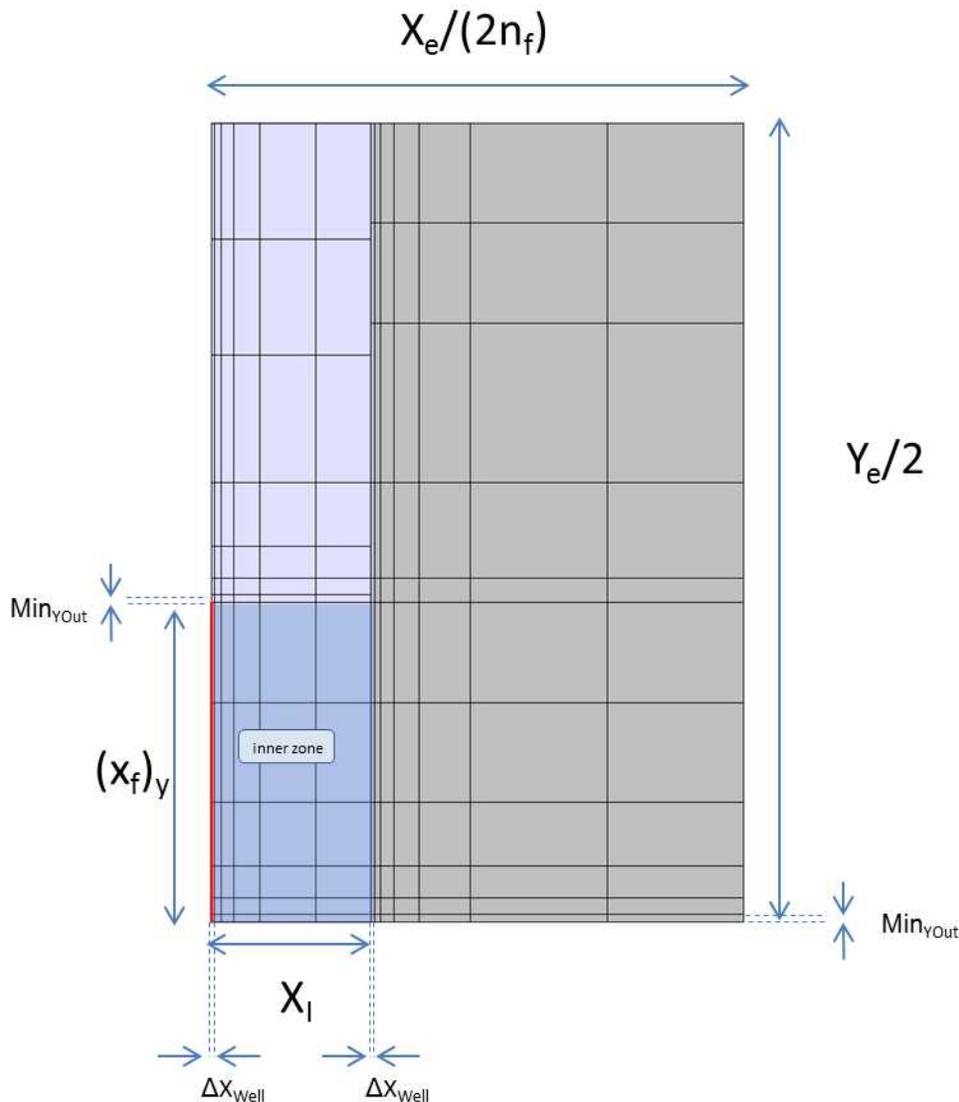
Adjusting gridding

After you set your reservoir and completion dimensions, Harmony Enterprise creates an appropriate grid for the model to get accurate results with minimal calculation time. The default gridding settings work well most of the time, but in some cases, you may want to adjust the gridding options by clicking the **Options** tab in the Numerical Model pane.



The figure below is a schematic of a model's grid for one quarter of a fracture stage.

- The *inner* zone has geometric gridding. The smallest cell in the inner zone is the cell containing the wellbore. Its dimensions are given by ΔX_{Well} and $Min y_{in}$. The geometric ratio for the x-dimensions of the grid cells is set by $Ratio X_{in}$ and the geometric ratio for the y-dimensions of grid cells is set by $Ratio Y_{in}$.
- The *outer* zones have geometric gridding. The smallest cell in the outer zones have dimensions given by ΔX_{Well} and $Min y_{out}$. The geometric ratio for the x-dimensions of grid cells is set by $Ratio x_{out}$ and the geometric ratio for y-dimensions of grid cells is set by $Ratio y_{out}$.
- The *nCell* field displays the total number of grid cells used to model one quarter of a fracture stage. This number is important because it directly affects the model's calculation time. This field is populated after you run your model calculations.



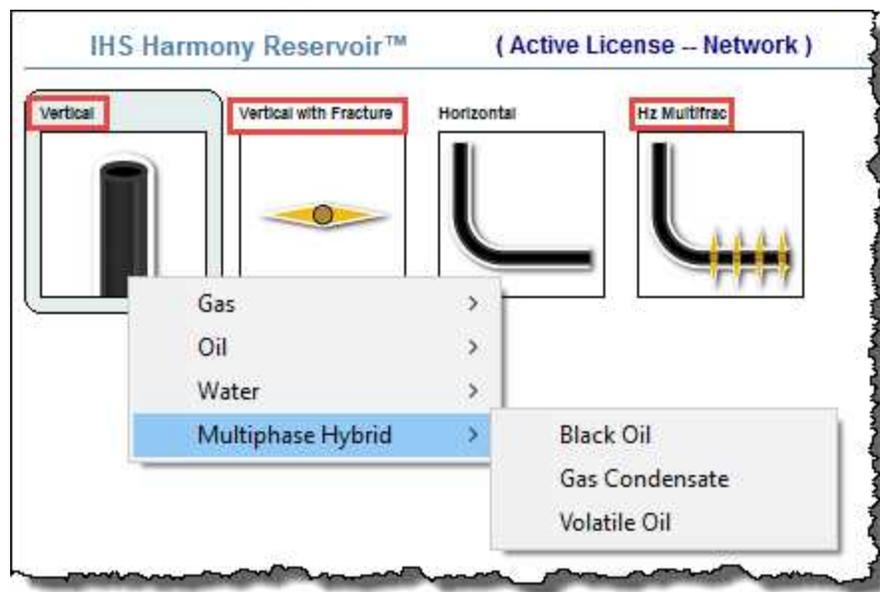
Probabilistic analysis

A probabilistic analysis works by repeatedly running a numerical model to generate a range of forecasts. For each run, the values for the majority of the parameters are taken from the base numerical model, and values for parameters that are uncertain, are drawn from given distributions. As a result, you get a range of forecasts and a distribution for values of expected ultimate recovery (EUR).

Note: This analysis works with your IHS Reservoir™ license.

A probabilistic analysis can be run on any numerical analysis with valid parameters and a forecast.

If values for some of a numerical model's parameters are uncertain, but you have some idea about their range and distribution, you can use a probabilistic analysis to account for this uncertainty.



A probabilistic analysis has three tabs: Setup, Dependencies, and Results.

Setup tab

This tab contains parameters for the probabilistic analysis, and cards where you can define the distributions for parameters.

To indicate that a parameter's value is uncertain, click the **Add Parameters** icon (), and select the parameter from the drop-down list. A distribution card is added to this tab where you can define the distribution to be used for this parameter.

Number of runs

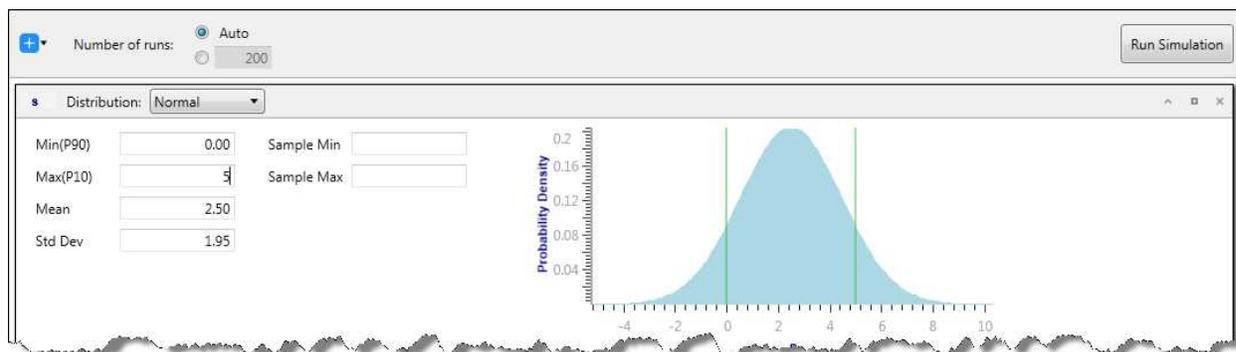
Probabilistic simulation may take a long time, especially if the number of runs is high.

You can set your number of numerical-model runs in the simulation as follows:

- **Auto** — automatically detects when the P50 forecast has converged, and is no longer changing significantly with additional runs. We recommend using this setting because it can drastically reduce the number of runs required to achieve a good result.
- **Specific number** — runs the number of runs you specify.

Run simulation

After you add and set up distribution cards for all your uncertain parameters, click the **Run Simulation** button to start your simulation.



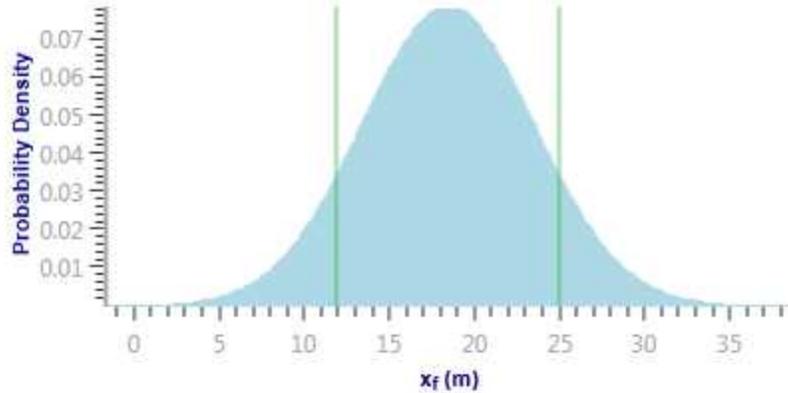
Distribution cards

After you add distribution cards for your uncertain parameters, you can select one of these distribution types: normal, log-normal, triangular, or uniform. For more information, see the descriptions below and probabilistic theory.

With some parameters, you can select automatic parameter estimation (**APE**) from the **Distribution** drop-down list. For more information, see APE.

Normal

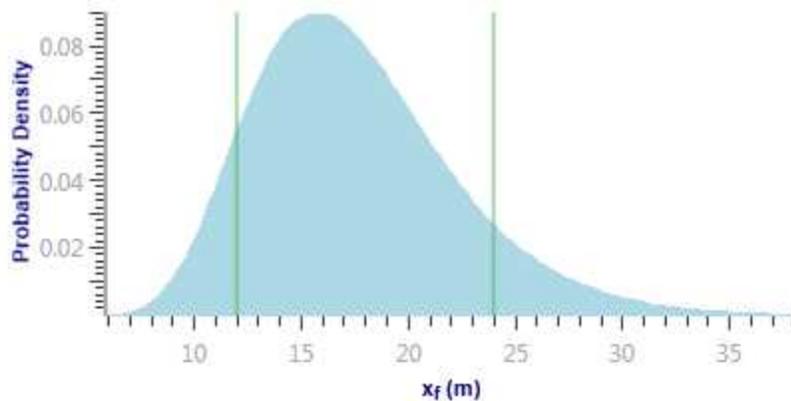
By selecting Normal, you can apply a normal distribution to a particular parameter by entering a mean and variance, or a Min (P90) and Max (P10).



Additionally, you can enter a Sample Min and Sample Max for a normal distribution. In this case, the distribution is truncated, and the probability function is adjusted such that the total probability still sums up to 100%. For more information, see [truncated distributions](#).

Log-Normal

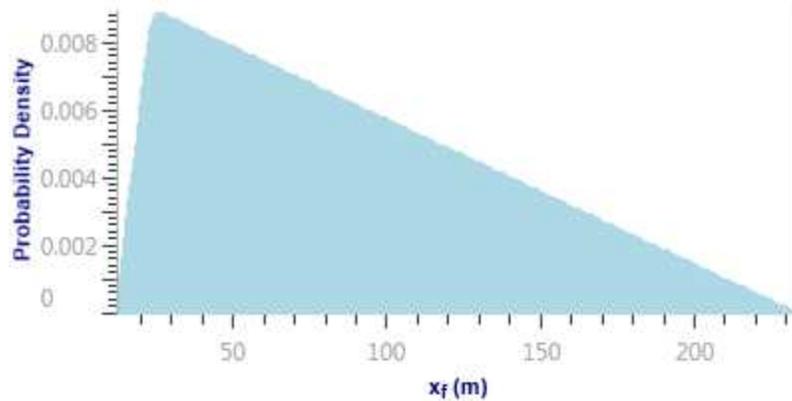
By selecting Log-Normal, you can apply a log-normal distribution to a particular parameter by entering a mean and variance, or a Min (P90) and Max (P10).



Additionally, you can enter a Sample Min and Sample Max for a log-normal distribution. In this case, the distribution is truncated, and the probability function is adjusted such that the total probability still sums up to 100%. For more information, see [truncated distributions](#).

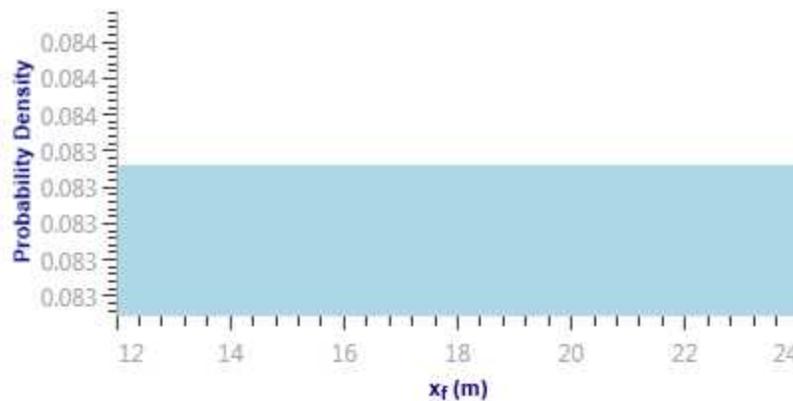
Triangular

By selecting Triangular, you can apply a triangular distribution to a particular parameter by entering a minimum, mode, and maximum. The minimum and maximum values define the extent to which the probability density is equal to zero. The mode defines the peak.



Uniform

By selecting Uniform, you can apply a uniform distribution to a particular parameter by entering a minimum and maximum.



APE

In a typical scenario, you would run probabilistic analysis for a numerical model that matches historical data. However, after you change the values for uncertain parameters based on a given distribution, the history match is likely to get spoiled. You may want to adjust some other parameters to restore the match. To do this, set the distribution for those additional parameters to APE.

APE iteratively varies the value of a parameter and attempts to minimize the total error between the measured data and the simulated values. When the model uses a rate to calculate pressure, it minimizes the difference between the simulated and measured pressures. When the model uses pressure to calculate rates, it minimizes the difference between the measured and simulated primary fluid rate. Only the primary fluid rate match is minimized.

For each probabilistic run, the best match that APE could find is used to generate a forecast. There is no filtering of these results based on the quality of the match found by APE.

Example:

Assume you have a base numerical model that matches historical data, and this model has $x_f = 120$ ft. In reality, you are not certain if the value of x_f is indeed 120 ft, but based on the available information, you can confidently assume that x_f is varying between 80 ft and 160 ft, and can set the distribution for x_f to Normal.

For each run within the probabilistic analysis, Harmony Enterprise picks a value for x_f based on the given distribution. Simply changing the value for x_f results in runs that do not match the historical data.

To mitigate this problem, set the distribution for k_{SRV} and/or k_{matrix} to APE. In this case, for each run within the probabilistic analysis, Harmony Enterprise picks x_f based on the given distribution, and then runs APE on k_{SRV} and/or k_{matrix} (keeping x_f at the value drawn from the given distribution).

Using APE for some of the model's parameters ensures that all probabilistic runs match historical data as closely as possible. However, it is important to keep in mind that when using APE, each probabilistic run requires many runs of the numerical model; therefore, the overall simulation time increases significantly.

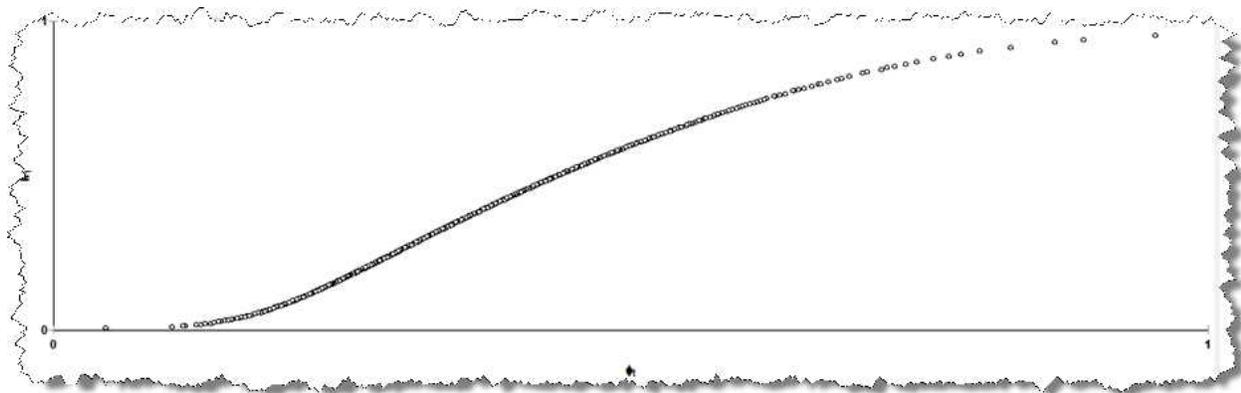
When running APE on a certain parameter, you can set user-defined limits for it by clicking the **View Defaults and Limits** button () to the right of the parameter in the base model.

Dependencies tab

After values are sampled during simulation, they are displayed in this tab where relationships between any of the uncertain parameters can be entered. For example, if you know that the porosity and permeability in the reservoir are proportional, a correlation coefficient can be entered to represent this relationship. These values must be between -1 and 1, and must be entered in the field that intersects the two desired variables.

Set Up		Dependencies	
	p_i	k_{inner}	μ_t
p_i	1		
k_{inner}		1	1.000
μ_t		1.000	1

The lower plot displays a cross-plot for the variables you select in the above table.



If you set up more than two parameters in the Setup tab, correlation coefficients between each pair of parameters are not independent. After you enter the correlation coefficients, a **Correct the matrix** button appears. Click this button to adjust the coefficients you enter, such that the coefficients for each pair become consistent.

Set Up		Dependencies	
Before			
	x_f	k_{matrix}	c_f
x_f	1	1.000	
k_{matrix}	1.000	1	0.200
c_f		0.200	1

Correct the matrix

Set Up		Dependencies	
After			
	x_f	k_{matrix}	c_f
x_f	1	0.980	0.002
k_{matrix}	0.980	1	0.197
c_f	0.002	0.197	1

Results tab

In this tab, a dashboard view is displayed.



After your simulation runs are complete, you can export your data to Excel by clicking the **Export Data** icon (📄).

To take the varied parameters from the first probabilistic run and populate them in the base model in the Numerical Model pane, click the  icon.

Tip: If you see a warning that the "Source model changed", you may need to re-run the simulation on the Setup tab, or the base numerical model to clear the warning. The base model can get out-of-date when auto-calculate is deselected (see AutoCalc) and you make changes to parameters (that is, the results become out-of-date).

Filter — you can filter the cases / runs used in determining the P90, P50, and P10 based on a cut-off for the average error (E_{avg}) of each run.

In every model's run, an average error (E_{avg}) is determined: it is calculated as described in automatic parameter estimation theory.

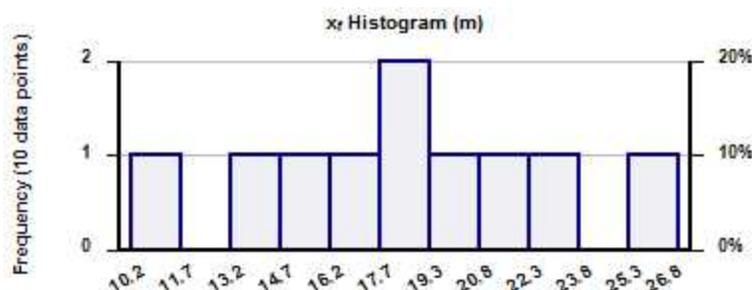
The average error represents the quality of a match. When you are viewing the variation of model runs, it is useful to be able to exclude any runs that produce a "bad" match. To do this, click the

Filter drop-down list above the Rate vs Time plot and select **Add Filter**. Type a value for the error cut-off (between 0 and 1). All the runs with E_{avg} above the entered value are excluded when calculating probabilistic results (P90, P50, and P10). Or, you can leave the Filter as **None**. In this case, the E_{avg} used for cut-off is calculated as 1.5 times the average of all the E_{avg} values from the probabilistic runs.

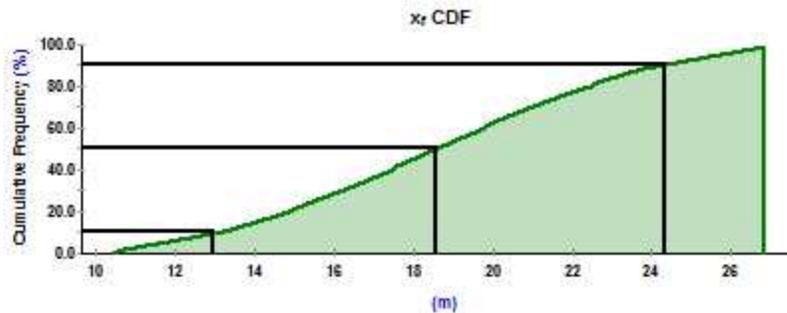
Tip: Any E_{avg} cut-offs you enter are saved within your current session, but are not saved to the database.

By default, these views are displayed from the upper left to lower right:

- **Rate vs Time** — your historical data, range of generated forecasts (displayed as shaded areas), P90, P50, and P10 forecasts (see [percentile calculations](#)) are displayed. Data is displayed with rate on the y-axis and time on the x-axis. For multiphase cases, you can switch between available fluids by clicking one of the **Show Fluid** icons (● ● ●).
- **Rate vs Cumulative** — your historical data, along with range of generated forecasts (displayed as shaded areas), P90, P50, and P10 forecasts (see [percentile calculations](#)) are displayed. Data is displayed with rate on the y-axis and cumulative production on the x-axis. For multiphase cases, you can switch between available fluids by clicking one of the **Show Fluid** icons (● ● ●).
- **Summary table** — your parameters are displayed in a summary table.
- **Parameter Distribution plot** — when you select a parameter in the summary table, the lower-right plot displays the probability distribution for the selected parameter. You can display the distribution as either a Histogram or a cumulative distribution function (CDF). Toggle the **Switch Plot** icon (▭ / ▴) to switch between these two plots.
 - A histogram is a graphical representation of a distribution of data. It is an estimate of the probability distribution of a variable. The dataset is split up into bins (ranges) on the x-axis, and the y-axis plots the frequency at which the data falls in each bin. Only one result variable can be plotted on a histogram at a time.



- A CDF calculates the probability that a random variable with a given probability distribution is found at a value less than or equal to "x". Only one result variable can be plotted on a CDF plot at a time. The black horizontal lines originating at cumulative frequencies of 10%, 50%, and 90% intersect the CDF curve, and then line up with the P90, P50, and P10 values of that dataset, respectively.

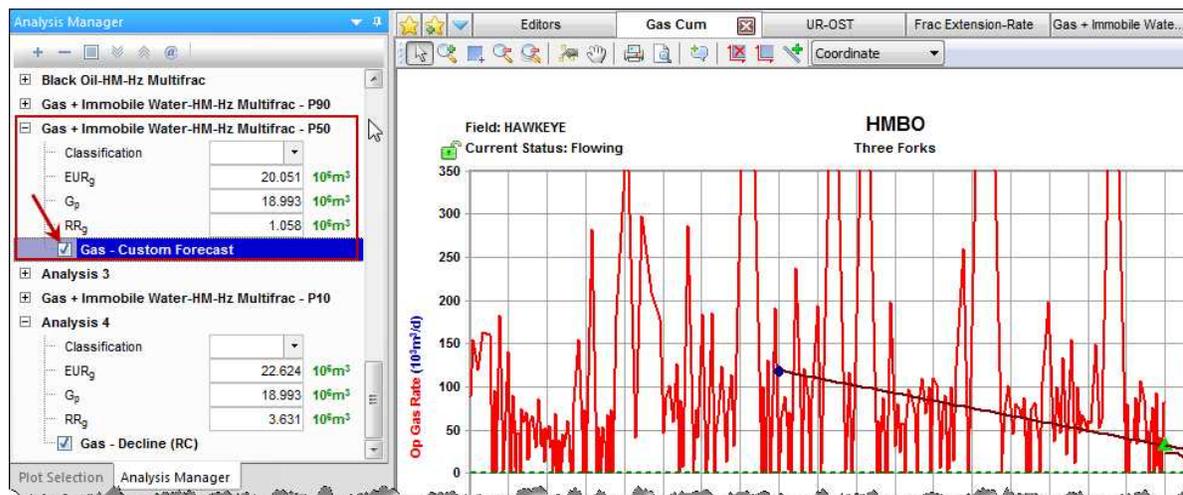


Displaying results

After the probabilistic simulation is complete, Harmony Enterprise creates P10, P50, and P90 forecasts based on all the successful runs within the probabilistic simulation. Remaining recoverable (RR) volumes and EUR volumes are calculated for these forecasts. For more information on calculations, see [percentile calculations](#).

In some regards, P10, P50, and P90 forecasts (also called percentile forecasts) can be treated as separate analyses in Harmony Enterprise. For example, you can:

- View percentile forecasts in the [Analysis Manager](#). You can toggle these forecasts on or off by clicking their checkboxes in the tree structure.
- Display percentile forecasts on decline plots. Toggling a percentile forecast on in the Analysis Manager displays the forecast in the decline plot.



- Fit the decline analysis to match the percentile forecast. In the Analysis Parameters toolbar, you can click the Fit Decline to Forecast and Selected Production Points icon () to fit the decline analysis to your percentile forecast.
- Display RR and EUR for percentile forecasts in the Results Viewer.

		Summary Parameters	
		Gas	
Display Name	Analysis Name	EUR _g	RR _g
		MMscf	MMscf
1	HMBO Hybrid Model	391	4
2	HMBO Hybrid Model - P10	428	41
3	HMBO Hybrid Model - P50	408	21
4	HMBO Hybrid Model - P90	391	4

Percentile calculations for input parameters, forecasts & EURs

After the probabilistic analysis is run, and all the runs are completed, Harmony Enterprise generates percentiles (P10, P50, P90) for input parameters, percentile forecasts, and percentile expected ultimate recovery (EUR) volumes. Details about these calculations are given below.

Percentile (P10, P50, and P90) input parameters and OFIPs

Input parameters and original fluid-in-place (OFIP) values are calculated using the following steps:

1. Consider all the successful runs generated by the probabilistic analysis.
2. Calculate P10 for a certain input parameter as a P10 percentile of values for this parameter for all successful runs. (Do the same thing for the P50 and P90 values.)
3. Calculate P10-OFIP as a P10 percentile of values for OFIP for all successful runs. (Do the same for the P50 and P90 OFIPs.)

Percentile (P10, P50, and P90) forecasts

These forecasts are calculated using the following steps:

1. Consider all the successful runs generated by the probabilistic analysis.
2. At each timestep, calculate a P10-rate as a P10 percentile of rates at this timestep for all successful runs. (Do the same for P50 and P90 rates.)
3. Calculate a P10 forecast by combining all the rates calculated in step 2. (Do the same for the P50 and P90 forecasts.)

Note: Percentile forecasts do not correspond to any of the runs generated by the probabilistic analysis. Therefore, there is no combination of input parameters that results in a forecast that is equal to the percentile forecast.

Percentile (P10, P50, and P90) EURs

EURs are calculated using the following steps:

1. Calculate P10, P50, and P90 remaining recoverable (RR) volumes by summing up production based on P10, P50, and P90 forecasts.
2. Calculate P10, P50, and P90 EURs as:
 - P10 EUR = Historical cumulative production + P10 RR
 - P50 EUR = Historical cumulative production + P50 RR
 - P90 EUR = Historical cumulative production + P90 RR

Note: The P10 EUR calculation shown above is *not the same* as considering EUR values for all the successful runs generated by a probabilistic analysis and calculating a P10 percentile among them. (This is also true for P50 and P90 EURs.)

Tips: speeding up the probabilistic analysis

With the probabilistic analysis, the numerical model is run multiples times; therefore, the simulation may take significant time. Below are few tips to make the probabilistic analysis run faster.

Base numerical model

Before setting up and running a probabilistic analysis, ensure that the base numerical model is in a good shape:

- The base model should match historical data reasonably well, and the simulation time for the base model should not be too long.
- If you are planning to use automatic parameter estimation (APE) within the probabilistic analysis, test APE on the same parameters for the base model *first*. Make sure you deselect outliers, and set user-defined limits for those parameters, if required.
- Consider using the sparse data option to speed up the base model. If this option increases speed and retains acceptable accuracy for the base numerical model, you can use it for the probabilistic analysis as well.
- Consider adjusting gridding to speed up the base model. If this option increases speed and retains acceptable accuracy for the base numerical model, you can use it for the probabilistic analysis as well.

APE

If some of the uncertain parameters are set to APE, the probabilistic analysis requires more numerical model runs, and therefore takes longer time. In many cases, it is required to have at least some of the model parameters varied by APE to achieve a history match for each probabilistic run. However, we recommend that you keep the number of such parameters to a minimum (one or two).

Changes that affect properties

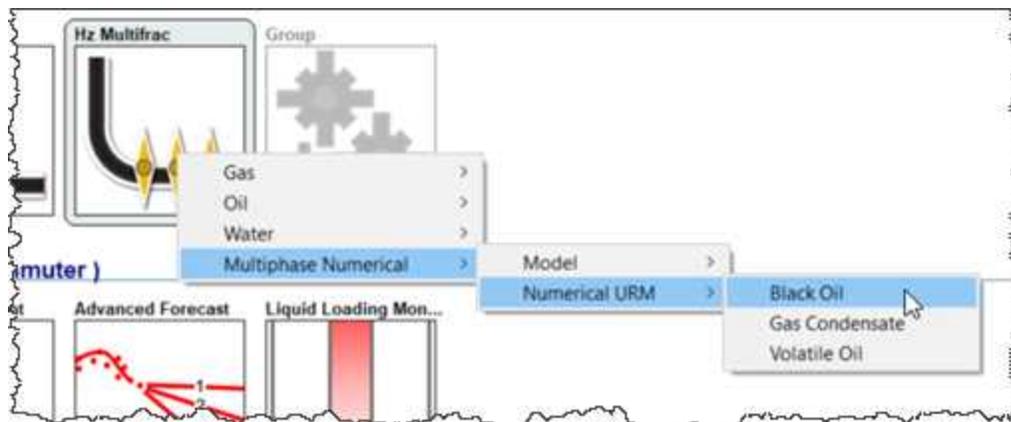
Due to the way the numerical model uses properties, calculations can require additional time whenever properties change. Therefore, we recommend to *not* include the following parameters in the list of uncertain parameters:

- p_I (initial reservoir pressure)
- γ (permeability module under the Geomechanical group)
- Fluid saturations
- c_f (formation compressibility)

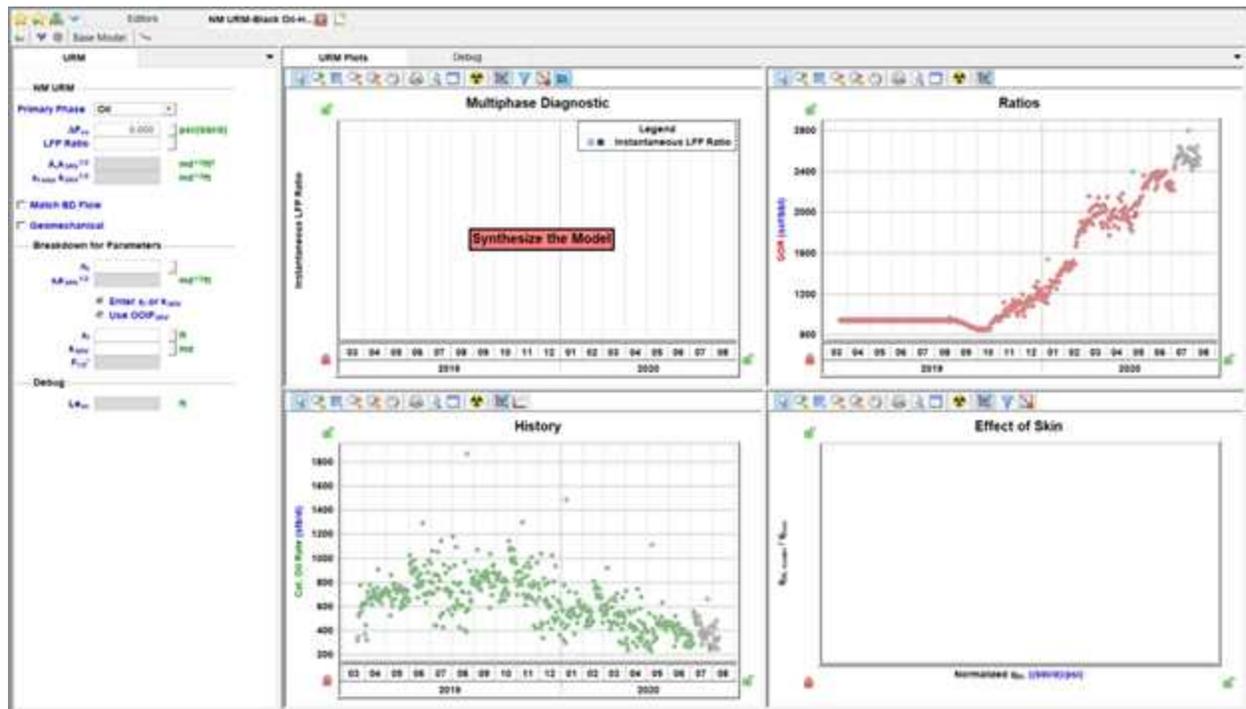
- ϕ_t (porosity)
- h (net pay)

Numerical URM

We recommend reviewing the [methodology summary](#) prior to conducting this analysis for the first time. The numerical unconventional reservoir module (URM) [worksheet](#) is accessible by clicking the **Hz Multifrac** thumbnail.

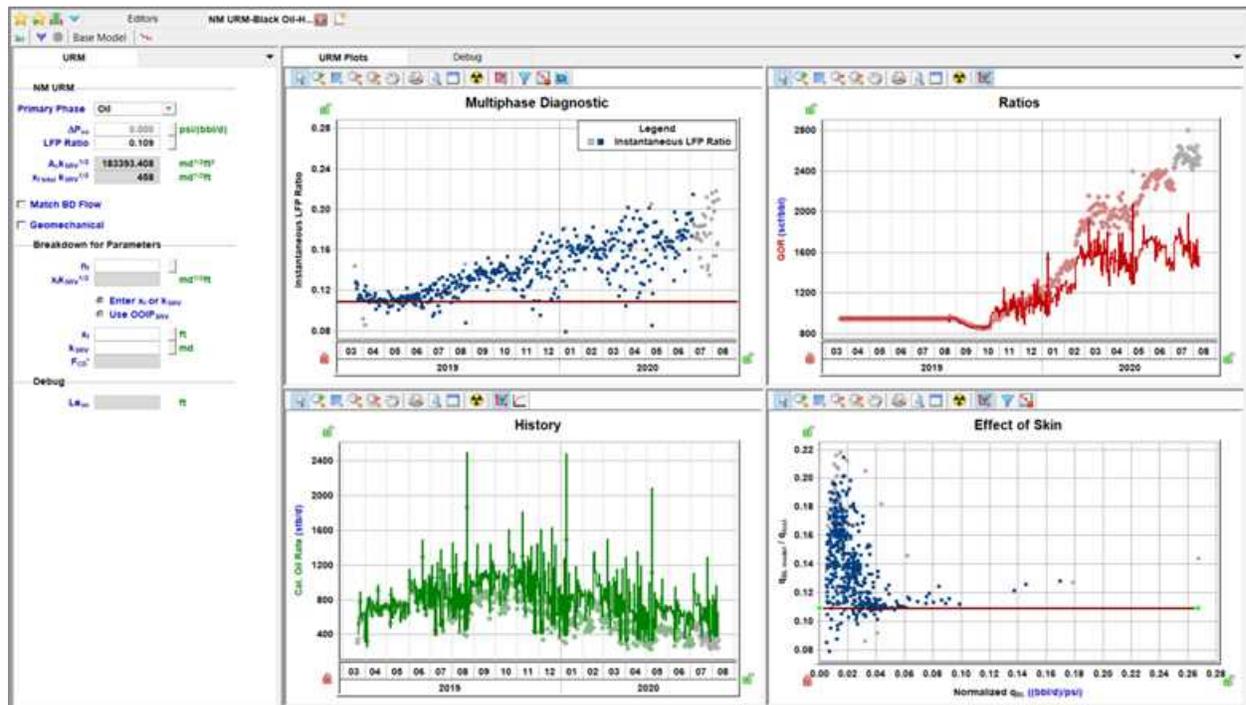


In a newly created worksheet, only the History plot and Ratio plot are populated, showing the historical data for the well.



To begin, click the **Synthesize** icon () to run the base model, which is used to calculate the data points displayed in the Multiphase Diagnostic and Effect of Skin plots. The History and Ratios plots also display a synthetic line generated from the base model results.

To use numerical URM, start with the Multiphase Diagnostic plot. The horizontal line on this plot represents the linear flow parameter (LFP) ratio used to determine $A_c\sqrt{k_{SRV}}$ and starts as a fit of the first 25% of the data. Adjust this line on the plot, or type a new value for the LFP ratio to match the flat portion of your data points. When this is matched, the synthetic lines on the History and Ratios plots should also look like a good match to your data during the linear flow portion (the duration that is flat on the Multiphase Diagnostic plot).



If you are only interested in analyzing the linear flow data, you can now type the n_f in the Breakdown for Parameters section and type either x_f or k_{SRV} to have the other calculated from $A_c \sqrt{k_{SRV}}$. This can then be used in models or for other analyses.

We recommend starting your analysis with $\Delta P_s = 0$ (no additional pressure drop) and leaving the analysis line on the Effect of Skin plot flat. However, additional pressure drop can be accounted for if:

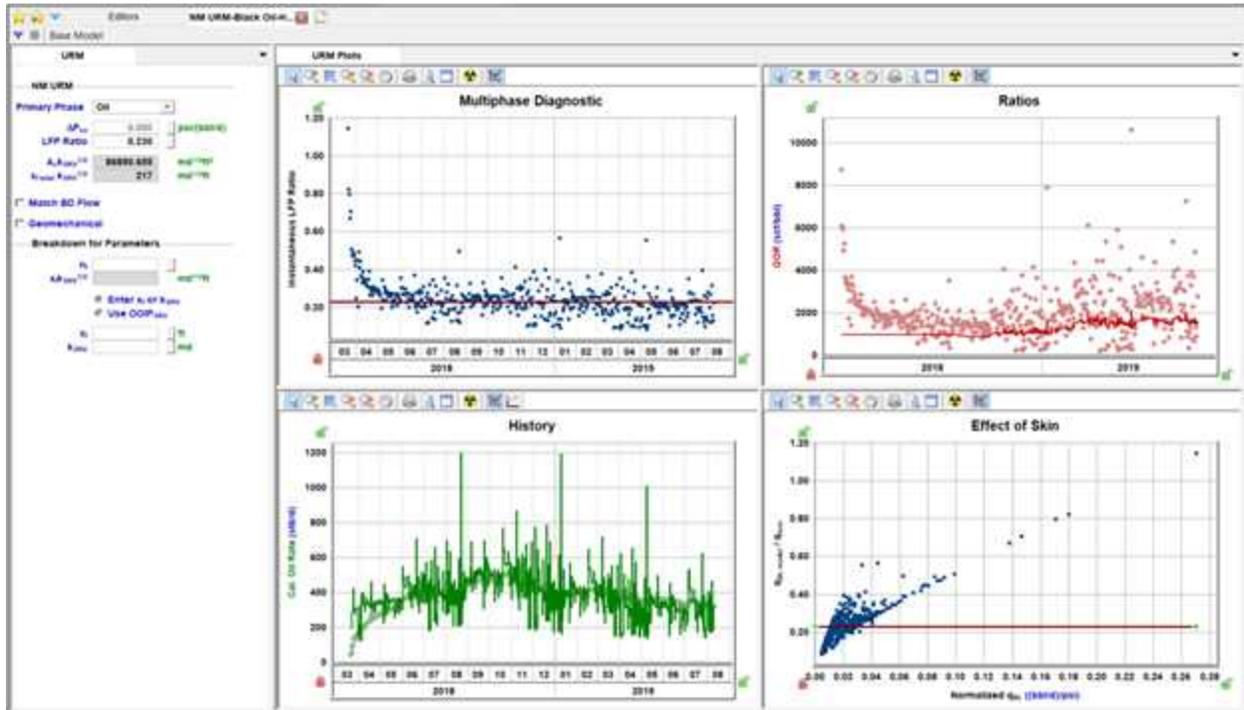
- A declining trend is observed in the early-time data of the Multiphase Diagnostic plot, and
- Points on the Effect of Skin plot follow an increasing straight-line trend

To account for additional pressure drop:

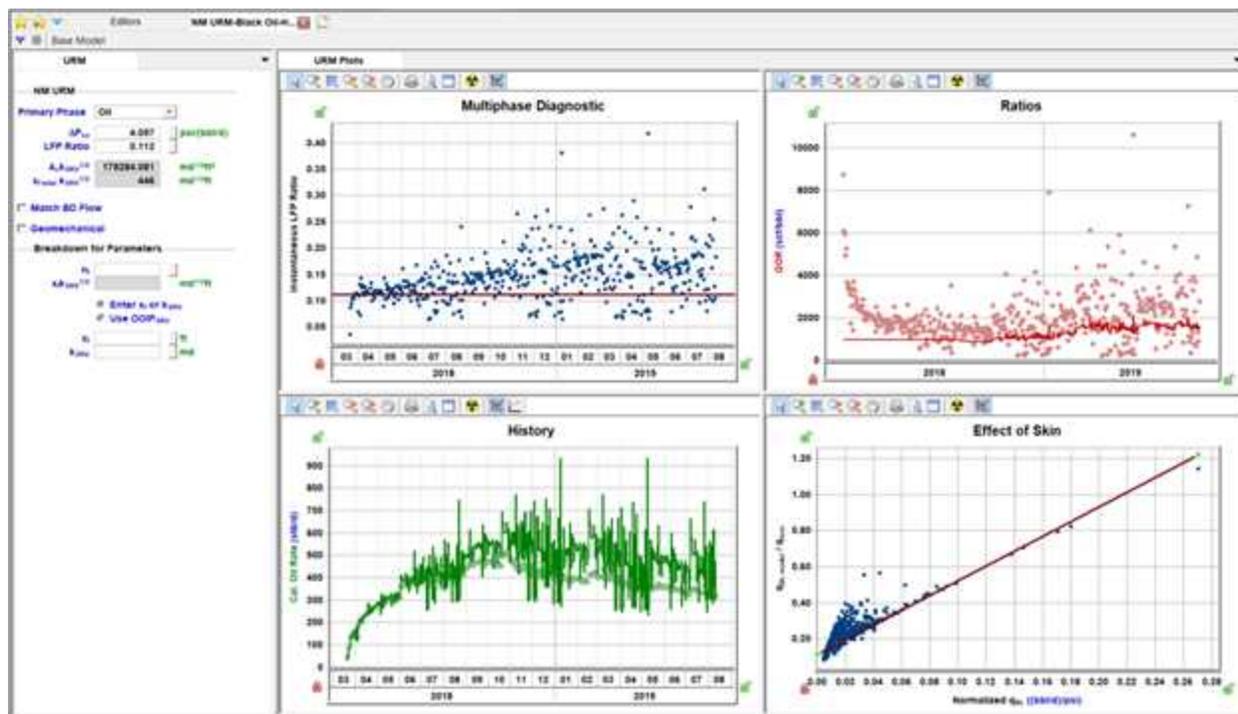
1. Adjust the straight line on the Effect of Skin plot, or change the value of ΔP_s to match the trend.
2. The Multiphase Diagnostic plot adjusts accordingly (the decreasing trend at the beginning should flatten) — adjust the horizontal LFP line on this plot, if needed.
3. The synthetic line on the History plot also adjusts — check if the match is good, both at the early flow and during the first linear flow.

Note: Real data is usually scattered on the Effect of Skin plot. As a result, identifying a straight line with a positive slope can be quite challenging.

Without ΔP_s :



With ΔP_s :



If data is too scattered and the match is non-unique on the Effect of Skin plot, use the Multiphase Diagnostic plot and make sure the flat line is fitted through the transient linear flow portion of the data.

As a result of accounting for the additional pressure drop, you may get more accurate result for the $A_c\sqrt{k_{SRV}}$ value. This also indicates that you need to use a lower fracture conductivity in order to model the dataset numerically.

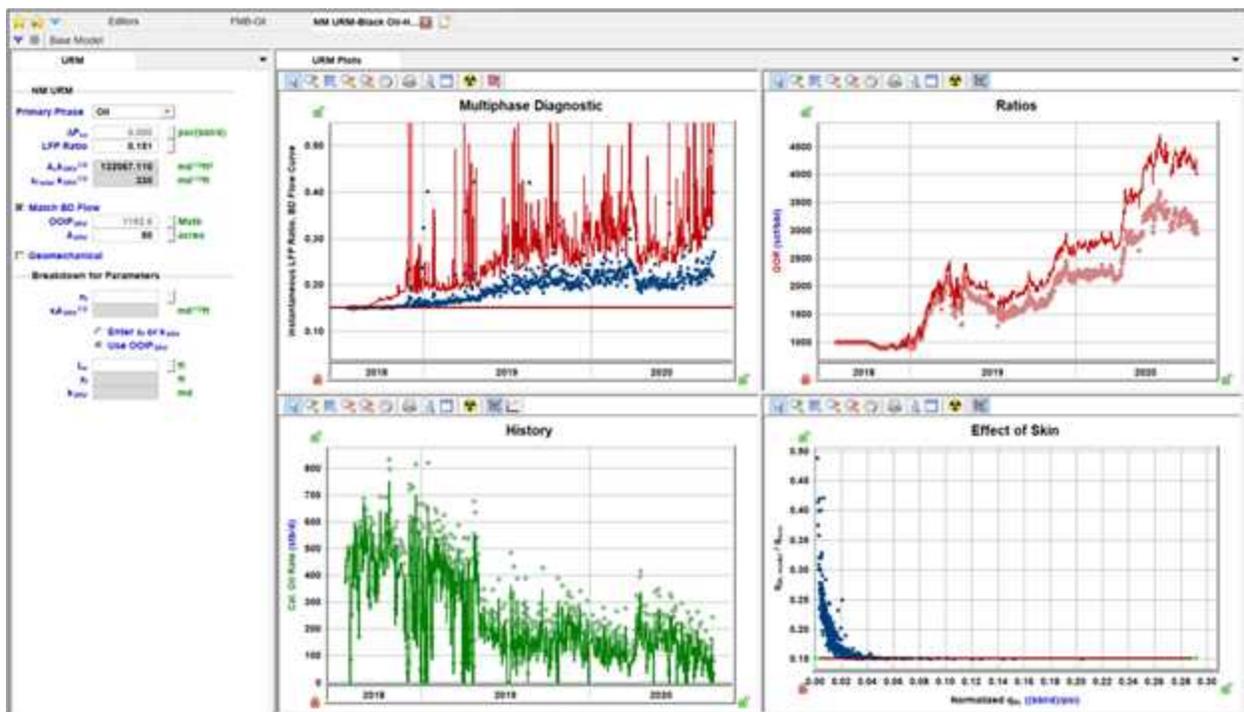
Matching boundary-dominated flow

If your data shows a clear transition out of linear flow, you may want to match the later data with an A_{SRV} or $OFIP_{SRV}$. Start by selecting the checkbox for **Match BD Flow** so the inputs are displayed.

- You can click the **View Defaults and Limits** buttons (📄) on the right of the input fields to pull A_{SRV} or $OFIP_{SRV}$ from other analyses, such as FMB.
- You can also directly type a value and the other value is calculated. The $OFIP$ stems can be used as a guide for entering a value.
- You can use the Auto Match button to provide an estimate if:

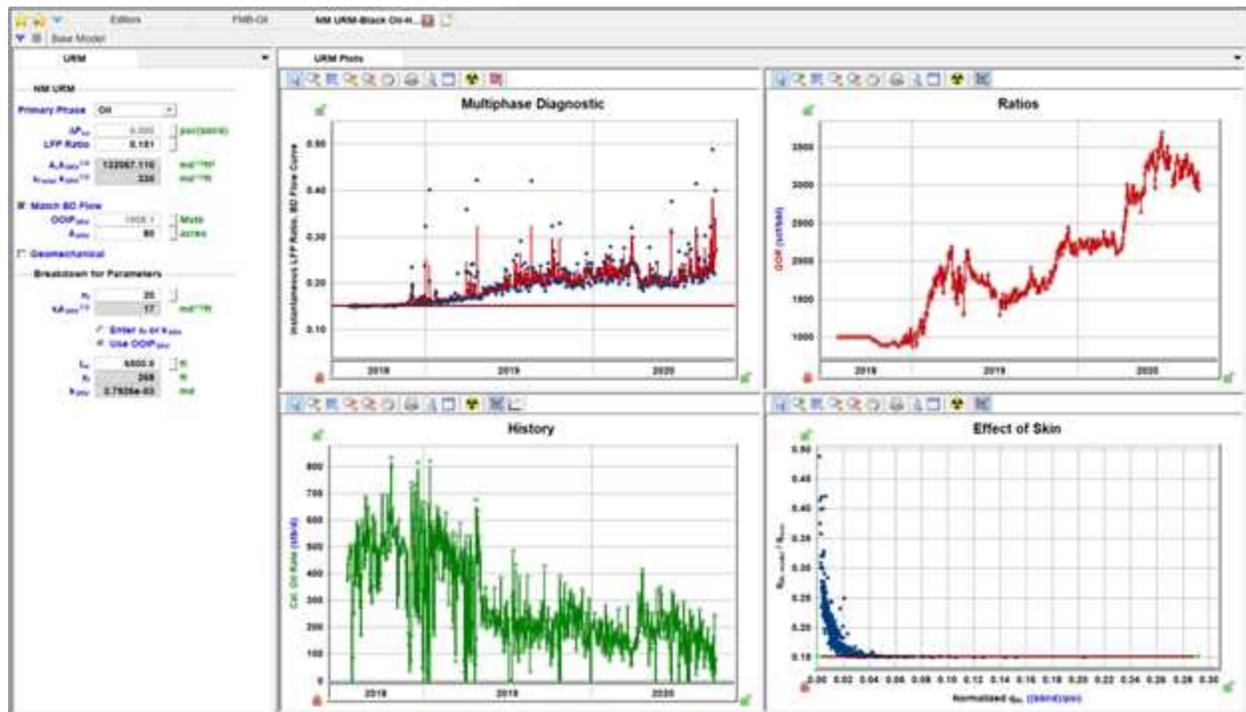
- OFIP stems are in the same range as the well data.
- you clean up very noisy data (corrections to well data or you click the **Smooth Base Model Rates** icon). Or, you filter noisy data from analysis so this data does not influence error minimization.

After AS_{RV} or $OFIP_{SRV}$ are populated, click the **Synthesize** icon () to calculate a boundary-dominated match from the base model. A synthetic line is displayed on the Multiphase Diagnostic plot, and the History and Ratios plots have synthetic lines based on the boundary-dominated match.



The synthetic line on the Multiphase Diagnostic plot is a good indication of the quality of the boundary-dominated match. If the synthetic line is above your data, try a larger AS_{RV} or $OFIP_{SRV}$. If the synthetic line is below your data, try a smaller value.

Better match:



Similar to the linear flow match, after you are satisfied with the match to your data, you can populate the inputs in the Breakdown for Parameters section to get specific results. When **Match BD Flow** is used, the L_e for your well can be used in combination with the A_{SRV} to calculate both x_f and k_{SRV} .

Primary toolbar

The primary toolbar has the following icons:

- **Defaults** — copies parameters from the Properties editor or other Reservoir worksheets.
- **Synthesize** — recalculates the model.
- **Stop Synthesize** — stops the model's synthesize calculations.
- **Base Model** — toggle between displaying the URM tab, or multiple tabs: URM, Base Model, OFIP Stems, Options.
- **Smooth Base Model Rates** — applies base model rates for base linear, OFIP stems, and boundary-dominated flow curves using a moving average.

Plot dashboard

The plot dashboard displays the following plots: Multiphase Diagnostic, Ratios, History, and Effect of Skin.

Plot toolbars

The icons displayed in the plot toolbar vary depending on the plot. The important icons are described below.

-  **Reset Plot Attributes** — resets your plot attributes to its original settings.
-  **Data Filter** — opens the [Data Filter dialog box](#) where you can apply a data filter.
-  **Hide Disabled Points** — when disabled points are filtered out, they can be hidden from the plot instead of being displayed in gray.
-  **Show OFIP Stems** — base models of varying L_e are displayed as a comparison with the actual data, in order to guide boundary-dominated (BD) flow matching.

For a description of common plot icons, see [plot toolbars](#).

Using OFIP stems

The purpose of the OFIP stems is to provide a comparison between the actual well behaviour and a series of known reservoir volumes. The stems are used to help you match the $OFIP_{SRV}$, either manually or with the Auto Match tool.

When you create a new Numerical URM worksheet, the OFIP stems are displayed by default. They can be hidden by toggling the **Show OFIP Stems** icon () . You may want to hide the OFIP stems while matching the linear flow portion of your data to reduce the content displayed on the Multiphase Diagnostic plot.

The OFIP stems are defined using scaling factors to the Base Linear model. This means the L_e for each stem model is the L_e of the Base Linear model multiplied by the scaling factor. There are a series of seven stems available to you and they cannot be displayed individually. While defaults have been provided, the best stem sizes are highly variable, and we recommend that you adjust these in order to bound your well data. If all the stems appear lower than your well data, the $OFIP_{SRV}$ of the stems is too large, and you should reduce the size of some stems. If all the stems

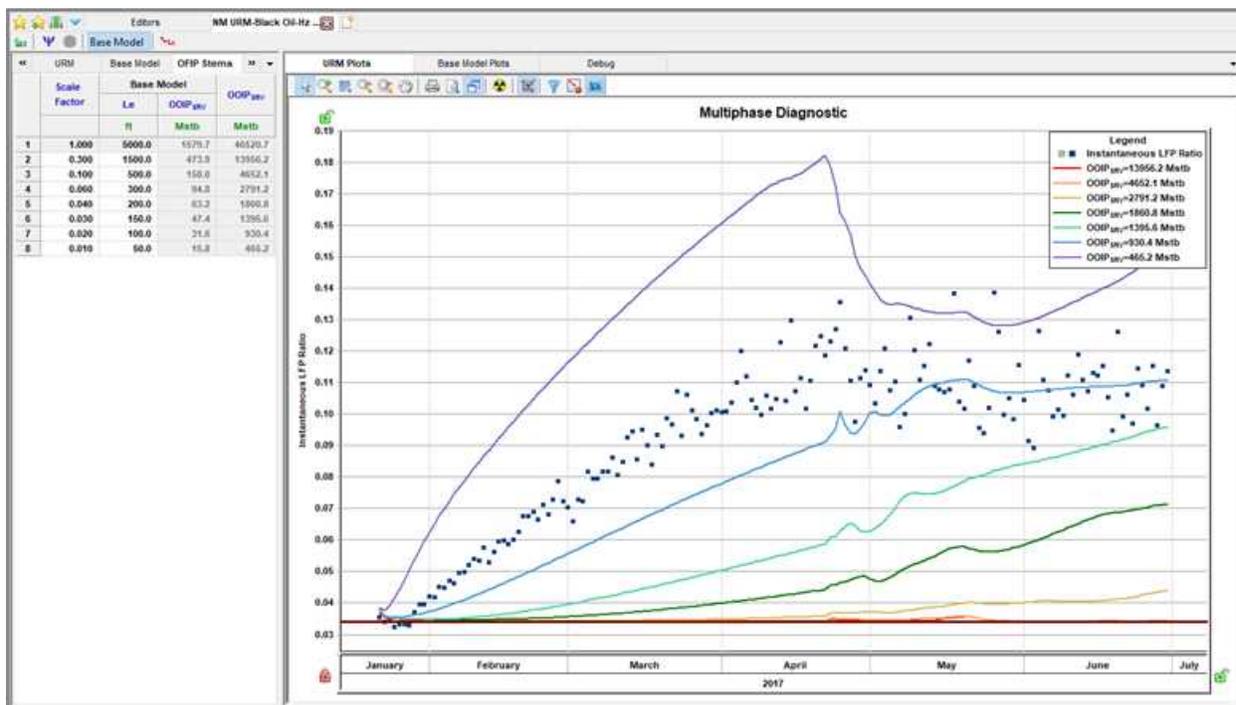
appear above your well data, the $OFIP_{SRV}$ of the stems is too small, and you should increase the size of some stems.

To modify the stems:

1. To display additional tabs for Numerical URM, click **Base Model** on the toolbar.
2. Click the **OFIP Stems** tab.
3. Modify the scaling factor or L_e values in the table.

This table automatically sorts from largest to smallest values, and you can type a new value over any stem you want to replace.

4. To run the base model and display your new stems, click the **Synthesize** icon () on the toolbar .



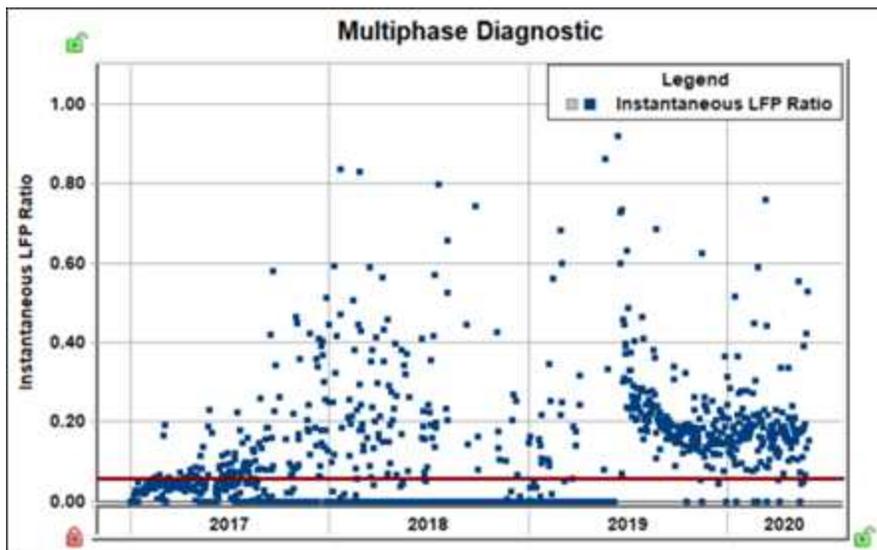
Base model rate smoothing

Errors and fluctuations are a normal part of daily production data. Most interpretation methods simply require a method of filtering out these noisy points to observe the reservoir behavior more clearly. The numerical URM method uses a numerical model to generate the data points for interpretation. While some data points can be filtered, the base model is run using all the flowing

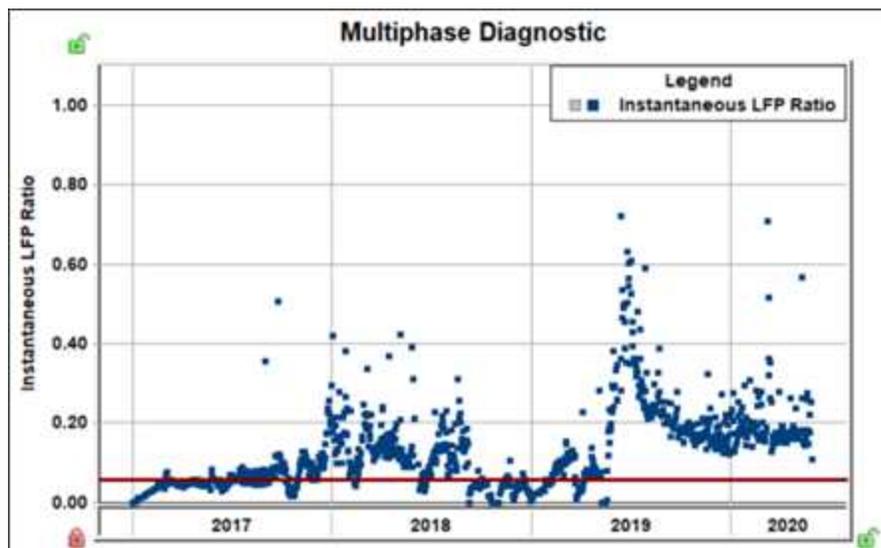
pressure data for the well with filtering applied to hide these points afterwards. This means that filtering points does not remove their impact on subsequent timesteps in the base model. The result is an amplification of noise in the calculated rates from the base model. Most often this is seen as false shut-ins that display as a large number of zeroes on the Multiphase Diagnostic plot.

If noisy data cannot be resolved by cleaning up or correcting your production history, a smoothing option is available. By clicking the **Smooth Base Model Rates** icon (🔧) in the toolbar, all base model rates are smoothed using a moving average. The default period size for this moving average is 20, but it can be modified in the Options tab. Click the right arrows icon (➡) if this tab is hidden. If you use smoothing, you do not need to synthesize again, because the moving average smoothing is performed on the actual synthetic rates from the base model.

Before smoothing:

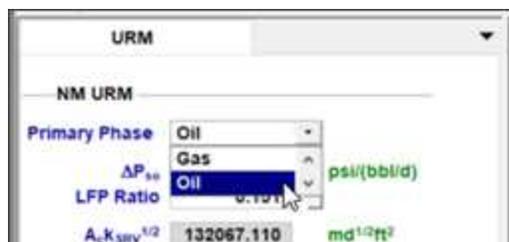


After smoothing:



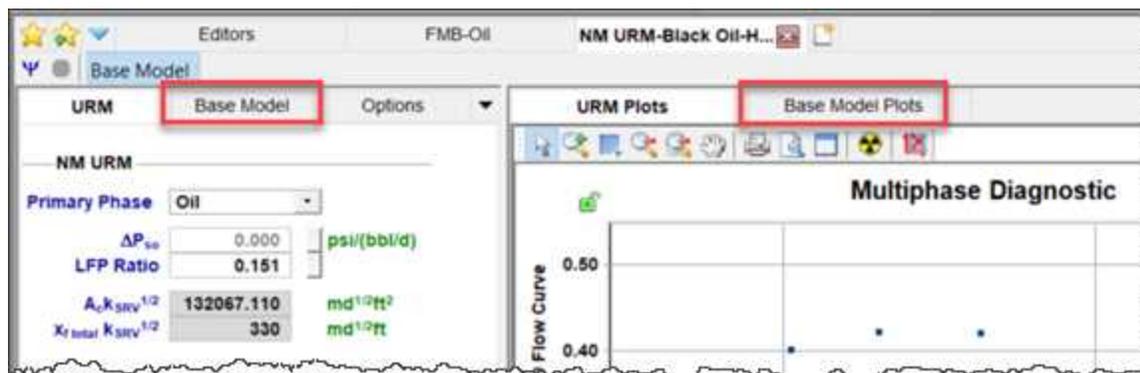
Other settings

Numerical URM defaults to a Primary Phase of Oil for Volatile Oil, Black Oil when there is oil production, and to a Primary of Phase of Gas for Gas Condensate. When there is no oil production for the Black Oil model, Harmony Enterprise sets the Primary Phase to Gas. You can switch the primary phase between oil and gas for black oil or volatile oil models. You can switch the primary phase between gas and condensate with the gas condensate model. The $OFIP_{SRV}$ below Match BD Flow and data on the plots is based on the Primary Phase selection.

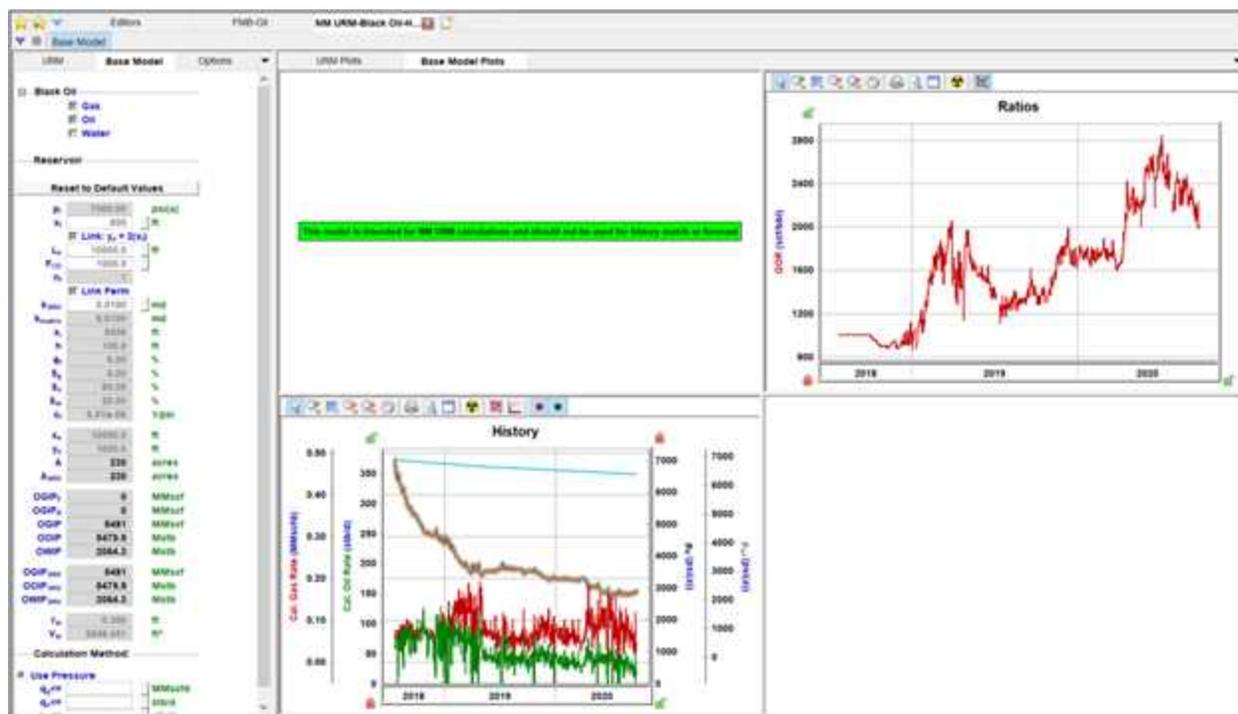


There are also options to enable the geomechanical and adsorption (for gas only) model options. These use the parameters specified in the [Properties editor](#).

If you want to view or modify the base model, it can be displayed by clicking the **Base Model** button in the toolbar, which displays a tab for the base model parameters and plots:



The base model primarily uses inputs from the Properties editor with a subset of inputs that you can modify. The Base Model Plots display the rates, ratios, and synthetic reservoir pressure from the base linear model.

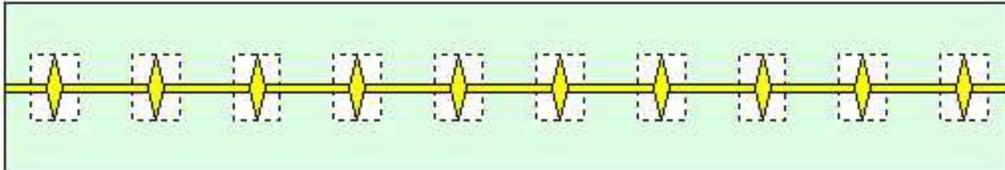


If you change base model inputs and want to revert to the default settings, click the **Reset to Default Values** button. The phases enabled in the base model are based on production data from the well.

In addition to the base model parameters, gridding for the model can be viewed or modified in the Options tab, which defaults to coarse gridding for faster performance. You can refine the gridding, but running the base model is slower.

Non-SRV cases

The numerical URM analysis is best-suited for analyzing wells that can be modeled using stimulated reservoir volume (SRV) geometry. However, if you believe that the well can be better described using enhanced-fracture-region (EFR) geometry (see image below), numerical URM analyses can still be useful.



Analyzing the linear portion of the flow for this case can be done in the same way as described above. You can:

- Estimate $A_c \sqrt{k}$
- Enter h , n_f , and x_f to find k (based on these entered parameters and estimated $A_c \sqrt{k}$)
- Enter h , n_f , and k to find x_f (based on these entered parameters and estimated $A_c \sqrt{k}$)
- Estimate t_{eIf} based on where the points start curving upward

However, matching the boundary-dominated portion of data cannot be done in the same way.

If data clearly indicates t_{eIf} , you can create a base boundary-dominated model with the same t_{eIf} to find the $OFIP_{SRV}$. However for this geometry, the "use $OFIP_{SRV}$ " option in the Breakdown for Parameters section should not be used as $A_{SRV} = 2x_f * L_e$ is not true for this case.

Note: In this case, we do not expect the boundary-dominated portion of data to match. This is because the horizontal multfrac model experiences true boundary-dominated flow, while the actual well experiences transition; there is no true boundary and some contribution from the matrix affects the behavior after the t_{eIf} .

Data Filter dialog box

This dialog box is commonly used when you click the filter data for an FMB, typecurve, numerical URM, or unconventional reservoir analysis.

This dialog box has the following important icons:

- **Tools to Select Data Points for Filtering**  — opens an additional toolbar with point-selection options.
 - **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.
 - **select all data points** — selects all the data points on the plot.
 - **deselect all data points** — deselects all the data points on the plot.
 - **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.
- **Fully Automatic**  — select one of these options:
 - **Median Filter** — used to make data less noisy by deselecting data points that are far from the rest of the data (those points are likely to be outliers). Note that the dataset needs to have at least 20 points for this filter to be applicable.

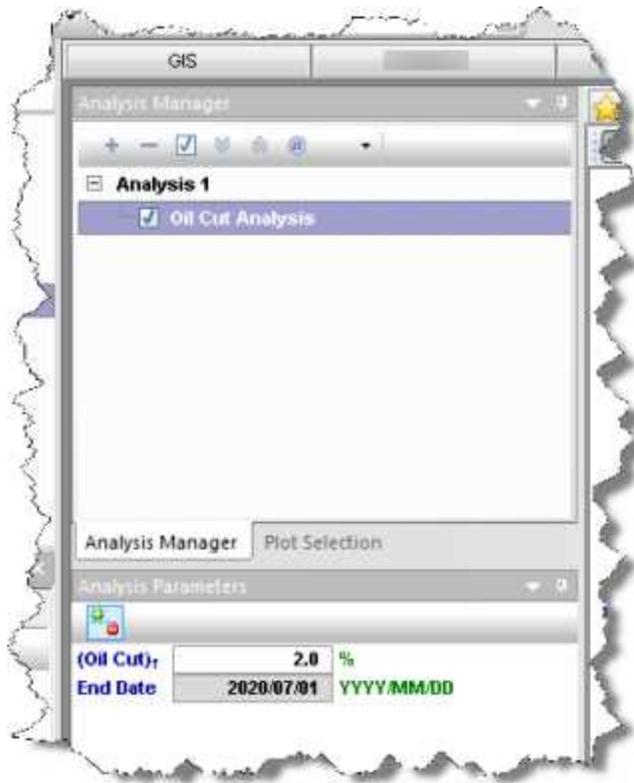
Oil cut analysis

The oil cut analysis is an empirical method for trending water and oil production. When an oil cut analysis is added, it is initialized using a best fit. Since time is on the x-axis, an EUR is not determined.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

An oil cut analysis can be added / displayed on an open worksheet while time is on the x-axis, and oil cut is on the y-axis. After you add an oil cut analysis (see [analyzing an entity](#)), the selected analysis has its detailed parameters displayed in the Analysis Parameters pane.



In this pane, you can specify / view the following parameters:

- **(Oil Cut)_f** — the final / abandonment oil cut. Initialized as 100-WC from the WC value defined in the Options dialog box (under the Water Oil Ratio node). The value must be in the range (0, 100).
- **End Date** — the corresponding date at the oil cut abandonment value.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following icon:

-  **Show / Hide Results Line** — shows (default setting) or hides the dashed-green line on the plot that represents the abandonment for the oil cut analysis. It is initialized from the settings defined in the Options dialog box, under the Water Oil Ratio node.

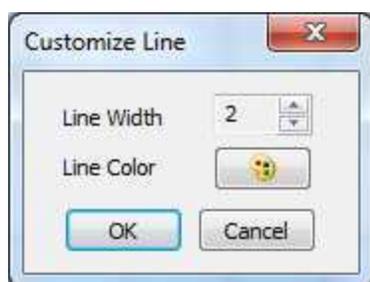
Line manipulation

Line manipulations are initiated by clicking-and-dragging:

- **Line** — changes the slope of the trend line about the manipulation point.
- **Manipulation point** () — translates the line vertically or horizontally while maintaining the slope.

Analysis line customization

You can customize your analysis line's width and color by right-clicking and selecting **Customize Line**.



Your modifications are saved and applied to every worksheet that displays this analysis.

Oil IPR / TPC

An oil IPR / TPC analysis provides options to calculate and display the maximum oil rate and inflow performance relationship (IPR) for an oil well. It also provides the ability to create tubing performance curves (TPCs), which can be used to determine the expected operating point (intersection of the IPR and TPC curves) of a particular reservoir / wellbore combination. The intersection of the IPR curve with a TPC signifies the operating point of the particular wellbore / reservoir combination. For reference material, see [Oil IPR / TPC theory](#).

Note: This analysis works with your Harmony Optimize™ license.

This analysis has the following icons in the Inflow and Outflow panes:

-  **Delete** — removes the currently selected inflow, outflow, gradient, or forecast.
-  **Copy** — creates a duplicate of the currently selected inflow, outflow, gradient, or forecast. The name is appended with the word "Copy".
-  /  **Show / Hide** — toggle between showing or hiding the inflow, outflow, gradient, or forecast.

-  /  **Collapse / Expand** — closes / opens the details for the inflow, outflow, gradient, or forecast. If you see a red triangle () in the top left of a collapsed analysis, you need to investigate the required parameters.

Inflow pane

The Inflow pane on the left-side has the following items:

- **Inflow** — click the **Add Inflow** button to create an inflow that is measured at the sandface.
 - **Vogel** — the Vogel equation is a widely accepted method for determining a reservoir's deliverability IPR. The calculation uses your information to determine the well's IPR at the sandface. This relationship between pressure and rate can be used to visually determine the desired operating pressure, or it can be combined with TPCs to compare well performance scenarios
 - **Custom Table** — used to test points in tabular form to generate a reservoir IPR curve without being restricted to a single model. This inflow currently supports Vogel-based or Fetkovich-based curves, as well as a pure linear interpolation of input points.
- **Configuration** drop-down list — select the wellbore configuration or optimize configuration you want to use when converting from wellhead to sandface pressure. For more information, see [optimize configurations](#).

Note: Your bubble point pressure is automatically imported from the [Properties editor](#).

Plot

The plot in the center of the window has the following items:

- **Plot** — the plot is displayed after you type all the required parameters. Intersections on the plot correspond to the points in the Operating Points table. The axes operate in the same manner as [Economics](#). For more information, see [Y-axis icons](#) and [X-axis icons](#). To rescale the plot back to its original settings, double-click it.
 - **Auto-scale to fit all** checkbox — fits the plot to the maximum viewable area of the screen.

- **Show Sensitivities** checkbox — displays sensitized / transient inflows in the plot with a light-blue line, as well as inflows in the key-performance-indicators table below.
- **Show all valve curves** checkbox — displays the outflow for every valve depth entered in the Optimize Configuration (only applies to the artificial lift outflow). If deselected, the deepest valve depth that calculates a valid operating point is used to display the outflow curve.
- **Operating Points** tab — displays a table with operating points (inflow over TPC) for a baseline, and sensitivities A, B, and C.
- **Inflow Comparisons** tab — displays a plot of all inflows.

Outflow pane

The Outflow pane on the right-side has the following items:

- **Pair all with** drop-down list — matches all TPCs to one inflow.
- **Outflow** — click the **Add Outflow** button to create a TPC. Type values or select from drop-down lists for fields in white. Gray fields are read-only. Note that all TPCs require a parent inflow and a wellbore. By default, the TPC pairs with the active inflow.
- **Configuration** drop-down list — by default, the most-recent configuration is selected. If there is a red box around the Configuration drop-down list, you need to make corrections in the Wellbore editor.
- **Add / Edit** link — opens the Wellbore Editor popup where you can create, delete, and edit Optimize Configurations without leaving the worksheet.
- **Wellhead FP** field — type your wellhead flowing pressure.
- **Liquid Ratios** section — select from the drop-down list, so you can type values for your ratios.
- **Separator Efficiency** — only available when your selected Optimize Configuration has its flow path set to **Pumping**. This input controls the percentage of free gas found at pump intake conditions which are expelled up the annulus of the well. This expelled gas is omitted from Outflow curve calculations.
- **Gas Lift** inputs — only available when your selected configuration has its flow path set to **Gas Lift - Tubular** or **Gas Lift - Annular**.
 - **Reservoir Liquid Ratios** — converted from the Liquid Ratios section for Gas Lift Outflows. These inputs indicate the producing fluid ratios excluding gas lift injection volumes.

Injection Pressure — type your injection-side flowing pressure. This is in the opposite direction of the flow path.

- **Injection Gas Rate** — type your intended gas lift injection rate.
- **Injected Gas Gravity** — displays the specific gravity of the injected gas. To edit this value, navigate to **Editors, Properties, Gas Lift**.
- **Choke Calculator** section — for quick calculations of critical (sonic) flow conditions across a given choke diameter. You can run a wide variety of sensitivities on pressures, temperatures, and fluid properties.

For more information on multiphase-flow choke correlation limits, see [references](#).

For a given set of conditions, a TPC is a plot of the flowing sandface pressure, as a function of flow rate. This curve does not change through the life of the well. It is not at all dependent upon reservoir performance; it depends only upon the gas-liquid ratio, tubular configuration (depth, diameter), wellhead pressures, etc.

Chokes

The choke calculator is a simple and effective tool for calculating sonic-flow characteristics of your well for both single-phase gas and multiphase fluids. The calculator can be used to determine the upstream or downstream pressure across your choke. It can also be used to find the temperature drop across the choke using the Joule-Thomson cooling correlation. The sonic gas rate is displayed at the bottom of the choke calculator.

Note: The choke calculator does *not* currently impact TPC calculations.

The choke calculator supports the following correlations:

- Ashford-Pierce (multiphase analytical)
- Achong, Baxendell, Gilbert, Ros (multiphase empirical)

Operating Points table

The Operating Points table at the bottom of the window has the following items:

- **Baseline** tab — your baseline key performance indicators (KPIs) are displayed over the TPC.
- **A** tab — your "A" sensitized / future inflow's KPIs are displayed over the TPC.

- **B** tab — your "B" sensitized / future inflow's KPIs are displayed over the TPC.
- **C** tab — your "C" sensitized / future inflow's KPIs are displayed over the TPC.

Tip: You can view your sensitivities if the **Show Sensitivities** checkbox is selected at the top of the window.

Note that you can view your H₂S rates for each of the operating points under the following conditions: the H₂S% in the Editors tab must be greater than 0%, and Oil TPCs must have a non-zero gas-oil ratio. If you type a GOR value in the Outflow pane, an H₂S rate is displayed as a function of the operating-point rate. If two TPCs are paired to one inflow, both TPCs are identical, except a GOR is not used for one of the TPCs. While the H₂S column is displayed in the Operating Points table, only one of the rows has an H₂S rate that is calculated.

Vogel inflow

By using the Vogel inflow, you can estimate a well's inflow performance relationship (IPR) by entering:

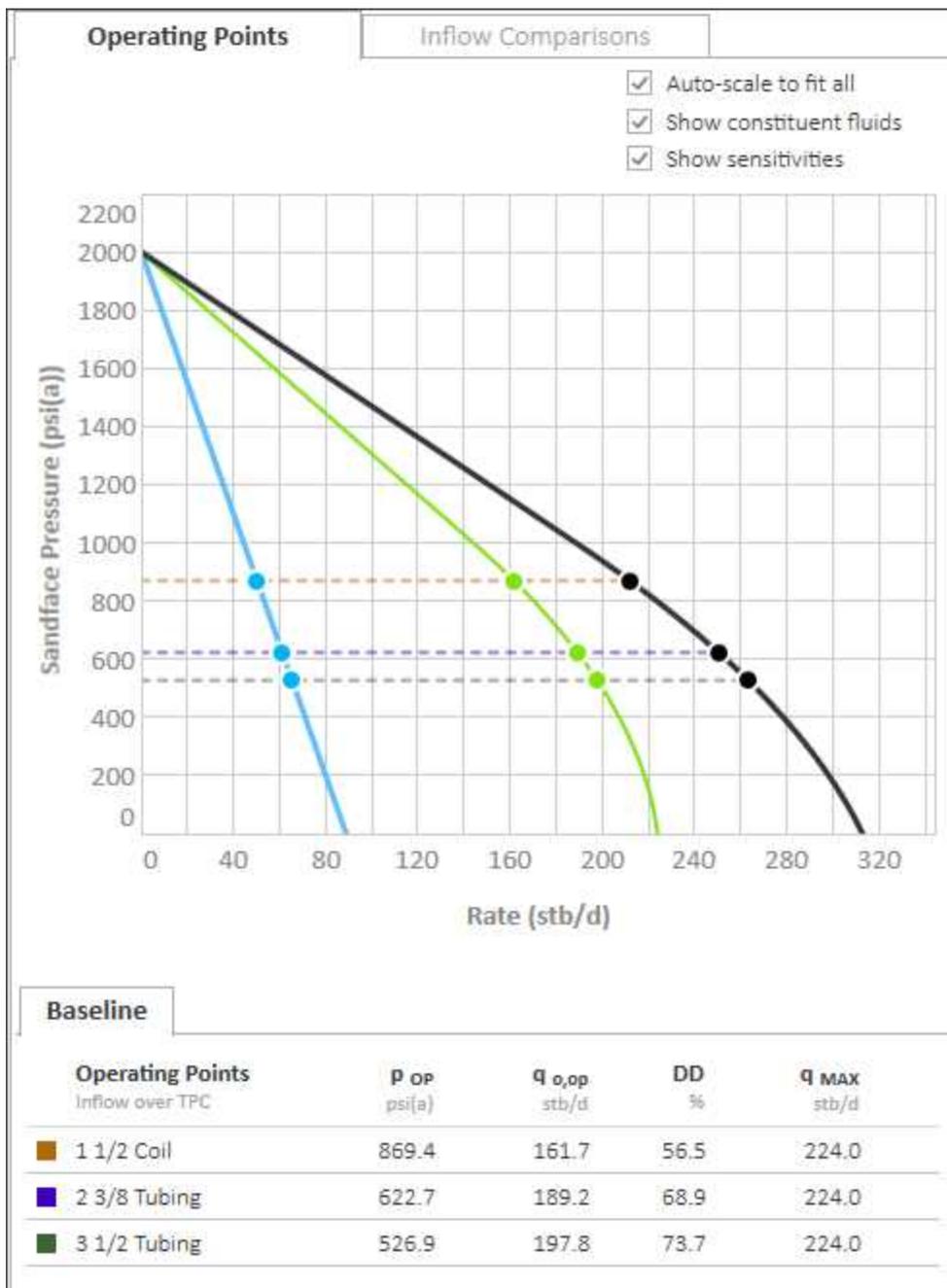
- Reservoir pressure
- Test data (measured rate at a specified sandface pressure)

Note: Oil bubble point pressure is also required, and this must be entered in the Properties editor.

Liquid Composite

Optionally, you can select the Liquid Composite method. After entering the water rate (or ratio), the IPR is recalculated as three curves:

- Oil curve
- Water curve
- Total liquid (oil + water) curve



Furthermore, any TPC is converted to a horizontal line of constant sandface pressure. This sandface pressure is the same as the operating point pressure. Consequently, the operating rates for water, oil, and total liquid are displayed on the plot.

Future inflows

Optionally, you can enter up to three additional reservoir pressures. By doing so, the productivity index from the baseline IPR is used with the entered reservoir pressure to calculate a future IPR.

Custom table inflow (oil)

With the oil custom table, type your reservoir pressure or paste from Excel, and then select your fit type:

- **Vogel** — is a widely accepted inflow correlation for oil wells above and below the bubble point pressure. It requires a minimum of one input point in the custom table to create an inflow curve.
- **Fetkovich** — is a commonly used inflow correlation for oil wells. It requires a minimum of two points in the custom table to create an inflow curve.
- **Linear** — is a straight-line interpolation between test points. It requires a minimum of one input point in the custom table to create an inflow curve. Unlike other fit types, it does not extrapolate to absolute open flow (AOF).

The Custom Table uses your input test points consisting of a stabilized production rate and a sandface flowing pressure, and then plots an inflow performance relationship (IPR). After you have typed test points, they can be selected or deselected in the Plot column. If the Plot checkbox is deselected, that point is omitted from inflow calculations, and is not displayed on the plot.

If you have an error in the Custom Table, an error indicator is displayed along with a tooltip.

Examples of error messages are as follows:

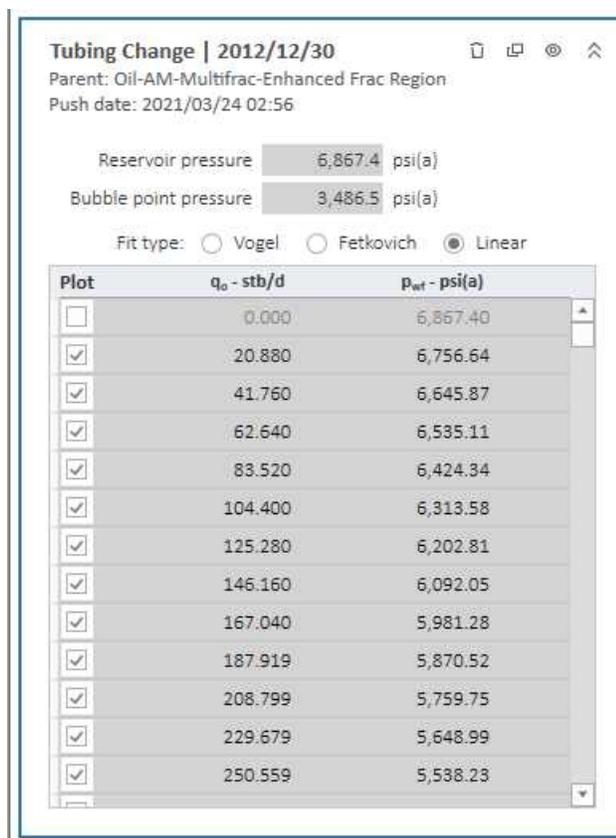
- **q <= 0** — the production rate must be greater than zero.
- **>p_R** — the sandface pressure must be less than the reservoir pressure.
- **<p_{atm}** — the sandface pressure must be greater than average atmospheric pressure (14.7 psia or 101.3 kPaa).
- **Dupl.** — if two data points exist that use the same oil rate, then the Custom Table only uses the point with the higher sandface pressure for inflow calculations, so long as this higher point does not trigger any other error messages.

Future inflows: You can extrapolate your reservoir deliverability curve to the future. Based on your Custom Table inflow curve, you can generate sensitivities for your operating points to varying reservoir pressures (not available for the Linear fit type).

Imported IPRs (from Advanced Forecast)

From Advanced Forecast, you can push an IPR to an IPR / TPC worksheet.

After a curve is pushed from the Advanced Forecast worksheet, it becomes a read-only analysis in the IPR / TPC worksheet. There is no synchronization between the imported forecast and the source Advanced Forecast analysis.



The analysis name is set to "<Forecast Name> | <Forecast Date>", and is read-only. Below the analysis name are two sub-headers: the first is the name of the parent analytical model; the second is the push date. This date is the date and time at which the inflow curve was sent from the Advanced Forecast worksheet. This is a means of version control in case changes have been made to the Advanced Forecast or the parent analytical model.

The custom table is populated with a read-only array of rates and flowing pressures corresponding to the IPR from the Advanced Forecast. All data points are pulled across, with any invalid points being deselected.

Note: If you want to edit the IPR, click the **Copy** icon () to create an editable copy.

Imported TPCs (from Advanced Forecast)

A pushed TPC is similar to that of a pushed IPR. The analysis name is set to “<Forecast Name> | <Forecast Date> | Outflow”. This read-only pane includes additional information regarding the parent analytical model and push date.

The Parent Inflow selection remains editable so you can pair your pushed Outflow to any Inflow analysis panes on the same worksheet.

The wellbore configuration selection, flowing pressure, and wellbore dimensions are read-only and reflective of the wellbore conditions at the specified forecast step.

If secondary fluid ratios are specified in the Advanced Forecast, these are reflected in the Liquid Ratios section at the bottom of the Outflow pane.



Tubing Change | 2012/12/30 | Outflow    

Paired to Tubing Change | 2012/12/30
Parent: Oil-AM-Multifrac-Enhanced Frac Region
Push date: 2021/03/24 02:56

Parent inflow: Tubing Change | 2012/12/30

Configuration: Casing

Wellhead FP: 3,000.00 psi(a)

Casing Dimensions

Inner diameter: 4.670 in

Roughness: 0.000600 in

Customize Flow Path and Tubing

Tubing Annulus Both Casing

Bottom depth (MD): ft

Outer diameter: in

Inner diameter: in

Roughness: in

Liquid Ratios

Gas:Oil: scf/bbl

Water:Oil: bbl/stb

Note: If you want to edit the TPC, click the **Copy** icon () to create an editable copy.

Artificial lift outflow

With your Harmony Optimize license, you can have analyses with gas lift and pumping flow paths. First you need to create an Optimize Configuration in the Wellbore editor. In the Pressure Loss Calculation Parameters section, update the flow path to **Gas Lift - Tubular**, **Gas Lift - Annular**, or **Pumping**.

Gas lift

After selecting a gas lift configuration, the Outflow pane on the right-side adds a **Gas Lift Injection** section, which requires the following additional inputs:

- Injection Pressure
- Injection Gas Rate
- Injected Gas Gravity (this value defaults to the value entered in the Properties editor)

For information on valve depths, see show all valve curves.

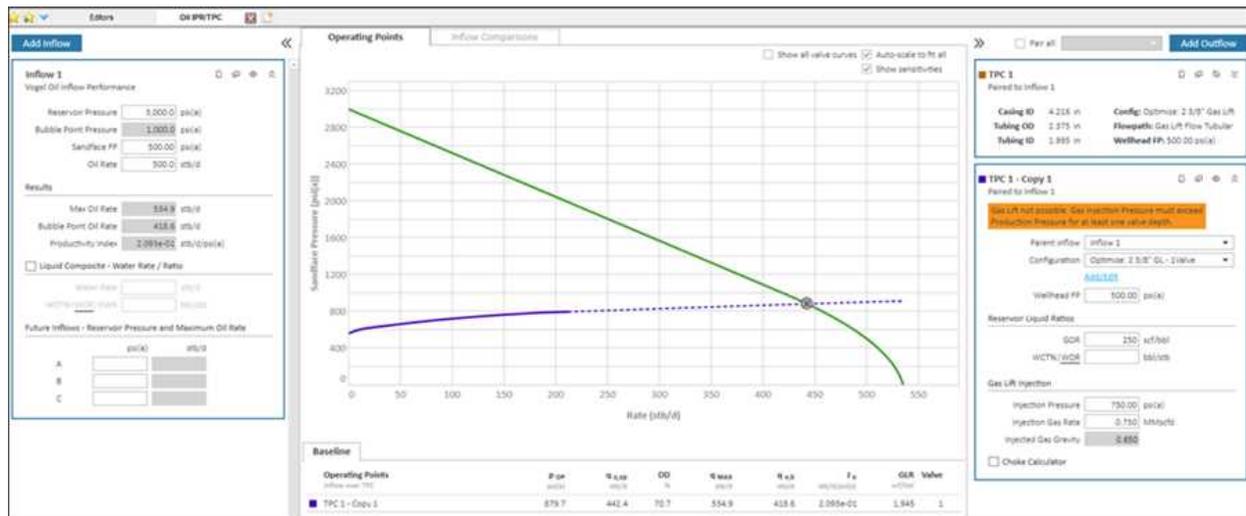
Plot and operating points

The operating points on the plot are displayed in one of the following colors:

- **Green** — the operating point is in the preferred range.
- **Black "X"** — the operating point is invalid (gas lift is not possible).

Example

In this screenshot, gas lift is not possible. This is denoted by orange highlighted text in the Outflow pane and an X icon for the operating point on the plot. Furthermore, the performance curve is displayed with a long dashed-line segment, which indicates that the producing rate is too high for gas lift to be possible.



To fix the problem, you may need to:

- change the injection pressure.
- change the injection rate.
- change the wellbore settings in the Optimize Configuration, such as the valve depth.

In this screenshot, the gas lift outflow curve is operating in the preferred range. The warning message is gone and the operating point icon is in its normal state.



Electrical submersible pump (ESP)

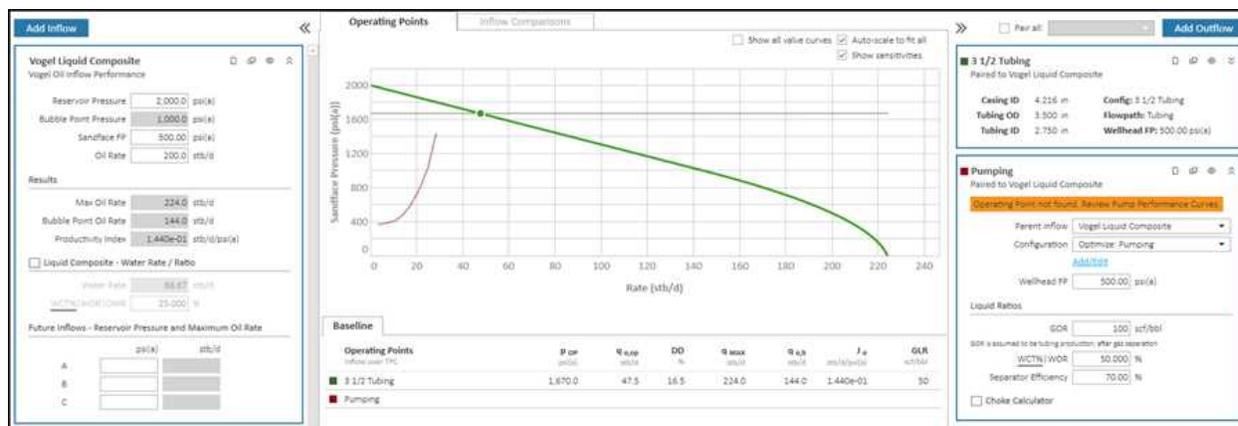
Note: For ESP analysis, you must select an Optimize Configuration with the flow path set to **Pumping**. For more information, see [Wellbore editor](#).

After selecting the pumping configuration, the Outflow pane on the right-side requires one additional input called Separator Efficiency.

- The separator efficiency reflects the percentage of free gas at pump conditions removed from the pump flow path (and produced up the annulus).
- GOR input is assumed to be the tubing production after gas separation.
- If over 20% of the total fluid volume is free gas at pump intake conditions, ESPs can be damaged. Calculations continue, but a warning message is displayed.

Example

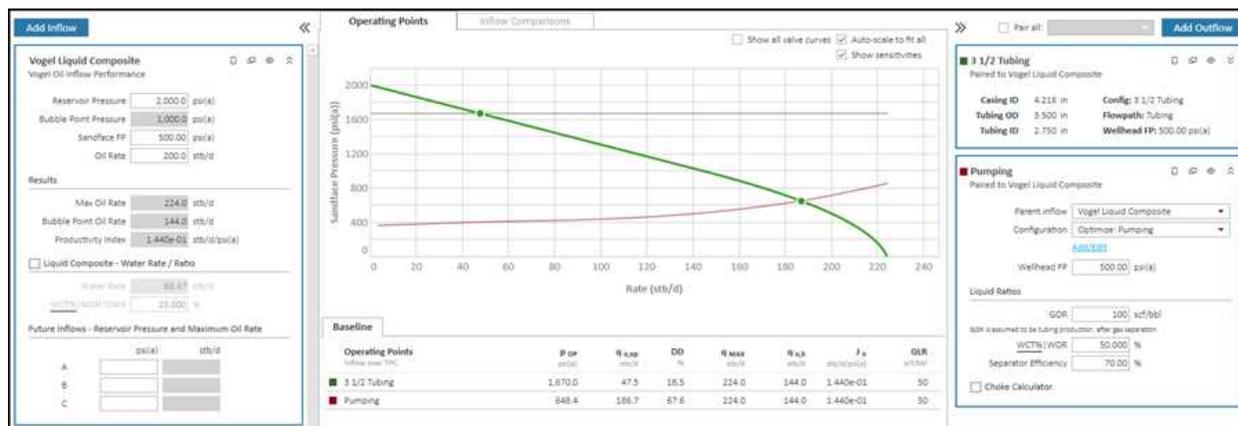
In this screenshot, pumping is not possible. This is denoted by orange highlighted text in the Outflow pane and no valid operating point on the plot. Furthermore, the performance curve appears to stop at a rate of 30 bbl/d – well below an expected rate given the inflow curve for this well.



To fix the problem, you may need to:

- Check that you have correctly entered the range of rates for the pump.
- Investigate total fluid rate (oil, water, and free gas) to ensure that the pump is correctly sized.

In this screenshot, the pumping outflow curve is operating in the preferred range. The warning message is gone and the operating point icon is in its normal state.



Probabilistic decline analysis (beta)

This analysis provides decline forecasts for the input percentiles based on distributions of q_i and b . For information on this methodology, see [probabilistic decline method](#).

Harmony Enterprise has a default set of P90, P50, and P10, but you can set any percentile values in the [Options dialog box](#) and have between two and ten analyses created. The naming of analyses, b range, d_{lim} , and abandonment criteria can also be customized in the Options dialog box.

We strongly recommend tailoring the b range to the reservoir and fluid when applying the probabilistic decline. The default range of 0 to 2 is most appropriate for newer wells with a short production history.

After the analyses are created (see [analyzing an entity](#)), they function similarly to a [traditional decline analysis](#) including line manipulations, exports, use in economics, etc. Analyses are created with distinct line colors, but these colors can be modified on the plot. The default colors are set for the P1 - P35, P36 - P65, and P66 - P99 ranges. Note that if you create two percentiles in the same range, they are displayed in the same default color. Point selection for best fitting and fitting the decline to a forecast are disabled for the Probabilistic Decline because these features use standard best-fitting and are more appropriate for use on a traditional decline analysis.

Note: This analysis works with your Harmony Forecast™ license.

The Probabilistic decline analysis provides an initialization in order to create a range of forecasts for a given well. After the analyses are created, they behave as a traditional decline and do not retain information about the forecast distribution that was used to create them.

Analysis Manager pane

In the Analysis Manager pane, click the **Add an analysis** icon () and select **Probabilistic Decline (Beta)**.

The decline analyses for your specified percentiles are created and each decline has its detailed parameters displayed in the Analysis Parameters pane located below the Analysis Manager pane (the default setting). These decline analyses can be linked to other analyses, renamed, and modified.

Plot Selection pane

Additional datasets can be displayed using the list in this pane. This can allow for other types of analyses to be displayed simultaneously. You can also hide any of the currently displayed datasets, though this can result in some analyses no longer displaying on the plot.

Note: When you save a workflow, these customizations are included.

Analysis Parameters pane

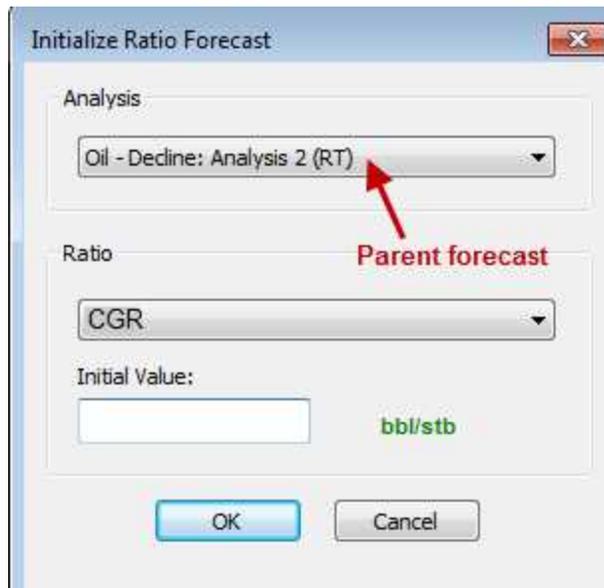
For more information, see the decline analysis.

Ratio forecast

Ratio forecasts are used to apply a user-input ratio to an existing forecast in order to calculate another fluid's forecast. As a prerequisite, you must have an existing forecast, and you can only add ratio forecasts to analyses that are forecasts.

Note: This forecast works with your Harmony Forecast™ license.

After you open your existing forecast, you can add a ratio forecast (see analyzing an entity) and initialize this forecast using a constant ratio value.



The ratio forecast is a child forecast, so if you update, move, or delete the parent forecast, the child is updated automatically. Note that the child forecast does not affect the parent.

Changes from the constant value ratio can be made by typing or pasting the ratio column of the Forecast worksheet.

The initial value for the ratio forecast can be updated, but the duration is set by the parent forecast (for example, the decline). If you extend the range of the parent forecast, the ratio forecast automatically extends its initial value to match the new end date. If you truncate the range of the parent forecast, the unnecessary rows in the ratio forecast are automatically deleted.

You can change your table resolution by clicking the **D** (day), **M** (month, the default setting), or **Y** (year) icons on the toolbar. For a description of common icons, see [toolbars](#).

Ratio trend

The ratio trend is used to create linear forecasts of fluid ratios vs time. These can be linked to decline analyses to create rate forecasts in place of analyzing secondary fluids independently. The ratio trend is not based on a model or equation, and you should consider the fluid properties of a reservoir in order to constrain forecasts.

The supported ratios include gas-oil ratio (GOR), water-oil ratio (WOR), condensate-gas ratio (CGR), and water-gas ratio (WGR). On a worksheet that includes one of these ratios plotted

against date time or cumulative time, the corresponding ratio trend is available to add in the Analysis Manager by clicking the + icon.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

After you add your ratio trend, the selected analysis (highlighted in gray) has its detailed parameters displayed in the Analysis Parameters pane located below the Analysis Manager pane. (This is the default setting.)

The screenshot shows the 'Analysis Manager' window with a tree view on the left containing 'Exponential RC', 'Exponential RT', and 'Analysis 1' (with 'GOR Ratio Trend' checked). The main area has tabs for 'Analysis Manager' and 'Plot Selection'. Below is the 'Analysis Parameters' section, which includes a 'Ratio Axis Type' dropdown set to 'Log'. Two segments are defined:

Segment 1		
Manipulation Method	Variable Ra...	
Start Date	03/26/2001	MM/DD/YY
End Date	10/29/2022	MM/DD/YY
Δt	259.1	month
GOR _i	329.7	scf/bbl
GOR _f	480.8	scf/bbl
GOR/Time Slope	632.2	scf/bbl/n

Segment 2		
<input checked="" type="checkbox"/> Lock To Previous Segment		
Manipulation Method	Constant R...	
Start Date	10/29/2022	MM/DD/YY
End Date	04/22/2045	MM/DD/YY
Δt	269.8	month
GOR	480.8	scf/bbl

Harmony Enterprise initially best fits your ratio trend based on all the production history of the ratio.

In this pane, you can view the following setting:

Ratio Axis Type —displays Log or Coordinate, depending on the axis type you set for the ratio on the worksheet when you created the ratio trend. The ratio trend can be

displayed and manipulated on the other axis type, but it cannot be changed to the other axis type. It does not appear as a straight line when the axis display is switched, as it is linear only on the axis type it is created on.

Multiple segments

You can add multiple segments (see [Analysis Parameters toolbar](#)) to your ratio trend, and under each segment, you can change parameters and the manipulation method for that segment.

Under each segment's tab, you can specify / view the following parameters:

- **Manipulation Method** — select Variable Ratio for linearly increasing or decreasing ratios, and select Constant Ratio for a fixed value. The default settings is Variable Ratio.
- **Start Date** — the start of the ratio trend is indicated by a left square on the analysis line.
- **End Date** — the end of the ratio trend is indicated by a right square on the analysis line.
- **Δt** — the duration of the ratio trend from the start date to the end date.
- **Initial Ratio** — the initial ratio value at the start of the ratio trend. This is displayed as a ratio acronym (such as GOR) with the subscript 'i' and is only applicable to the Variable Ratio.
- **Final Ratio** — the final ratio value at the end of the ratio trend. This is displayed as a ratio acronym (such as GOR) with the subscript 'f' and is only applicable to the Variable Ratio.
- **Slope** — for the Variable Ratio trend, this is the difference between the final and initial ratio divided by the duration.
- **Ratio** — a Constant Ratio trend shows the ratio value used over its duration with a ratio acronym (such as GOR).
- **Lock To Previous Segment** — on secondary segments, when this option is on the initial ratio, it is locked to the final ratio of the previous segment, and both remain synchronized through any analysis modifications.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following key icons

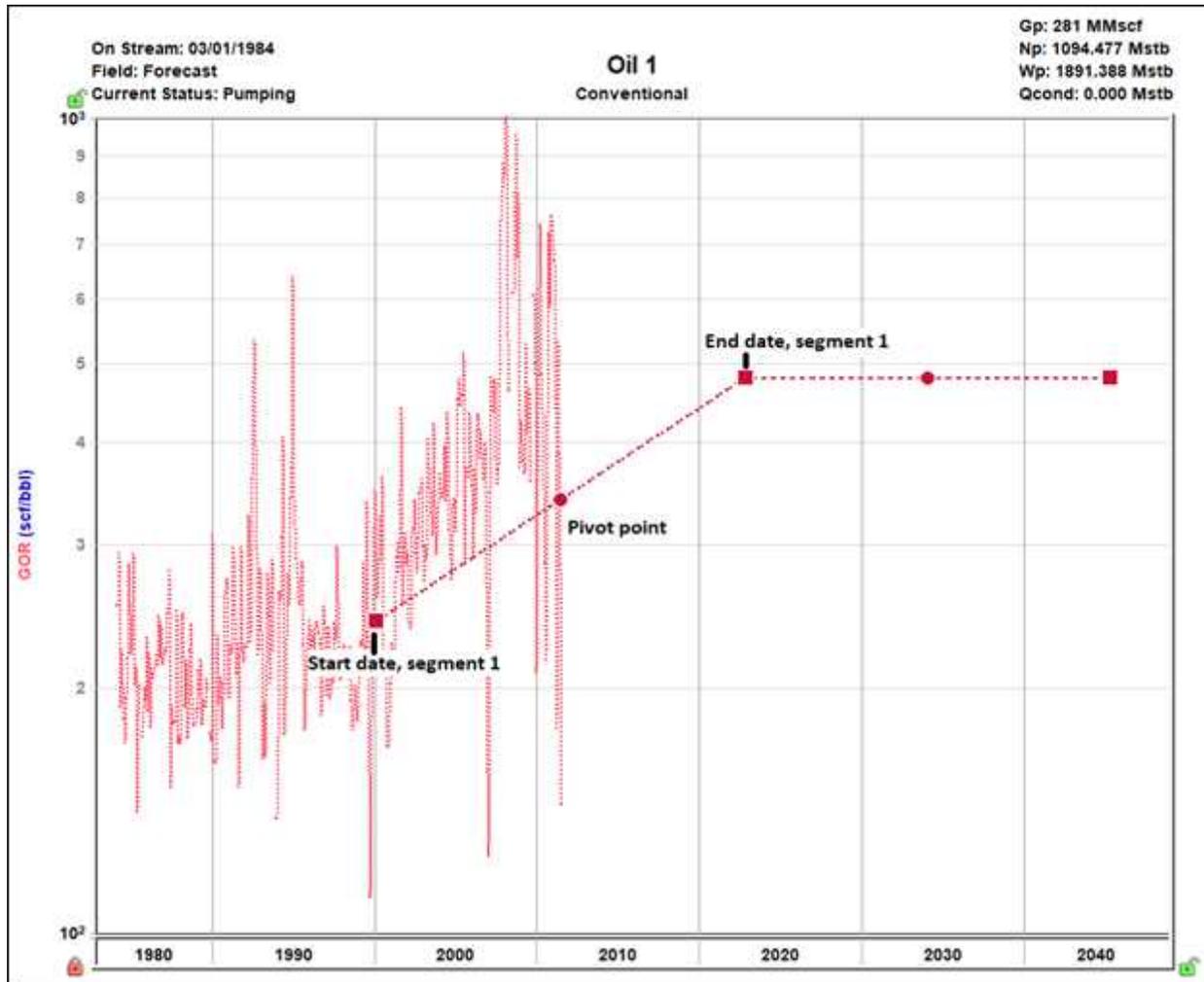


Add Segment / Remove Segment — adds a new segment to the end of the existing ratio trend, or removes the last segment. When you add a new segment, it

initializes as a Variable Ratio with the same starting value and slope of the previous segment. The duration of new segments is 60 months (5 years).

Line manipulation

Line manipulations are initiated by clicking the line itself, or one of the manipulation points for a given segment (start date or end date). Specific line manipulations are described below.



Start Date (indicated by a left square)

- **Click, grab-and-drag** — moves the line vertically and horizontally (4-direction pan) to change the start date and the initial ratio. The slope is changed, but the end-date point stays fixed.
 - On a Constant Ratio segment, this only moves horizontally and changes the start date.

End Date (indicated by a right square)

- **Click, grab-and-drag** — moves the line vertically and horizontally (4-direction pan) to change the end date and the final ratio. The slope is changed, but the start-date point stays fixed.
 - On a Constant Ratio segment, this only moves horizontally and changes the end date.

Any point on the line (activated when the segment turns orange)

- **Click, grab-and-drag** — rotates the line about the pivot point. Both initial and final ratios are changed, but the start and end dates are fixed. This is not available for Constant Ratio segments.

Pivot point (indicated by a circle)

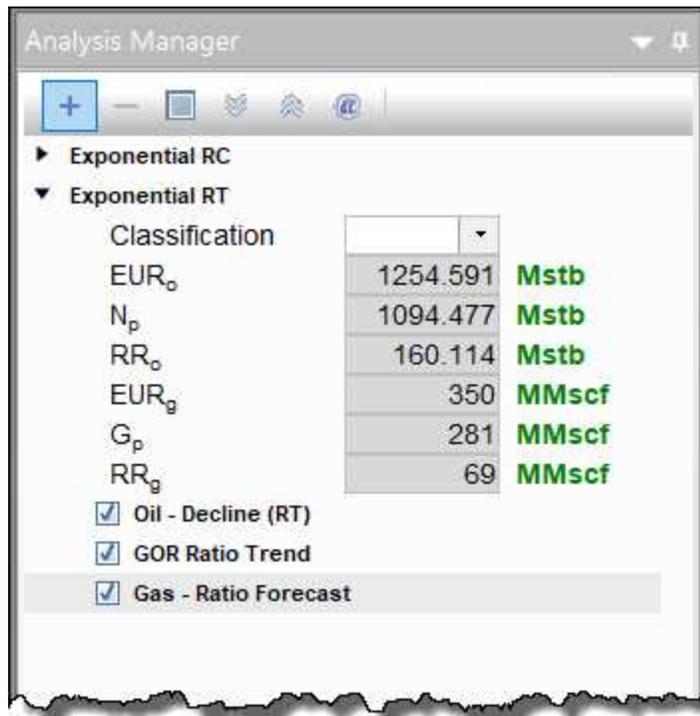
- **Click, grab-and-drag** — moves the line vertically while the slope is maintained. The pivot point can also move along the line to change its position.

Linking to a Decline analysis

After you have created a Ratio Trend, you can link it to a decline analysis to calculate a rate forecast. For example, linking a GOR and oil decline calculates a gas rate forecast. This can be done by clicking the ... button next to the analysis in the Analysis Manager. For more information, see [Analysis type menu](#).

For each ratio, either fluid can be linked to calculate the other, but only traditional and multi-segment declines are used. Duong, Stretched Exponential, and other forecast types do not generate a rate forecast with a ratio trend. The rate forecast is calculated from the decline's Forecast Start Date to End date. If the Ratio Trend does not extend over the same duration, a fixed value of the ratio is extrapolated to fill the gap.

The calculated rate appears as an item in the Analysis Manager (selected below) that can be displayed on a worksheet with its rate, or on the Forecast worksheet.



If the decline or ratio trend is removed from the parent analysis or deleted, the rate forecast is deleted. Another analysis that generates a rate forecast of the same fluid type cannot be linked to the analysis after the rate forecast is created.

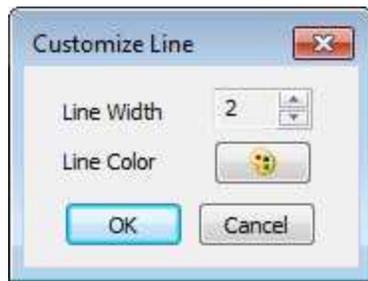
The rate forecast can be exported. For more information, see [export forecasts](#). When the ratio trend is linked to an appropriate decline, it can also be exported to ARIES. For more information, see [export decline parameters](#).

An ARIES export supports the following combinations:

- GOR + oil decline
- GOR + gas decline (exported as OGR)
- WOR + oil decline
- CGR + gas decline
- WGR + gas decline

Analysis-line customization

You can customize the width and color of your decline line / curve by right-clicking it.



After you customize your decline line / curve, the modifications are saved and applied to every worksheet that displays this decline.

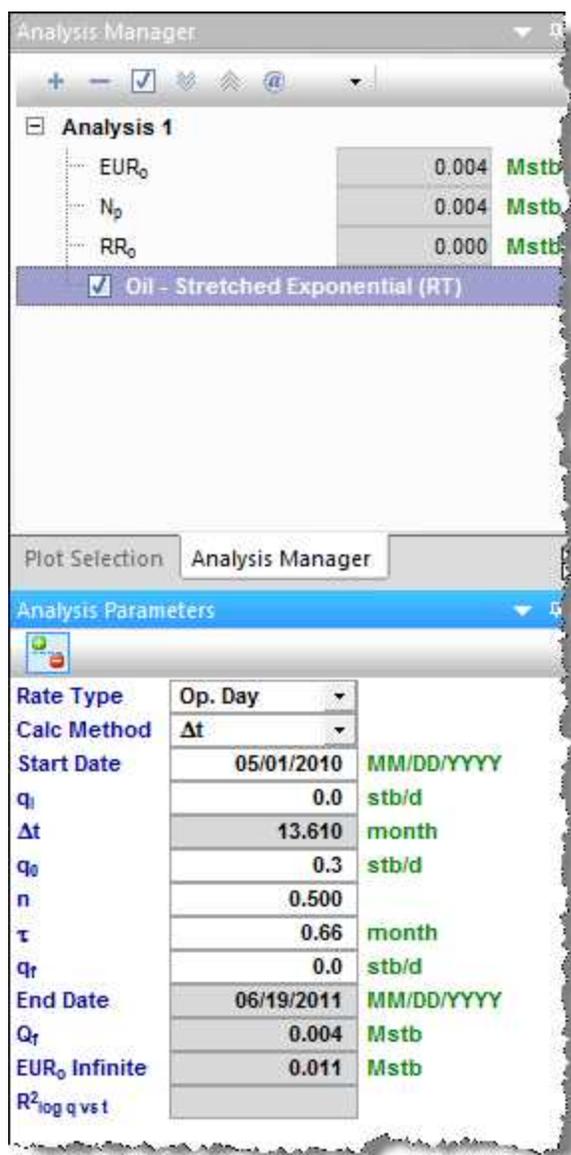
Stretched exponential decline analysis

The stretched exponential decline method is a variation of the [traditional Arps method](#), but is better suited for unconventional reservoirs due to its bounded nature. For more information, see [stretched exponential decline theory](#).

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

After you add your decline analysis (see [analyzing an entity](#)), the selected analysis (highlighted in purple) has its detailed parameters displayed in the Analysis Parameters pane located below the Analysis Manager pane (the default setting).



In this pane, you can specify / view the following settings and parameters:

(The parameters that are displayed depend on if the analysis was created on a rate-time (RT) or rate-cumulative (RC) production plot.)

- **Rate Type** — select calendar rate (**Cal. Day**) or operator rate (**Op. Day**) from the drop-down list. For more information, see [decline analysis: rate type](#).
- **Calc Method** — select the method by which the decline analysis is calculated (for example, Δt or q_r) from the drop-down list.

- **Start Date** — the end of production data and the date of the forecast start, represented by the middle point of the analysis line.
- q_i — the initial gas / oil production rate for the forecast.
- Q_i — the cumulative production at the start of the forecast.
- Δt — the duration of the decline segment.
- q_o — a stretched exponential q_o term. (The initial rate at the start of production. Not to be confused with q_i , which is the initial rate at the start of the forecast.)
- n — a stretched exponential n term; it must be between 0 and 1.
- τ — a stretched exponential t term; it must be positive.
- q_f — the gas / oil production rate at the end of the forecast.
- **End Date** — the date the forecast ends.
- ΔQ — the cumulative production that occurs during the forecast period.
- Q_f — the cumulative production at the end of the forecast — expected ultimate recovery (EUR).
- **EUR₀ Infinite** — the EUR if the abandonment rate = 0.
- **R²** — an indication of the precision of the history match. It is reported as $R^2_{\log q \text{ vs } t}$ on a rate-time (RT) plot, and $R^2_{2q \text{ vs } Q}$ on a rate-cumulative (RC) production plot.

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following icon:



Show / Hide Results Line — shows (default setting) or hides the dashed-green line on the plot that represents the abandonment for the stretched decline analysis..

Line manipulation

Line manipulations are initiated by clicking (sometimes while pressing the **Ctrl** or **Shift** keys) the line itself, or one of the manipulation points for a given segment (start date, forecast start date, or end date). You can cancel your line manipulation by pressing the **Esc** key. Specific line manipulations are described below:

Tip: Any time you see "click", this means to left-click your mouse. Right-click actions are specifically mentioned.

- **Start Date** (indicated by a blue circle)
 - **Click, grab-and-drag** — moves the decline line vertically to change the q_i of the segment. However, it does not change the *start date* or *Forecast Start Date (FSD)*. The shape of the decline (b and d) line is preserved.
 - Both q_i and q for the segment being manipulated get modified, and all segments following this segment are shifted in time / cumulative production, accordingly.
 - **Shift key** — pressing the **Shift** key while dragging extends your forecast back into the historical production. The *start date*, q_i , and d_i change, but the b value is not impacted.
 - This Shift-key functionality does not apply to a *secondary* segment.
 - **Ctrl key** — pressing the **Ctrl** key while dragging translates the curve along the x-axis. The *start date*, *FSD*, and *forecast end date* advance in time for the first segment.
 - This Ctrl-key functionality does not apply to a *secondary* segment.
- **End Date** (indicated by a blue square)
 - **Click, grab-and-drag** — enables you to move the *end date* in time, anchoring to the start date and maintaining the q_f . The b value is maintained, but d_i is updated. If the FSD is contained within the segment, then q and d update as well.
 - **Shift key** — pressing the **Shift** key while dragging extends your forecast forward in time, and decreases your final rate (q_f). Your final Q_f increases, but none of the decline parameters change.
 - **Ctrl key** — visually similar to the grab-and-drag functionality for the end date, but the b value can change with the Ctrl-key functionality.
- **Any point on the forecast decline curve** (activated when the decline segment turns orange)
 - **Click, grab-and-drag** — If the segment contains the FSD, that segment is anchored to the *FSD* and rotates around while the b value and q_f are maintained.
 - On a segment that does not contain FSD, the decline is anchored to the *start date* of the segment.
 - If you accidentally place the FSD at the end date of a segment, the decline is anchored to the *end date* of the segment.
 - **Ctrl key** — the curvature of the line (the b value) changes.

To customize your line, right-click it. For more information, see [decline-line customization](#).

Surveillance analysis

With a surveillance analysis, you can create a:

- [Hall plot](#) (single well) — a simple tool to analyze steady-state flow at an injection well.
- [voidage replacement ratio \(VRR\) analysis](#) (groups) — helps identify parts of a field where increased or decreased amounts of water or gas must be injected in order to reach or maintain VRR targets.

In order to generate meaningful results, a well must contain injected water volumes and injecting tubing pressures. Optionally, the well can also contain "time on injection". For more information, see [surveillance analysis theory](#).

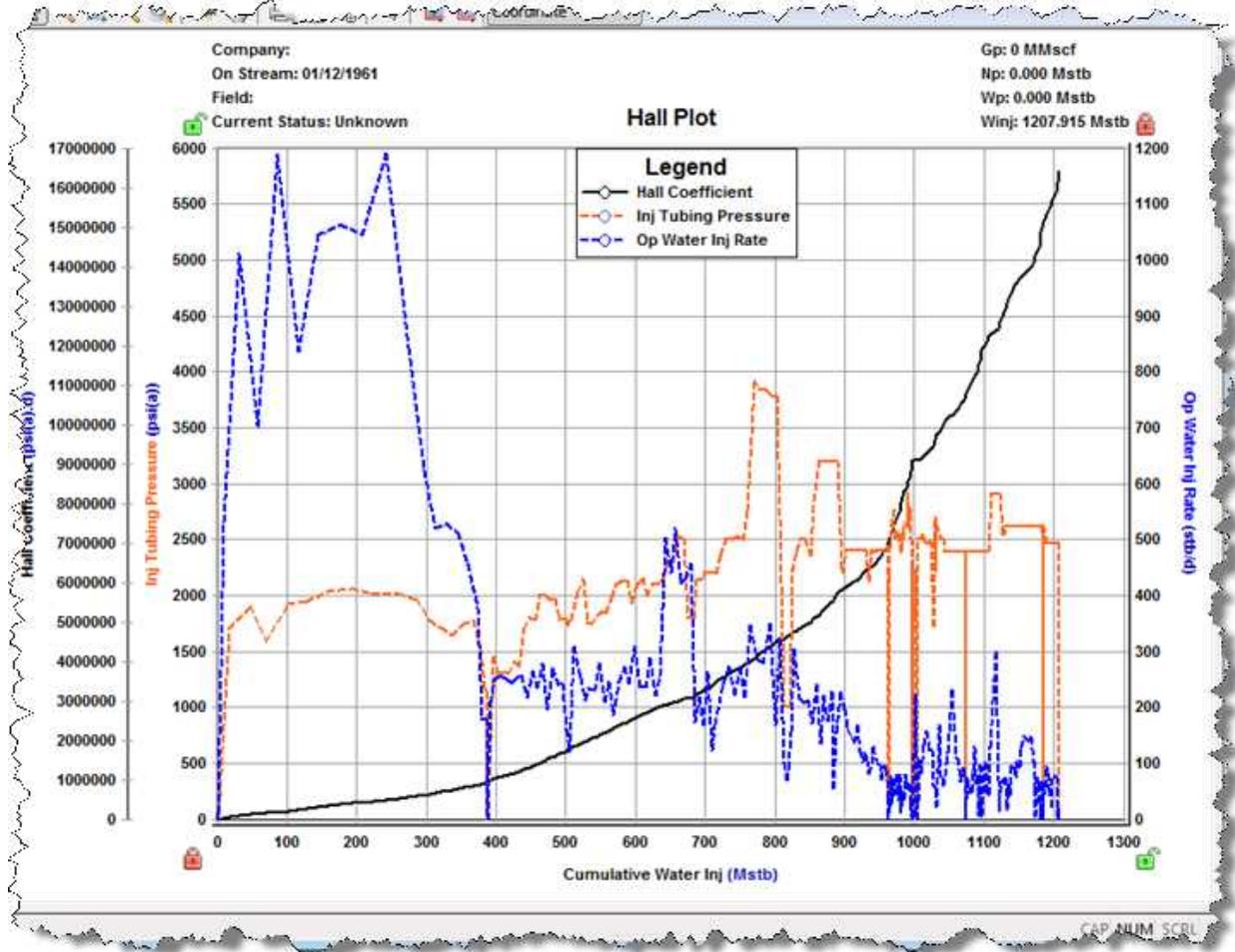
Note: This analysis works with your Harmony Forecast™ license.

Hall plot

The slope of a Hall plot indicates an individual well's average injectivity. At normal conditions, the plot is a straight line; deviations indicate changes in injection conditions. For more information, see [Hall plot theory](#).

By default, the Hall Plot worksheet displays the Hall Coefficient on the left y-axis and Cumulative Water Injected on the x-axis.

To display other datasets in the plot (for example, Injection Tubing Pressure and Operated Water Injection Rate), click the **Plot Selection** tab and then click the datasets you want displayed.



VRR analysis

The voidage replacement ratio (VRR) analysis helps identify parts of a field where increased or decreased amounts of water or gas must be injected in order to reach or maintain VRR targets.

A VRR analysis can display both the instantaneous VRR and cumulative VRR for both water injection and gas injection. The VRR datasets can be plotted versus Time, Cumulative Oil Produced, or Cumulative Water Injected.

To create a VRR worksheet using water injection, the injected values must be entered in Water Inj Volume in the Production editor for individual wells. To create a VRR worksheet using CO₂ injection, the injected values must be entered in Gas Inj Volume (also in the Production editor). Cur-

rently, steam injection volumes are not incorporated in VRR calculations. Optionally, the well could also contain "time on injection".

This worksheet has these buttons in the lower left: Patterns and VRR Settings. If you do not see all these buttons, click >> and select **Show All Buttons**.

Patterns

When you create a new worksheet, all wells are listed in the Unassigned category. Patterns are used to subdivide the wells into groups that are hydraulically connected and usually center around one injector, and the producers it affects or visa versa. These patterns can be created by selecting wells in the list or in the map view, and creating a new pattern or adding and removing wells from existing patterns.

Creating patterns

To create a new pattern in the Patterns pane:

1. Select wells in the **Unassigned** category. Pressing the **Shift** and **Ctrl** keys on the keyboard can be used to select multiple wells.
2. Click the **Add Entity** icon () and select **Create Pattern from selected**.
Or, right-click one of the selected wells and select **Move Selected Items**, then select **(New Pattern)**.

To create a new pattern on the map view:

1. Select wells on the map by clicking the **Area Select** () icon or **Lasso Select** () icon.
2. Click the **Create Pattern** button in the map toolbar.

Modifying patterns

To modify a pattern:

1. Right-click in the Pattern pane.
2. Select one of the following options:
 - **Rename Pattern** — changes the display name of the pattern in the left pane and on the map. A unique name must be used.

- **Edit Pattern Color** — changes the display color of the pattern in the left pane and on the map.

Patterns can be deleted by selecting the pattern and clicking the **Remove Selected Entities** () icon.

VRR settings

VRR settings are as follows:

Pressure Source — determines the pressure used when determining the fluid properties (B_o , B_g , B_w , R_s) in each period when calculating VRR.

- **Use Constant Pressure** — type a constant reservoir pressure, or use the default value (of P_i from the [Properties editor](#)).
- **Use Oil Material Balance Analysis** — select your analysis from the drop-down list and the synthetic reservoir pressure over time is applied to the VRR calculations.

Target — by default, each VRR analysis displays a straight dashed Target VRR line at $VRR = 1$. This is a visual indicator of the relationship between the VRR datasets and your specified target. To display the target VRR line, click the **Show on plot** checkbox. You can change the Target VRR value by typing a new value in the VRR_{TARGET} field.

Note: The Target VRR is based on good reservoir practice.

Pre-Injection Production — the cumulative VRR dataset can include pre-injection production (default setting), or exclude it. When pre-injection production is included, the cumulative VRR reflects the relationship between injected fluids and produced fluids since the beginning of production. When pre-injection production is excluded, the cumulative VRR reflects the relationship between injected fluids and produced fluids since the beginning of injection.

Allocation

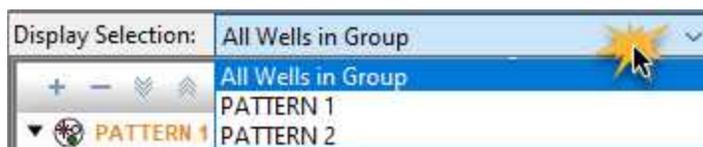
Clicking the Allocation button opens the Pattern Allocation dialog box, which displays the loss factors and pattern allocations for all wells in the group. Loss factors are only applied to injection volumes for a well and allow for partial accounting of the total injection in the VRR calculations. The loss factors default to zero. Allocation splits the production and injection of a well when it is included in multiple patterns. The allocation is 1.0 for the first pattern a well is added to, and zero for subsequent patterns. The allocation cell is blank and disabled for any pattern for which the well is not a member.

Auto Allocate button — automatically sets well allocation to an arithmetic average based on the total number of patterns to which it is a member. For example, if a well is in two patterns, the allocation is set to 0.5 in each pattern.

Dashboard

In the dashboard, there are four plots.

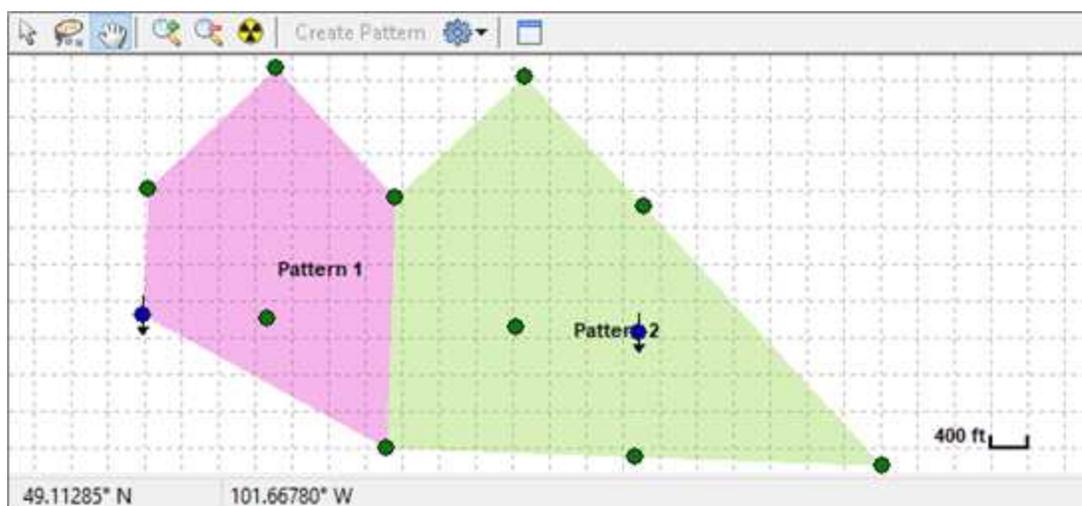
The VRR, Production History, and Ratios plots can display datasets for all wells in the VRR group, or for a certain pattern based on the selection in the following drop-down list:



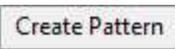
For a description of common plot icons, see [plot toolbars](#).

Map view

The map view displays all wells in the VRR group and all created patterns.

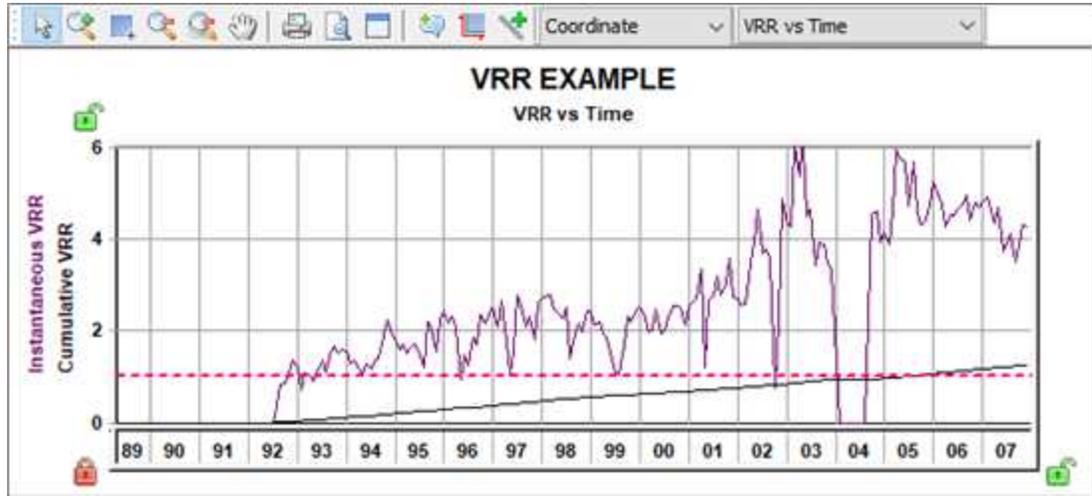


Toolbar icons are as follows:

-  **Create Pattern** — creates a pattern from the selected wells.
-  **Display Settings** — clicking this icon displays a drop-down list with the following options: Wells, Well Names, Well Head, Grid, Scale, Patterns, Pattern Names, and Show All.

VRR plot

This plot displays Instantaneous VRR and Cumulative VRR for the selected pattern.



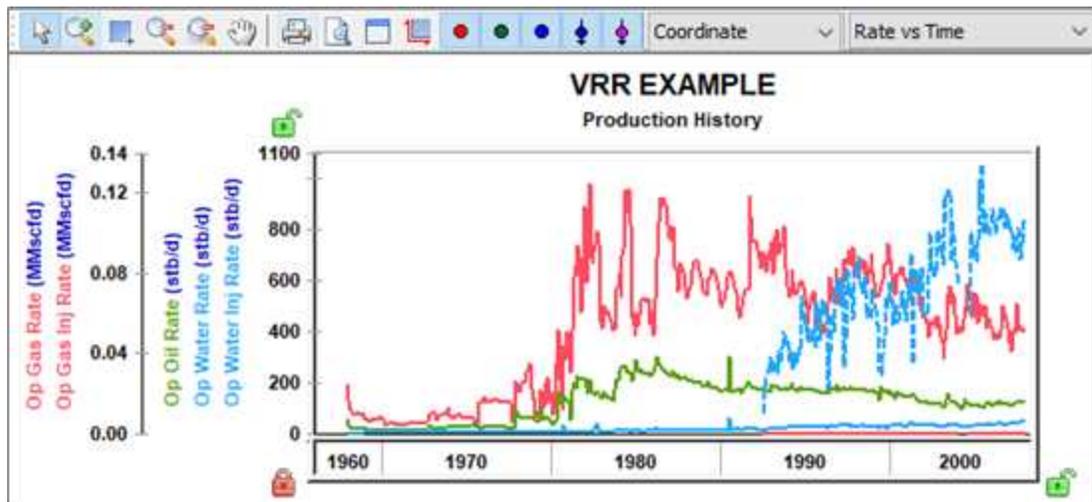
Click the drop-down list to switch between various plot views: VRR vs Time, VRR vs Cum Oil, and VRR vs Cum Water Inj.

Lines on the plot represent the following:

- Dashed pink line — represents the target VRR. This parameter can be changed in [VRR settings](#).
- Solid lines — represent the VRR datasets (purple = instantaneous, black = cumulative).

Production History plot

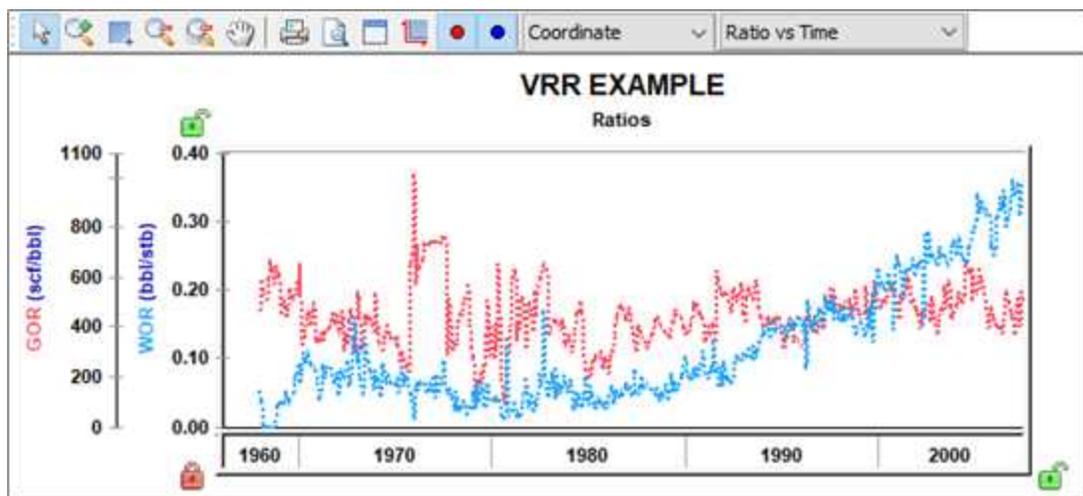
This plot displays historical production and injection rates for the selected pattern.



The Well Symbol icons () are used to show or hide individual datasets on the plot.

Ratios plot

This plot displays historical ratios for the selected pattern.



The Well Symbol icons () are used to show or hide individual datasets on the plot.

Typecurve analysis

With the typecurve worksheet, flowing pressures must be provided at the same frequency as rates in the Production editor (not required for a Fetkovich analysis), and reservoir / fluid

parameters must be entered in the Properties editor. If this data is not provided, the typecurve worksheet remains accessible, but the data is not displayed on the plot.

Note: This analysis works with your Harmony Reservoir™ license.

When creating a typecurve worksheet, select your fluid type, model, and then method (for example, Gas, Fracture, Blasingame).

If you analyze a group of wells, you can change which well is displayed by selecting your well from the **Primary Well** drop-down list. Note that there is no interpretation for these well completion parameters: skin and fracture half length.

Models

Harmony Enterprise supports the following models:

- **Vertical** — a cylindrical reservoir with a vertical well in the center.
 - **Radial** — a cylindrical reservoir with a vertical well in the center.
 - **Water Drive** — a cylindrical reservoir with a concentrically cylindrical aquifer. This model is based on a radial composite model, with the outer region representing the aquifer, characterized by several different levels of aquifer mobility, relative to the reservoir. The mobility ratios range from zero (no aquifer) to 10 (effectively constant-pressure boundaries). The aquifer model assumes a water zone of infinite extent.
- **Vertical with Fracture** — a cylindrical or rectangular (Fetkovich) reservoir with an infinite conductivity fracture in the center.

Finite Conductivity Fracture — a cylindrical reservoir with a finite conductivity fracture in the center.
- **Horizontal** — a square reservoir with a horizontal well in the center. There are actually nine different horizontal well models. Each model represents a different penetration ratio " $L_e / 2x_e$ " (ratio of effective wellbore length to reservoir length) and dimensionless wellbore radius " r_{wD} " (ratio of effective wellbore radius to effective wellbore length).
- **Hz Multifrac** — a horizontal reservoir with multiple vertical fractures.

Compound Linear — an infinite reservoir with a horizontal well and multiple hydraulic fractures (you must specify n_f and L_e).

Methods

Harmony Enterprise supports the following methods:

- [Agarwal-Gardner](#)
- [Blasingame](#)
- [Compound Linear](#)
- [Fetkovich](#)
- [NPI](#)
- [Wattenbarger](#)

Sub-tabs

There are three sub-tabs: plot, forecast, and tables.

Plot

The Plot sub-tab displays sets of typecurves that can be viewed together or separately depending on which checkboxes you click in the Plot Options section.

1. Normalized Rate
2. Integral
3. Raw Data Derivative
4. Derivative
5. Beta-Derivative (in the Fracture model)

The objective of the typecurve analysis is to move data over top of the family of typecurves (click the [Reposition icon](#)) until the data points match one of the typecurves as closely as possible. After you know which typecurve matches your data best, you can select the appropriate parameter from the **Parameter Value** drop-down list.

We recommend beginning the match with normalized rate data and typecurves. To add further confidence in the match, use the derivative, integral and derivative, or cumulative production (Fetkovich) options to provide a more unique analysis.

Note: When one of the typecurve sets is disabled, both the data points and associated typecurves are removed from the plot.

Toolbar

This toolbar has the following unique icons:

-  **Tools to Select Data Points for Filtering** — opens an additional toolbar with [point-selection options](#).
Tip: Selection of filtered-out (disabled) points is shared between all typecurve, unconventional reservoir, and FMB analyses for the same fluid type. In addition, these selections are saved when you export to a local database, or import from a local database.
-  **Reposition Data on Plot** — drag data across the screen.
-  **Reset Plot Attributes** — resets your plot attributes to default settings.
-  **Fully Automatic** — removes the outliers in your data by applying a median filter.
-  **Enable / Disable Square Log-Log Plot** — when enabled, the current plot is made proportional for comparison purposes. Clicking the icon again disables this feature.
-  **Single Annotation** — adds a single annotation to a specific point on your typecurve.
-  **Linked Annotations** — synchronizes your annotation across your typecurve, FMB, unconventional reservoir, and data filter plots. For example, if you move your annotation on one plot using the keyboard arrow keys, the arrow is synchronized on the other plots.
-  **Data Filter** — opens the Data Filter dialog box where you can select points to hide from typecurve matching.
-  **Options** — opens the Typecurve Options dialog box where you can set your derivative options, typecurve settings, and rate options.

For information on common plot icons, see [plot toolbars](#).

Forecast

The Forecast sub-tab displays your forecast: results, options, and constraints. You can send your plot to a comparison plot, by right-clicking it and selecting **Send Plot to Comparison Plot**. For information on other options, see [plot options](#).

The forecast toolbar has the same common icons described in [plot toolbars](#).

Tables

The Tables sub-tab displays your forecast data in a tabular format.

Agarwal-Gardner typecurve method

The Agarwal-Gardner method (SPE 057916, 1998) is a practical tool that can estimate the gas (or oil) in-place, as well as reservoir permeability, skin effect, and fracture half-length (for hydraulically fractured wells). The accuracy of this method has been verified through numerical simulations. These modern decline typecurves represent advancement over Blasingame typecurves because a clearer distinction can be made between transient and boundary-dominated flow periods. This method also features curves containing derivative functions, similar to those used in the pressure transient literature, to aid in the matching process. The raw data derivative can also be used to assist in flow regime interpretation.

Note: For information on the Agarwal-Gardner typecurve theory and equations, see [Agarwal-Gardner typecurve theory](#).

The Agarwal-Gardner typecurve method uses the following models:

- **Radial**
- **Fracture** (cylindrical)
- **Water Drive**

Boundary-dominated match

To obtain information about reserves and drainage areas, we recommend that you focus on the boundary-dominated (depletion) stems of the typecurves. These are located on the right-side of the plot, where each set of typecurves converges to a single line. The Agarwal-Gardner typecurve method does not require hyperbolic exponent values. Instead, the data is matched on the single depletion stem. As the data is moved about the plot, the OGIP / OOIP is continuously updated on the Analysis tab.

For gas reservoirs whose fluid properties are strongly a function of pressure, the data points appear to "stretch" and "contract" as they are moved around the screen. This is because of the pseudo-time effect. Harmony Enterprise recalculates gas properties at average reservoir pressures based on the calculated OGIP from the typecurve match. As the match is modified, OGIP,

average reservoir pressure, and material balance pseudo-time are automatically recalculated, and the data points are repositioned accordingly.

Transient match

To obtain information about permeability and skin, we recommend that you focus on the transient stems of the typecurves. On the Agarwal-Gardner typecurve plot, these appear on the left-side of the plot as a “fan” of different r_{eD} values for the radial and water-drive models, r_e / x_f values for the fracture model. Select the typecurve that best matches the data; this provides an associated r_{eD} (or r_e / x_f) value.

From the selection, Harmony Enterprise calculates:

- skin for a radial model.
- fracture half-length for a fracture model.
- mobility ratio and skin for a water-drive (transient) model.

Blasingame typecurve method

Blasingame represents the first of the modern typecurve methods (SPE 028688, 1994). It features pressure normalized rates, and introduces the concept of material balance time (that is, boundary-dominated superposition time) to generate fully analytical constant rate typecurves featuring a single depletion stem, regardless of the reservoir structure (shape and size) or drive mechanism. Blasingame analysis results include skin factor, formation permeability, in-place fluid volumes, and reservoir drainage area. The flow-rate integral and flow-rate integral derivative functions allow for more accurate decline typecurve matches than would be possible using flow-rate data alone. These integral functions also eliminate problems associated with the analysis of field production data with erratic production rate and sandface pressure behavior. The Blasingame method is particularly useful in the modeling of suspected elliptical drainage patterns and open-hole horizontal wells, which have transitioned into boundary-dominated flow.

Note: For information on the Blasingame typecurve theory and equations, see [Blasingame typecurve theory](#).

The Blasingame typecurve method uses the following models:

- **Radial**
- **Fracture** (cylindrical)
- **Water Drive**

- **Horizontal**
- **Finite Conductivity Fracture** (cylindrical)

Boundary-dominated match

To obtain information about reserves and drainage area, we recommend that you focus on the boundary-dominated (depletion) stems of the typecurves. These are located on the right-side of the plot, where each set of typecurves converges to a single line. The Blasingame typecurve analysis does not require hyperbolic exponent values. Instead, the data is matched on the single depletion stem. As the data is moved about the plot, the OGIP / OOIP is continuously updated on the Analysis tab.

For gas reservoirs whose fluid properties are strongly a function of pressure, the data points appear to "stretch" and "contract", as they are moved around the screen. This is because of the pseudo-time effect. Harmony Enterprise recalculates gas properties at average reservoir pressures based on the calculated OGIP from the typecurve match. As the match is modified, OGIP, average reservoir pressure, and material balance pseudo-time are automatically recalculated, and the data points are repositioned accordingly.

Transient match

To obtain information about permeability and skin, you should focus on the transient stems of the typecurves. On the Blasingame typecurve plot, these appear on the left-side of the plot as a "fan" of different r_{eD} values for the radial and water-drive models, r_e / x_f values for the fracture and finite conductivity fracture models, and L_D for the horizontal model. You can select the best matching typecurve, which provides an associated r_{eD} (or r_e / x_f , L_D) value.

From the selection, Harmony Enterprise calculates:

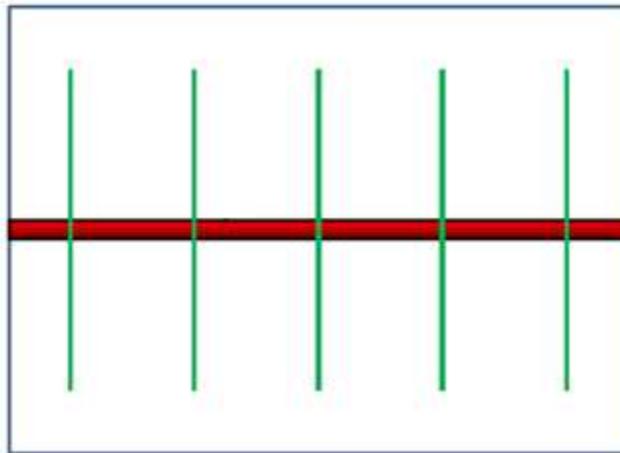
- permeability and skin for the radial model.
- permeability and fracture half-length for the fracture model.
- mobility ratio, permeability, aquifer permeability, and skin for the water-drive (transient) model.
- vertical and horizontal permeability, and skin for the horizontal model.
- permeability, fracture half-length, and fracture-equivalent skin for the finite conductivity fracture model.

Compound linear typecurve method

Compound linear typecurves are useful for analyzing horizontal multifrac wells producing from tight gas or shale wells.

Note: For more information on Compound Linear typecurve theory and equations, see [compound linear typecurve theory](#).

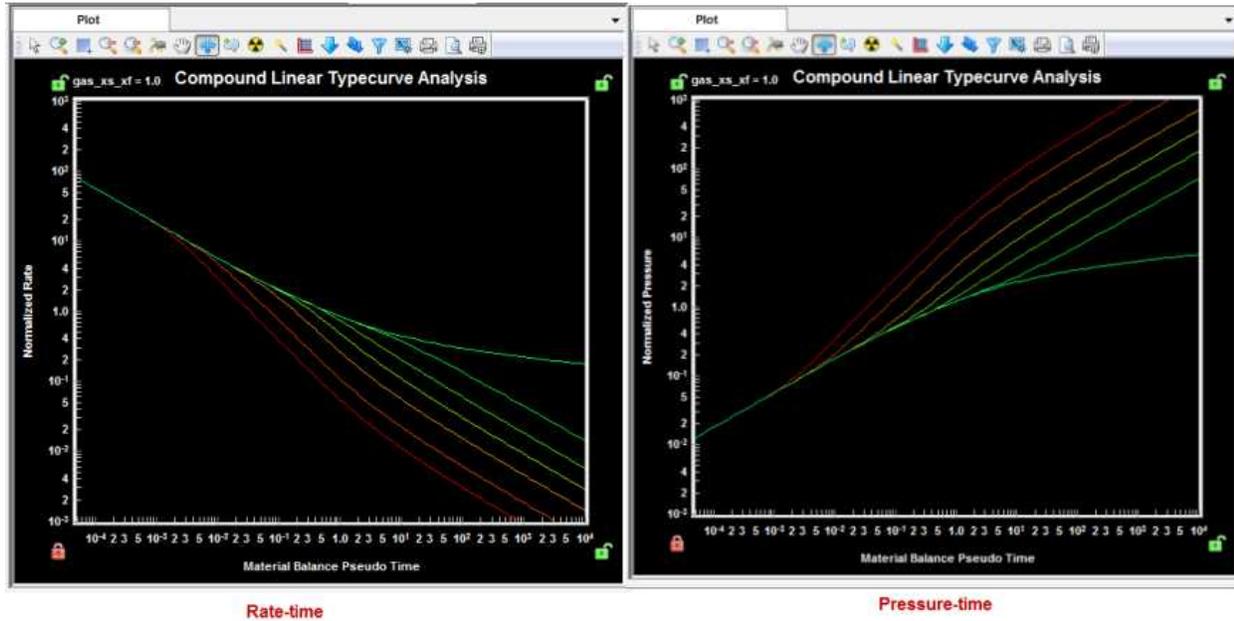
This method uses the horizontal multifrac model.



There are two sets of compound linear typecurves:

1. Pressure-time — uses normalized pressures: the constant rate solution
2. Rate-time — uses normalized rates: the reciprocal of the constant rate solution

Rate-time and pressure-time are reciprocals of one another, and simply plot the data on the typecurves differently.

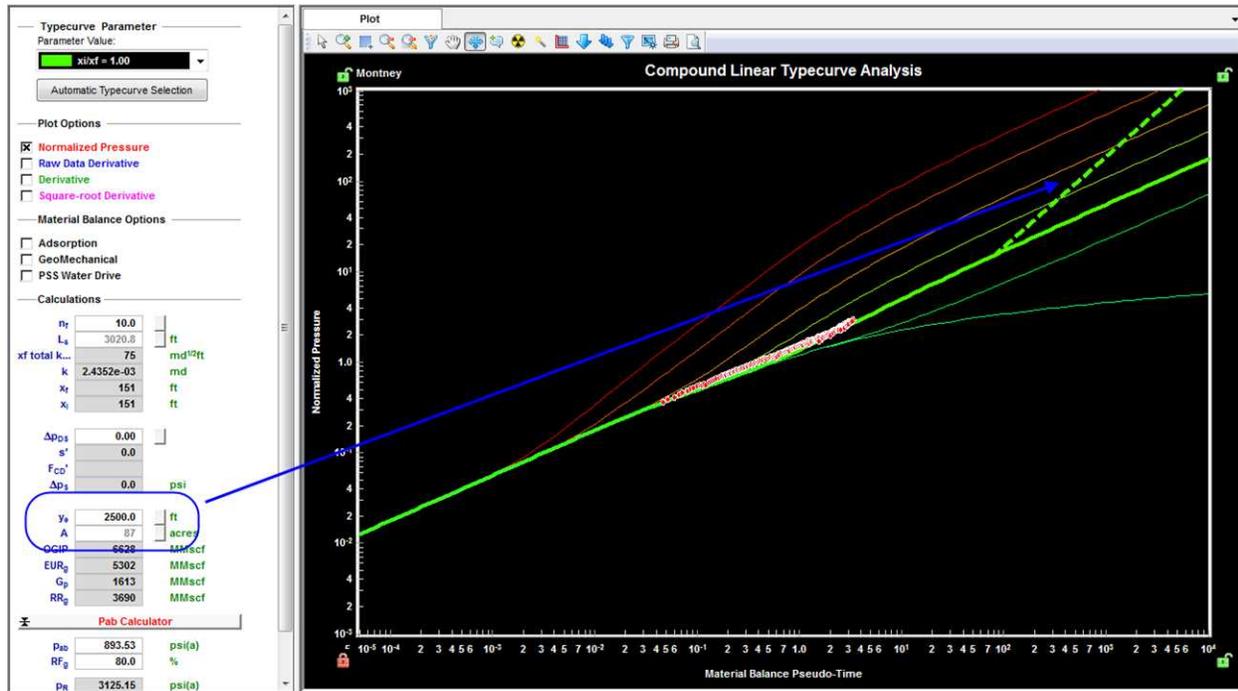


Boundary-dominated match

As the compound linear typecurves were developed using an infinitely large reservoir, there is no boundary-dominated flow stem. However, entering a value for either Y_e or Area (A), will produce a dashed boundary-dominated flow line that intersects the selected typecurve.

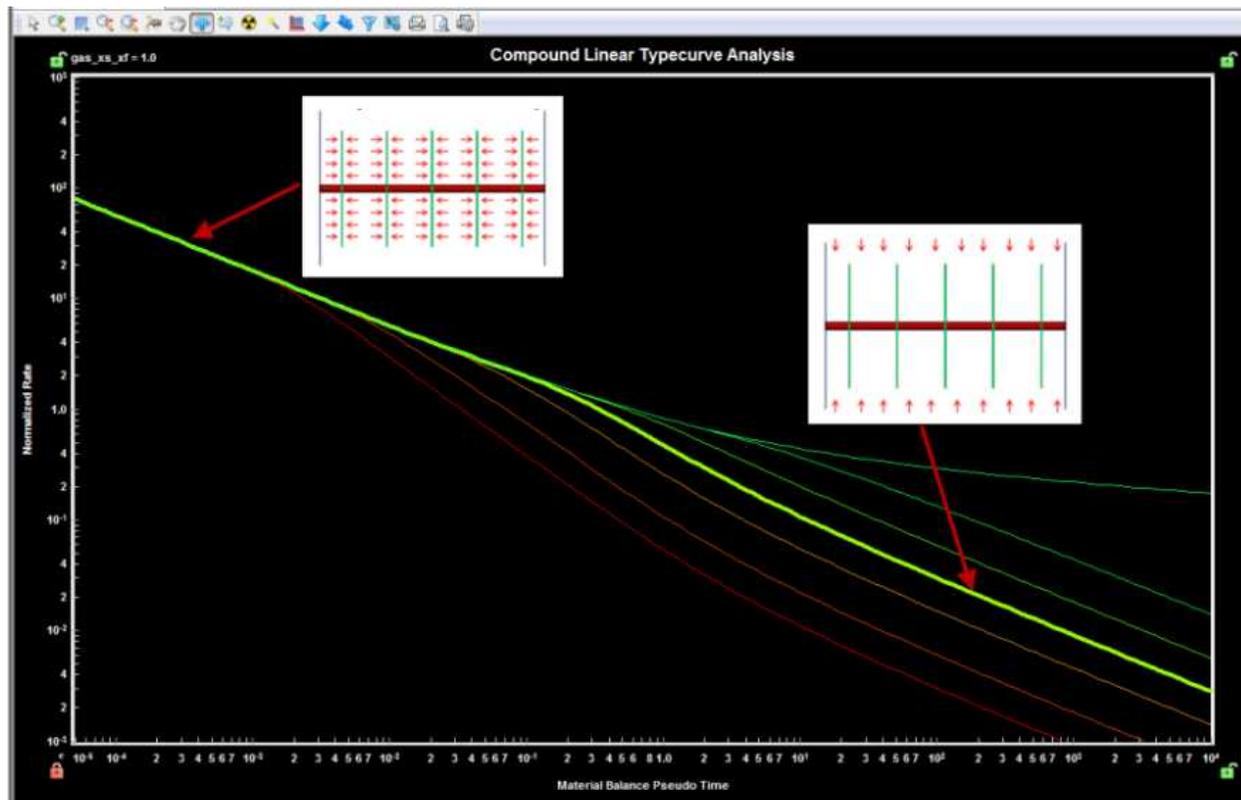
Note: A typecurve must be selected before the boundary-dominated line is plotted.

If boundaries have been reached, the production data deviates from the compound linear typecurve on to the boundary-dominated line.

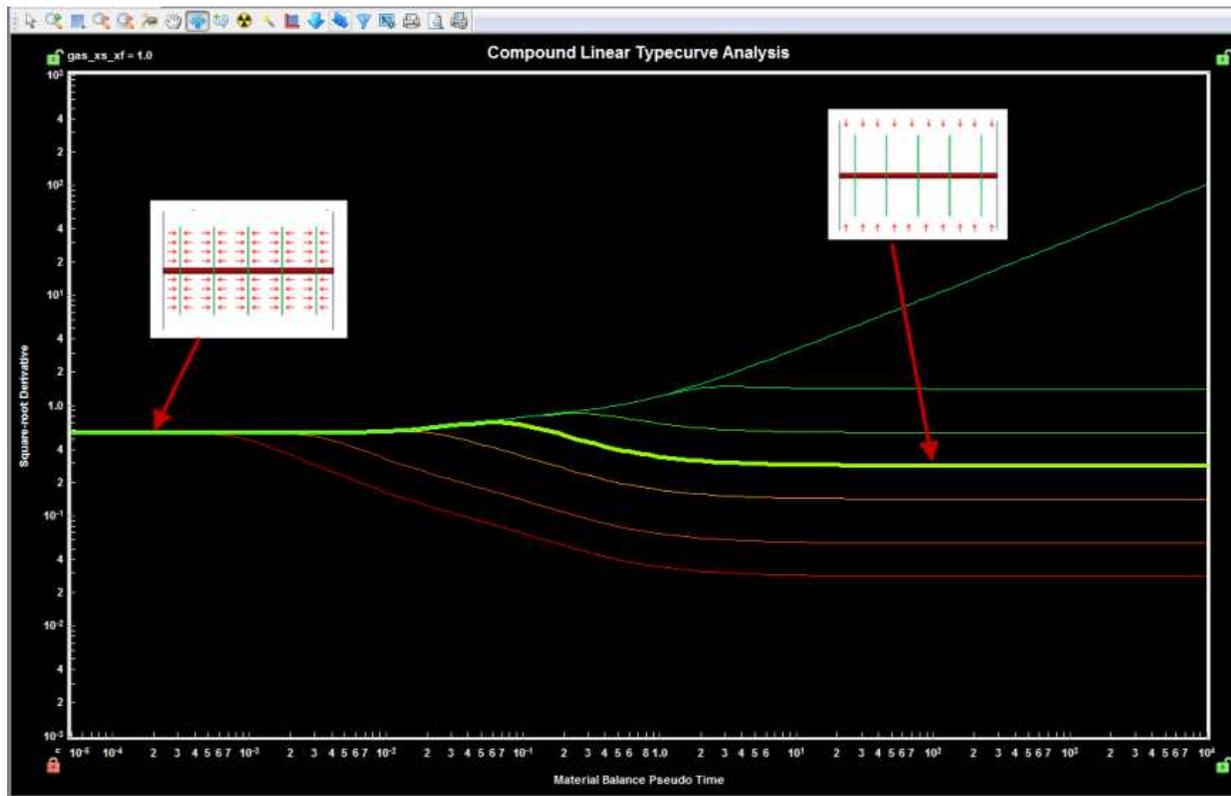


Transient match

Compound linear typecurves were developed for a horizontal, multfrac well in an infinite reservoir. The first half slope indicates linear flow into the fractures, while the second half slope indicates linear flow into the fractured region. The two half slopes are connected by a transition period. Most production data is expected to fall in the transition zone.



Selecting the "Square Root Derivative" plot displays the linear flow periods as flat lines, which may be helpful for matching data.



Matching data to a typecurve gives the x_i / x_f ratio. Entering a value for number of fractures (n_f) calculates the following values:

- L_s
- $x_f \sqrt{k_{SRV}}$
- X_f
- X_i

Note: Entering a value for L_s calculates n_f .

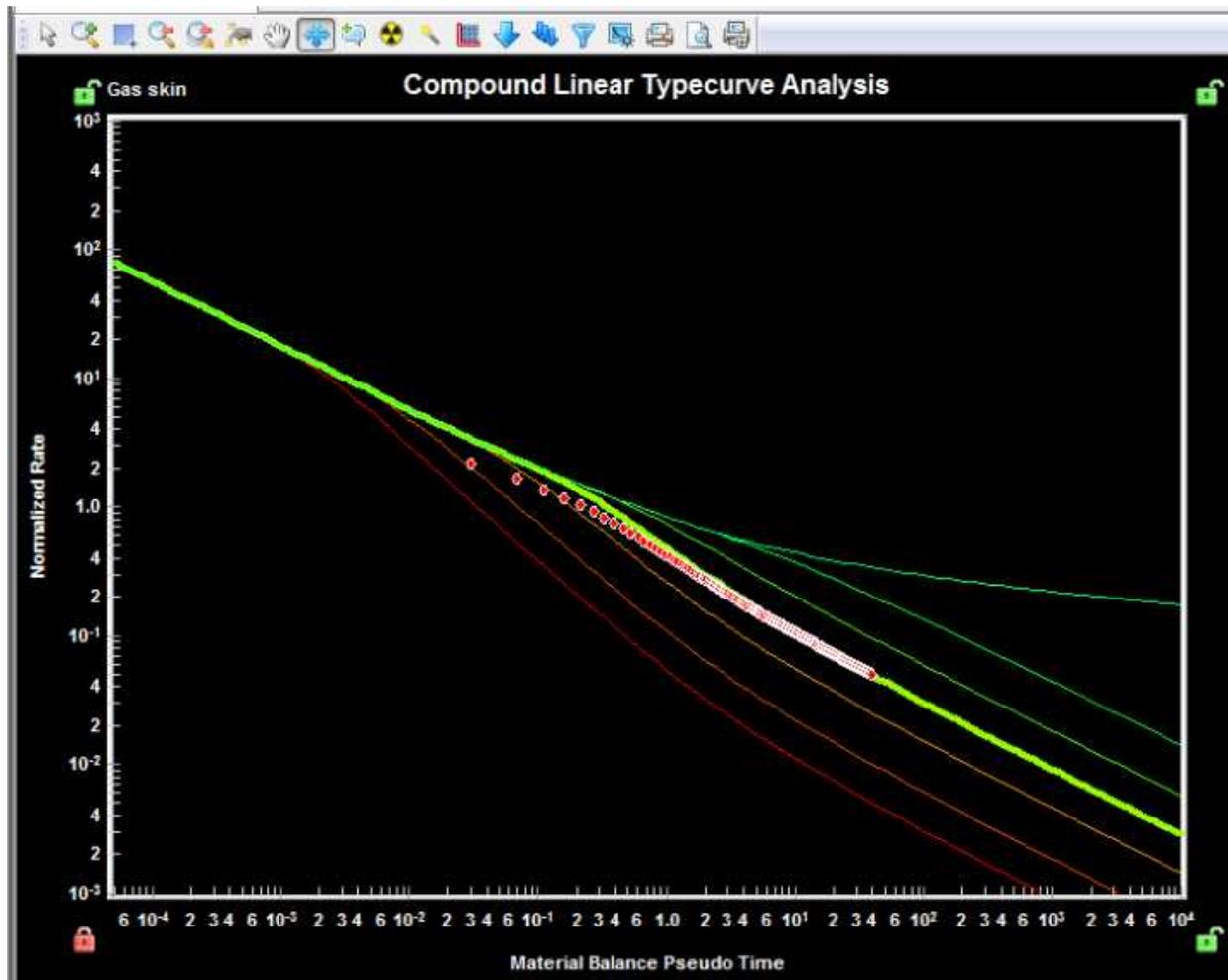
Skin

Generally, skin effects impact the first linear flow period, causing the data to deviate from the ideal typecurve.

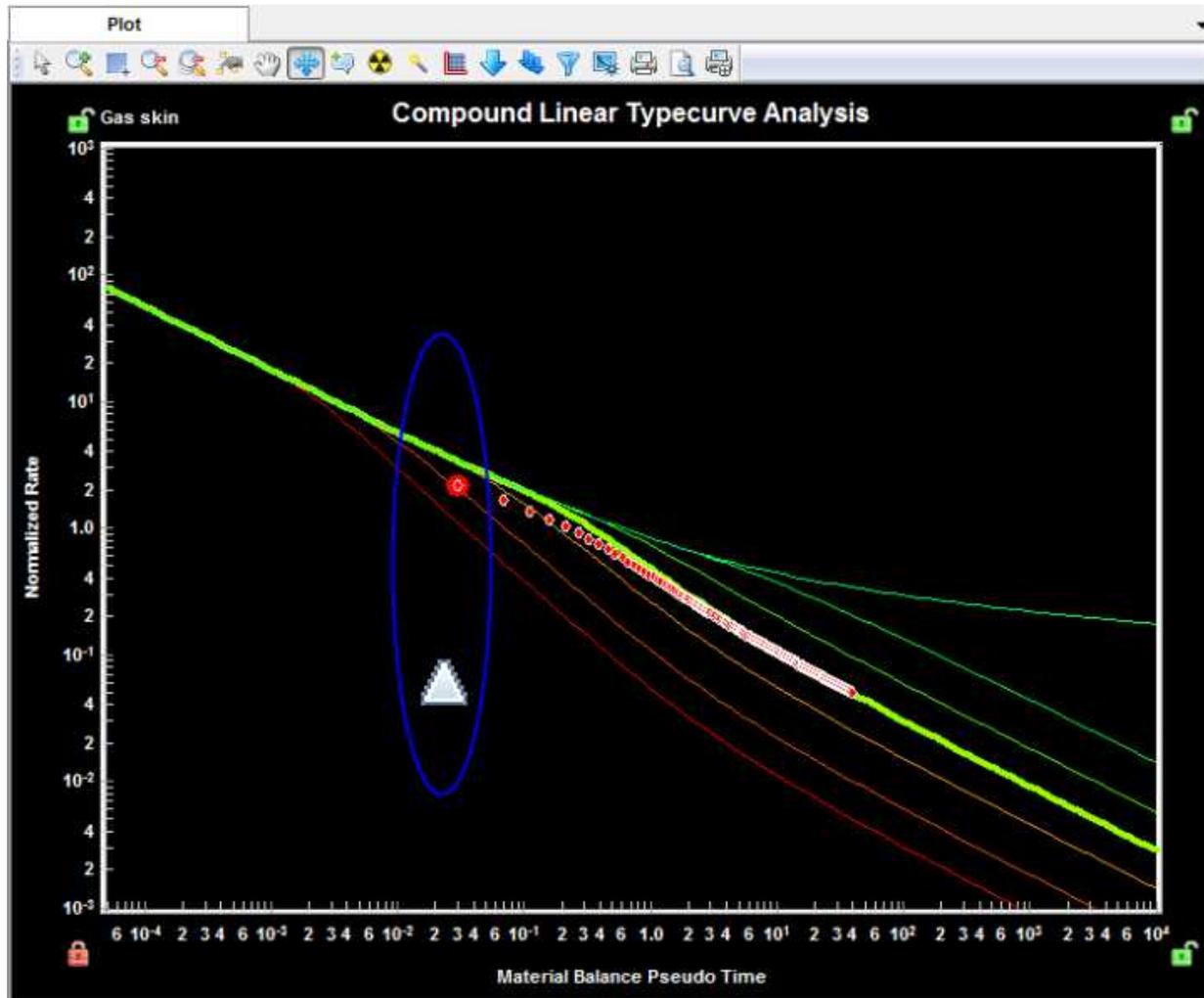
To correct for skin effects on the Normalized Pressure or Rate curves:

1. Match the later part of the data to a typecurve.
2. Select the typecurve that matches the data most closely.

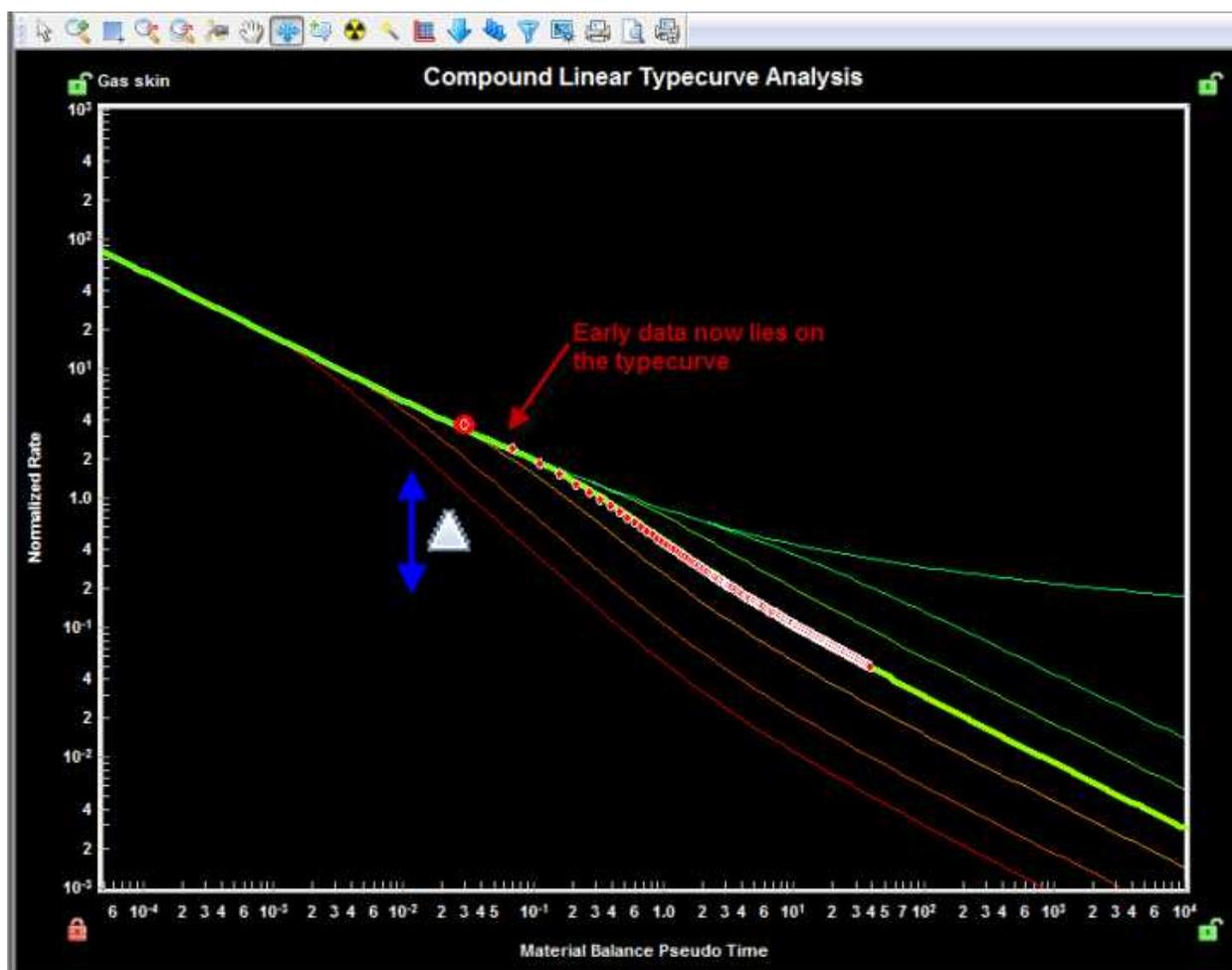
3. Enter the number of fractures (n_f) or Ls.



4. Right-click the plot and hold your mouse button. This highlights the data point closest to the top left corner for Rate-Time (bottom left for Pressure-Time), and the cursor changes to a triangle.



5. While continuing to hold the right-mouse button, move the cursor up or down until the early portion is matched on the typecurve.



Moving the data in this manner populates the Δp_{DS} cell. This value is then used to convert the dimensionless pressure drop into an equivalent apparent skin, apparent fracture conductivity, and dimensional pressure drop.

For more details on the calculations, see [compound linear typecurve theory](#).

Fetkovich typecurve method

The Fetkovich typecurve method (SPE 004629, 1980) was the first analysis method to use analytical typecurve matching for production data. It is a semi-analytical approach in that typecurves are generated from analytical solutions of transient (infinite) radial systems at constant flowing pressure, while the boundary-dominated flow period is defined using hyperbolic decline typecurves, originally developed by Arps. In addition to reserves, calculated from the depletion stem (b-value) match, this analysis provides diagnostic power through the determination of reservoir

permeability and wellbore skin factor. Rate normalization (SPE 012179, 1984) has been included to account for changing operating conditions (that is, changes in flowing pressures) to more reliably determine permeability and skin. With reinitialization, you can analyze the transient production data signature of post-buildup production to diagnose permeability and skin. A clear advantage of this method over modern typecurve methods is that it does *not* plot data using superposition time functions, which may bias the interpretation. It remains a popular technique for the analysis of conventional vertical oil and gas wells. Fetkovich plots are even used to describe the behavior of unconventional well production data (for example, Bakken oil wells). The limitation of this technique is that the transient typecurves are restricted to radial flow systems, and the method does not directly calculate original-hydrocarbons-in-place (as is the case in modern methods); it is estimated through simple material balance.

Note: For information on the Fetkovich typecurve theory and equations, see [Fetkovich typecurve theory](#).

The Fetkovich typecurve method uses the following models:

- **Radial**
- **Fracture** (rectangular)

Boundary-dominated match

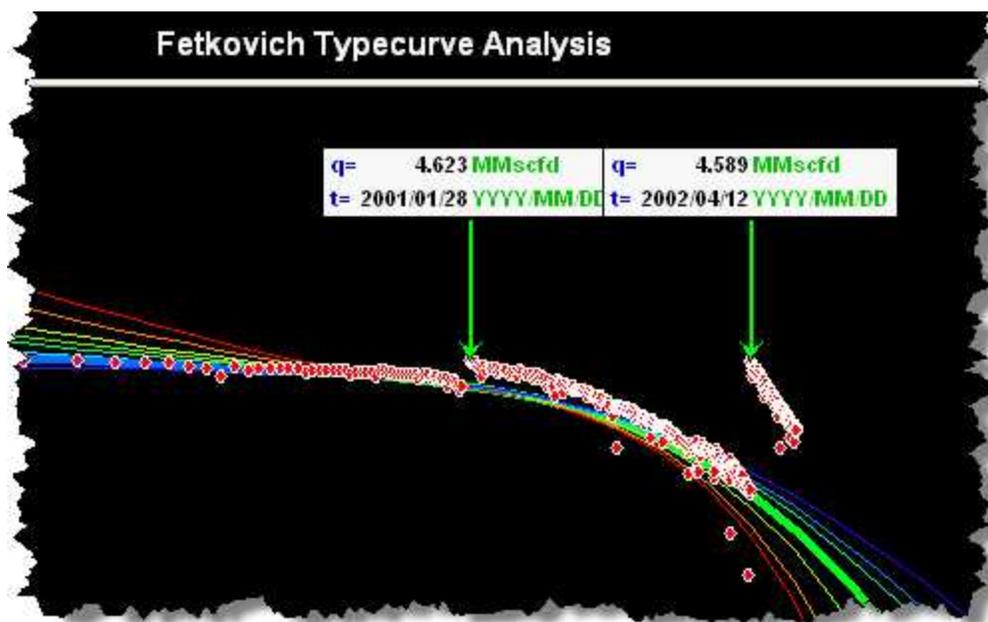
To obtain information about reserves and drainage areas, we recommend that you focus on the boundary-dominated (depletion) stems of the typecurves. These are located to the right of where the Rate vs. Time and the Cumulative Production vs. Time typecurves intersect. Each of the depletion stems represents a different b value, identical to the b values used in the hyperbolic Arps analysis. After a b value has been selected, Harmony calculates recoverable reserves and expected ultimate recovery. If a sandface flowing pressure is specified on the Analysis tab, Harmony also calculates drainage area and original gas-in-place.

Transient match

To obtain information about permeability and skin, we recommend that you focus on the transient stems of the typecurves. These are located to the left of where the Rate vs. Time and the Cumulative Production vs. Time typecurves intersect. Each of the transient stems represents a different r_{eD} value. Once a r_{eD} value has been selected and a sandface flowing pressure is specified, Harmony calculates permeability and skin.

Time reinitialization

The fundamental assumption in a Fetkovich transient analysis is a constant sandface flowing pressure. Although an ideal case, this assumption is rarely representative of true operating conditions, particularly in early (transient) production. A well may be subject to shut-ins or operational changes during its life. When a well is shut in, or undergoes a change in operating conditions, the constant sandface flowing pressure assumption is no longer valid. When the well resumes production, a new additional transient effect is introduced to the wellbore. Additional transient effects in the wellbore are indicated by the green arrows in the screenshot below.

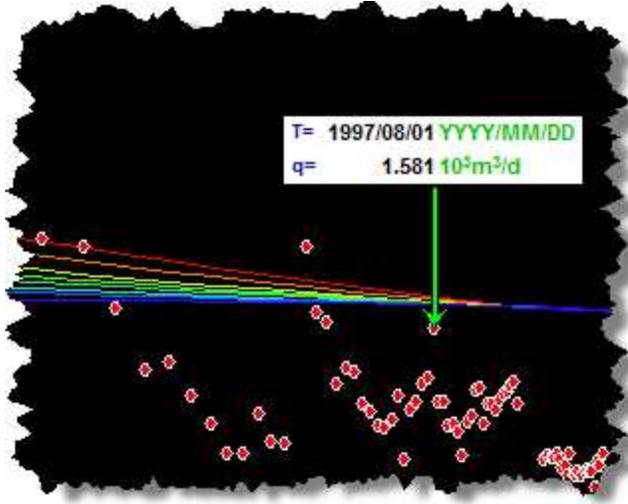


Fetkovich suggested a method called "time reinitialization" to analyze a dataset with multiple transient effects. This method resets the time at the start of each additional transient effect to zero, allowing you to specify additional transient effects on the typecurve plot. Once specified, the time associated with the first rate of each new transient flow period is reset to zero. As a result, the dataset is smoothed on the typecurve, allowing you to continue with the Fetkovich typecurve match.

To perform a Fetkovich time reinitialization:

1. Identify the beginning of each additional transient flow period either from Fetkovich or the Raw Data plot.
2. Click the **Add Reinitialization Arrow** icon () on the Fetkovich plot tool bar.

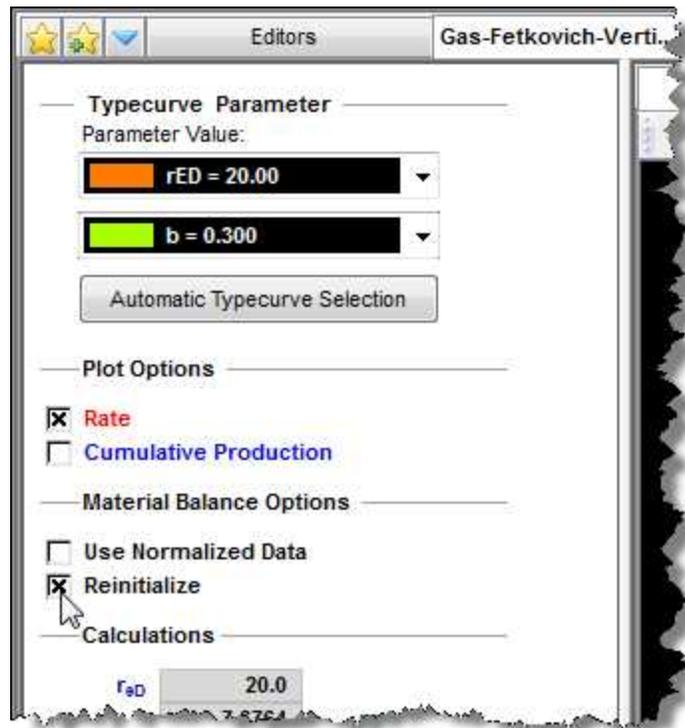
- Click the data point representing the beginning of the additional transient flow period. The green reinitialization arrow is displayed at that point.



- Move the arrow left and right using the arrow keys on the keyboard.
- Remove the arrow by clicking the arrow's annotation box, and then pressing the **Delete** key on the keyboard.

Note: To create multiple additional transient periods, click the **Add Reinitialization Arrow** icon again, then repeat the process explained above. (The maximum number of additional transient periods permitted in Harmony is ten.)

- Select the **Reinitialize** option under Material Balance Options in the parameters pane.



5. Continue with the Fetkovich typecurve matching method.

NPI typecurve method

Normalized pressure integral (NPI) typecurves are the inverse of Agarwal-Gardner typecurves. The NPI method is often preferred by those who come from a pressure transient analysis domain, and are accustomed to seeing log-log plots using normalized pressure, instead of normalized rates.

Note: For information on the NPI typecurve theory and equations, see [NPI typecurve theory](#).

The NPI typecurve method uses the following models:

- **Radial**
- **Fracture** (cylindrical)
- **Water Drive**

Boundary-dominated match

To obtain information about reserves and drainage areas, we recommend that you focus on the boundary-dominated (depletion) stems of typecurves. These are located on the right-side of the plot, where each set of typecurves converge to a single line. The NPI typecurve method does not require hyperbolic exponent values. Instead, the data is matched on the single depletion stem. As the data is moved about the plot, the OGIP / OOIP is continuously updated on the Analysis tab.

For gas reservoirs whose fluid properties are strongly a function of pressure, the data points appear to "stretch" and "contract" as they are moved around the screen. This is because of the pseudo-time effect. Harmony Enterprise recalculates gas properties at average reservoir pressures based on the calculated OGIP from the typecurve match. As the match is modified, OGIP, average reservoir pressure, and material balance pseudo-time are automatically recalculated, and the data points are repositioned accordingly.

Transient match

To obtain information about permeability and skin, you should focus on the transient stems of the typecurves. On the NPI typecurve plot, these open on the left-side of the plot as a "fan" of different r_{eD} values for the radial and water-drive models, r_e / x_f values for the fracture model. You can select the best matching typecurve, which provides an associated r_{eD} (or r_e / x_f) value.

From the selection, Harmony Enterprise calculates:

- permeability and skin for the radial model.
- permeability and fracture half-length for the fracture model.
- mobility ratio, permeability, aquifer permeability, and skin for the water-drive (transient) model.

Wattenbarger typecurve method

Wattenbarger typecurves are used for analyzing linear flow. They are particularly useful in the analysis of shale gas wells, which tend to exhibit long-term linear flow followed by a transition towards boundary-dominated flow.

Note: For information on the Wattenbarger typecurve theory and equations, see [Wattenbarger typecurve theory](#).

The Wattenbarger typecurve method uses the **Vertical with Fracture** (rectangular) model.

Boundary-dominated match

To obtain information about reserves and drainage areas, we recommend that you focus on the boundary-dominated (depletion) stems of typecurves. These are located on the right-side of the plot, where each set of typecurve converges to a single line. The Wattenbarger typecurve method does not require hyperbolic exponent values. Instead, the data is matched on the single depletion stem. As the data is moved about the plot, the OGIP / OOIP is continuously updated on the Analysis tab.

For gas reservoirs whose fluid properties are strongly a function of pressure, the data points appear to "stretch" and "contract", as they are moved around the screen. This is because of the pseudo-time effect. Harmony Enterprise recalculates gas properties at average reservoir pressures based on the calculated OGIP from the typecurve match. As the match is modified, OGIP, average reservoir pressure, and material balance pseudo-time are automatically recalculated, and the data points are repositioned accordingly.

Transient match

To obtain information about fracture half length, reservoir size, and well location in the reservoir, you should focus on the transient stems of typecurves. On the Wattenbarger typecurve plot, these appear on the left-side of the plot as different y_e / y_w values for the dimensionless channel model. You select the best fitting typecurve, which provides an associated y_e / y_w value.

From the selection and the permeability you define, Harmony Enterprise calculates:

- fracture half length
- reservoir width
- reservoir length
- well location

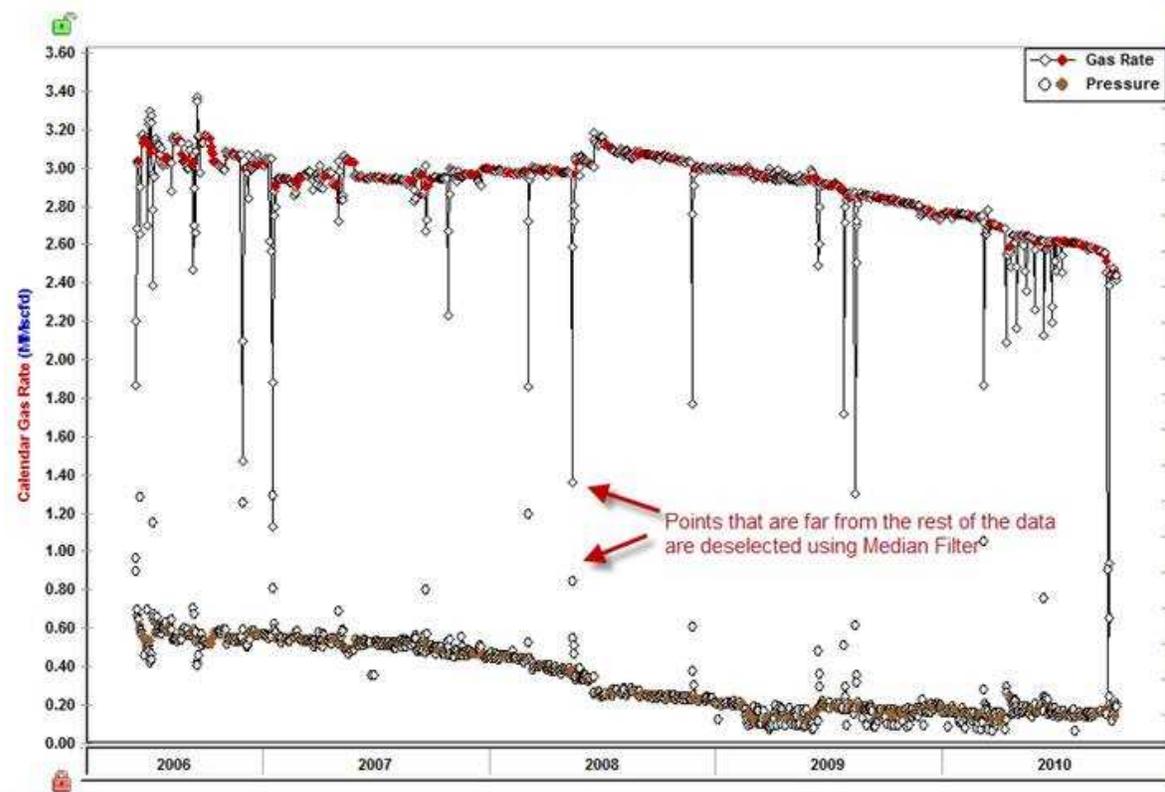
Data filter dialog box

This dialog box is commonly used when you click the filter data for an FMB, typecurve, numerical URM, or unconventional reservoir analysis.

This dialog box has the following important icons:

- **Tools to Select Data Points for Filtering**  — opens an additional toolbar with point-selection options.

- **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.
- **select all data points** — selects all the data points on the plot.
- **deselect all data points** — deselects all the data points on the plot.
- **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.
- **Fully Automatic**  — select one of these options:
 - **Median Filter** — used to make data less noisy by deselecting data points that are far from the rest of the data (those points are likely to be outliers). Note that the dataset needs to have at least 20 points for this filter to be applicable.



- **Liquid Load Filter** — in some cases, flowing pressures are not measured at sandface; instead they are measured at the wellhead, and Harmony

Enterprise calculates sandface pressures (see [pressure loss calculations](#)) based on given wellhead pressures in the [wellbore editor](#). If the well is experiencing liquid loading, calculated sandface pressures may be inaccurate. Therefore, you may want to exclude corresponding data points from the analysis. With this filter, you can deselect data points where the well is experiencing liquid loading. For more information, see [liquid lift calculations](#).

- **Saturated Filter** — used to identify the portion of the data where flowing pressure is below the bubble point pressure (oil and gas flowing in the reservoir). For more information, see [saturated filter](#).

For information on common plot icons, see [plot toolbars](#).

Unconventional reservoir analysis

The unconventional reservoir module (URM) analysis is used to identify linear and/or boundary-dominated flow regimes within your data. Additionally, this analysis generates production forecasts for shale or tight oil / gas wells. This analysis requires sandface flowing pressures, production rates, and reservoir / fluid parameters. If the required pressures, rates, and properties are not filled in, the parameters pane of the analysis is disabled. For more information on the calculations, see [unconventional reservoir theory](#).

Note: This analysis works with your Harmony Reservoir™ license.

This analysis has the following solution options:

- **Constant Pressure** — the constant pressure solution for a basic linear flow model. An analysis line is fit to the data on a Reciprocal Rate vs Square Root Time plot. The slope and y-intercept of the analysis line are used to determine the linear flow parameters, along with apparent skin or apparent fracture conductivity, respectively.
- **Variable Pressure** — the constant rate solution for a basic linear flow model. An analysis line is fit to the data on a Normalized Pressure vs Square Root Time plot. This accounts for changing flowing pressures when interpreting the slope of the square-root time plot. The slope and y-intercept of the analysis line are used to determine the linear flow parameters, along with apparent skin or apparent fracture conductivity, respectively.
- **Superposition Time** — the superposition of the constant rate solution for a basic linear flow model applied over time to account for variations of rate over time. An analysis line is fit to the data on a Normalized Pressure vs Linear Superposition Time plot, or Material Balance Time plot, depending on the time

option selected in the parameters pane. The slope and y-intercept of the analysis line are used to determine the linear flow parameters, along with apparent skin or apparent fracture conductivity, respectively.

- **Deterministic** — creates an analysis based on known parameters.
- **Most Likely** — creates an analysis based on a range of values, and produces "most likely" values that can be used to estimate model parameters.

Note: The production forecast for the variable pressure and superposition worksheets is estimated using constant sandface pressure (p_{wff}).

Note: For a multiphase oil URM analysis, pseudo-pressure is used instead of pressure. This may impact your data-point selection, if you manually best fit your data points with Harmony Enterprise 2017.3 or earlier, and selected the **Changing Properties (Pseudo-Pressure)** checkbox. It is now called the Multiphase (Pseudo-Pressure) checkbox.

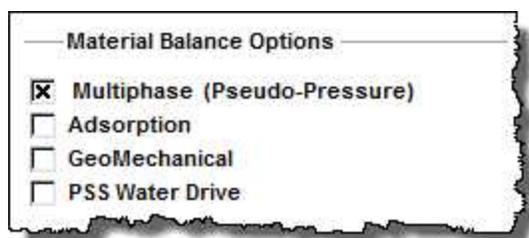
Unconventional Reservoir pane

In the Unconventional Reservoir pane, enter the required parameters and select your options.

Parameters

Parameters include the inputs you specify, or the default Harmony Enterprise values and calculated values from the plot interpretations.

Additional gas options for adsorption and geomechanical models can be used by clicking their checkboxes. These model options require that the Langmuir isotherm and permeability and/or compressibility ratio correlations be entered in the [Properties editor](#).



- **Multiphase (Pseudo-Pressure)** — accounts for the variation of oil properties with pressure. Calculations use the Oil properties that are set in the [Properties editor](#).
- **Adsorption** — includes the effect of adsorbed gas.

- **GeoMechanical** — accounts for the variation in rock properties (permeability and formation compressibility) with pressure. Calculations use the rock properties that are set in the Geomechanical section of the Properties editor. Note that for the Oil URM analysis, this option is only available when the Multiphase (Pseudo-Pressure) option is selected.
- **PSS Water Drive** — accounts for pseudo-steady state (PSS) water drive (additional water drive analysis parameters are displayed).

The flowing pressure inputs in the Forecast parameters section are used with the slope of the Square Root Time plot to determine $x_f\sqrt{k}$. You can enter the drainage area, or area of SRV, but by default, these values come from the OOIP / OGIP on the flowing material balance (FMB) plot. Changes to the location of the end of linear flow line (t_{elf}) on the Square Root Time plot updates the OOIP / OGIP. The decline exponent, b , and the final gas rate are used to calculate the hyperbolic decline forecast. The start date is the end of production data for the well. The Δt is set based on the forecast duration to reach the final rate, and corresponds to the end date. Either q_f or Δt can be entered, and the other value is calculated.

Forecast Parameters		
P_{wf}	Required	psi(a)
A_{SRV}	227	acres
b	0.000	
q_r	5.0	stb/d
Start Date	03/25/2011	MM/DD/YYYY
Δt		month
End Date		MM/DD/YYYY

The second half of the parameters pane displays calculated values from the interpretations:

- The $x_{f\ total}\sqrt{k}_{SRV}$ is determined from the slope of the analysis line on the Square Root Time plot. Here k is effective permeability to the primary fluid (that is, oil for Oil URM, gas for Gas URM).
- The $x_{f\ total}\sqrt{k}_{SRV(Abs)}$ is calculated based on $x_{f\ total}\sqrt{k}_{SRV}$, using the relation between effective and absolute permeability: $k_{SRV} = k_{SRV(Abs)} k_{rx}(S_{xi})$ where $k_{rx}(S_{xi})$ is a relative permeability of the primary fluid at initial saturation.
- The time to reach the end of linear flow (t_{elf}) is determined from the position of the t_{elf} line on the Square Root Time plot.
- The OOIP / OGIP displayed is related to the area used.
- The EUR and RR come from the boundary-dominated flow Forecast plot.
- When using URM to initialize a numerical model, a default value of 1,000 is used for F_{CD} , if the field is blank.

Calculations		
Model Type	Hz - Multi Frac - SRV	
$A_c k_{SRV}^{1/2}$	1307290.985	md ^{1/2} ft ²
$A_c k_{SRV(Abs)}^{1/2}$	1960936.478	md ^{1/2} ft ²
$x_f \text{ total } k_{SRV}^{1/2}$	3268.227	md ^{1/2} ft
$x_f \text{ total } k_{SRV(Abs)}^{1/2}$	4902.341	md ^{1/2} ft
F_{CD}	0.8	
L_e	15000.0	ft
n_f	15	
k_{SRV}	0.3603	md
$k_{SRV(Abs)}$	0.8106	md
x_f	363	ft
A_c	2.18e+06	ft ²
t_{eff}	67	d
OOIP	9881.4	Mstb
EUR ₀	9.997	Mstb
N_p	0.700	Mstb
RR ₀	9.297	Mstb
R^2	0.688	

Additional parameters depend on the Model Type you select:

- **Vertical - Single Frac** — if you type a value for k_{SRV} , x_f is calculated based on it.
- **Hz - Multi Frac - Effective k** — the stimulated region is treated as a region of higher effective permeability, and the observed linear flow is interpreted as flow towards the wellbore. Therefore, the linear flow parameter obtained from the slope of the analysis line is interpreted as: $A_c \sqrt{k_{SRV}} = 2 L_e h \sqrt{k_e}$. If you type a value for L_e , k_e is calculated.
- **Hz - Multi Frac - SRV** — this model considers bi-wing fractures extending from the horizontal well, and the area of the stimulated region is based on the FMB interpretation. If you type a value for L_e and n_f , x_f is calculated based on the area ($A_{SRV} = 2 L_e x_f$). Then, k_{SRV} is calculated based on $x_f (x_f \text{ total } \sqrt{k_{SRV}} = n_f x_f \sqrt{k_{SRV}})$.

Note: None of the inputs in the Calculations section are required, but the inputs provide additional information about the model used for forecasting.

Primary toolbar

The primary toolbar is located in the Unconventional Reservoir pane and has these icons:

-  **Apply Defaults** — copies [parameters](#) ¹ from the Properties editor or other IHS Reservoir worksheets.
-  **Change Top Left View** — select a plot to be displayed in the top left of your dashboard.
-  **Change Top Right View** — select a plot to be displayed in the top right of your dashboard.
-  **Change Bottom Left View** — select a plot to be displayed in the lower left of your dashboard.
-  **Change Bottom Right View** — select a plot to be displayed in the lower right of your dashboard.
-  **Float a New View** — select a plot to be displayed in a new floating window.
-  **Save or Erase Default Dashboard** — select either save (to save your current dashboard configuration as the default setting), or reset (to reset the dashboard to its original settings).
-  **Show / Hide Disabled Points** — toggle between showing / hiding disabled points on your plot.

For a description of common toolbar icons, see [toolbars](#).

Plot dashboard

The plot dashboard displays your four favorite plots.

Note: For the FMB plot on the dashboard, the OGIP is anchored to the x-axis as a pivot point, and you can move the y-axis intercept by clicking-and dragging the green square. The anchored point on the x-axis is dictated by the t_{eif} line on the Square Root / Superposition Time plot.

¹These parameters can be copied from one unconventional analysis to another: -fracture height min & max -model type (fracture mode) -changing properties options: geomechanical, changing oil saturation, use pseudo-time -material balance options: adsorption, geomechanical -superposition time options: (superposition time type) -forecast parameters: b, qf -typecurve options: raw derivative status, derivative status

Plot toolbar

The icons displayed in the plot toolbar vary depending on the type of plot that you have displayed. The important icons are described below.

-  **Reset Plot Attributes** — resets your plot attributes to its original settings.
-  **Single Annotation** — adds an annotation arrow to the data point you click.
-  **Linked Annotations** — synchronizes your annotation arrows across unconventional reservoir plots. For example, if you move your annotation on one plot using the keyboard arrow keys, the arrow is synchronized on the other plots. The values vary as you move from the displayed date for one date / time row in the Production editor to the other.
-  **Data Filter** — opens the [Data Filter dialog box](#) where you can apply a data filter. For more information, see [saturated filter](#).
-  **Boundary Dominated Curve** — applies a boundary-dominated curve to your plot.
-  **Typecurve Options** — opens the Typecurve Options dialog box where you can toggle the Raw Data Derivative and Beta Derivative options, as well as select your derivative type (Standard, Bourdet, or Difference) and derivative cycles. For bilinear flow, the beta-derivative is 0.25; for linear flow, it is 0.5; for boundary-dominated flow, it is 1.0.

For a description of common plot icons, see [plot toolbars](#).

Unconventional reservoir plots

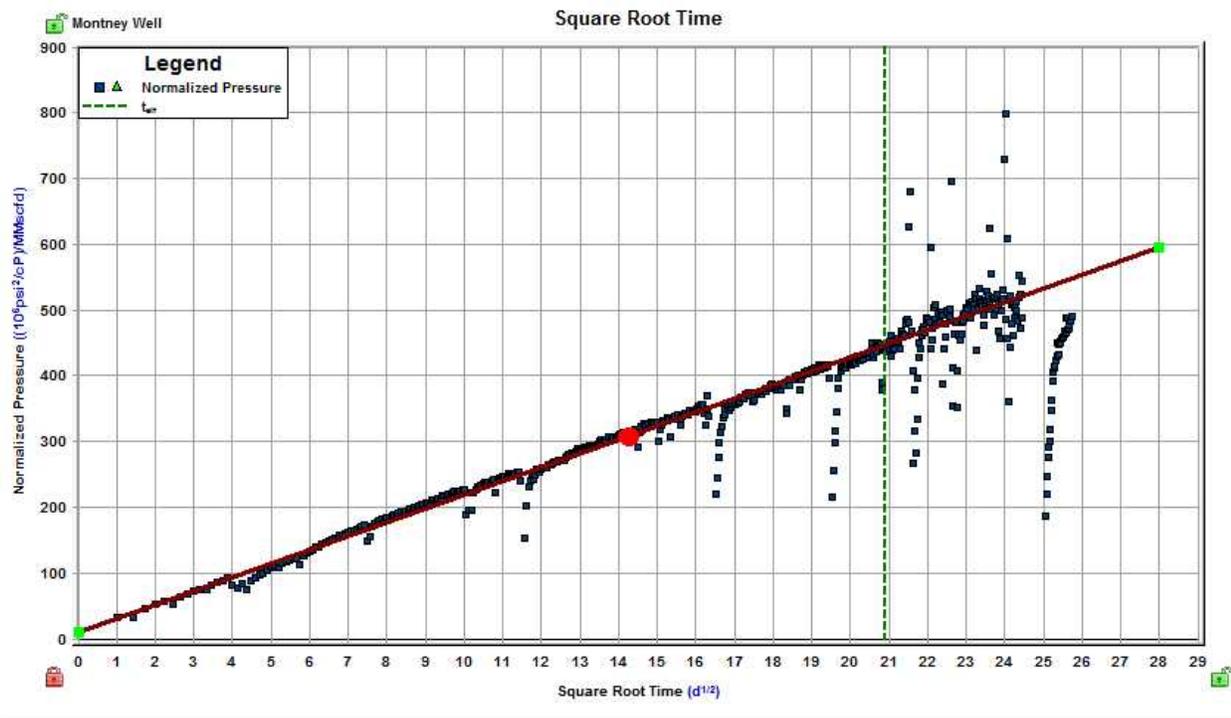
Unconventional reservoir plots include the following:

- [Square Root Time](#)
- [Flowing Material Balance](#)
- [Typecurve](#)
- [Forecast](#)
- [Schematic](#)
- [Allowable Ax vs Ad Region](#)
- [Fourth Root Time](#)

All of these plots can be sent to the comparison plot in the [Results Viewer](#) by right-clicking the plot and selecting **Send to Comparison Plot**. For more information, see [comparison plot](#).

Square root time

This plot displays normalized pressure vs square-root time, and displays an automatic best fit of the data. The slope of the best fit line is used to determine the $x\sqrt{k}$, while the y-intercept is used to determine the apparent skin or apparent fracture conductivity.



Note: On constant / variable pressure worksheets, Harmony Enterprise can calculate "b" according to your adjustments, if you click the **Boundary Dominated Curve** icon (📏), and move the red analysis line on the plot manually.

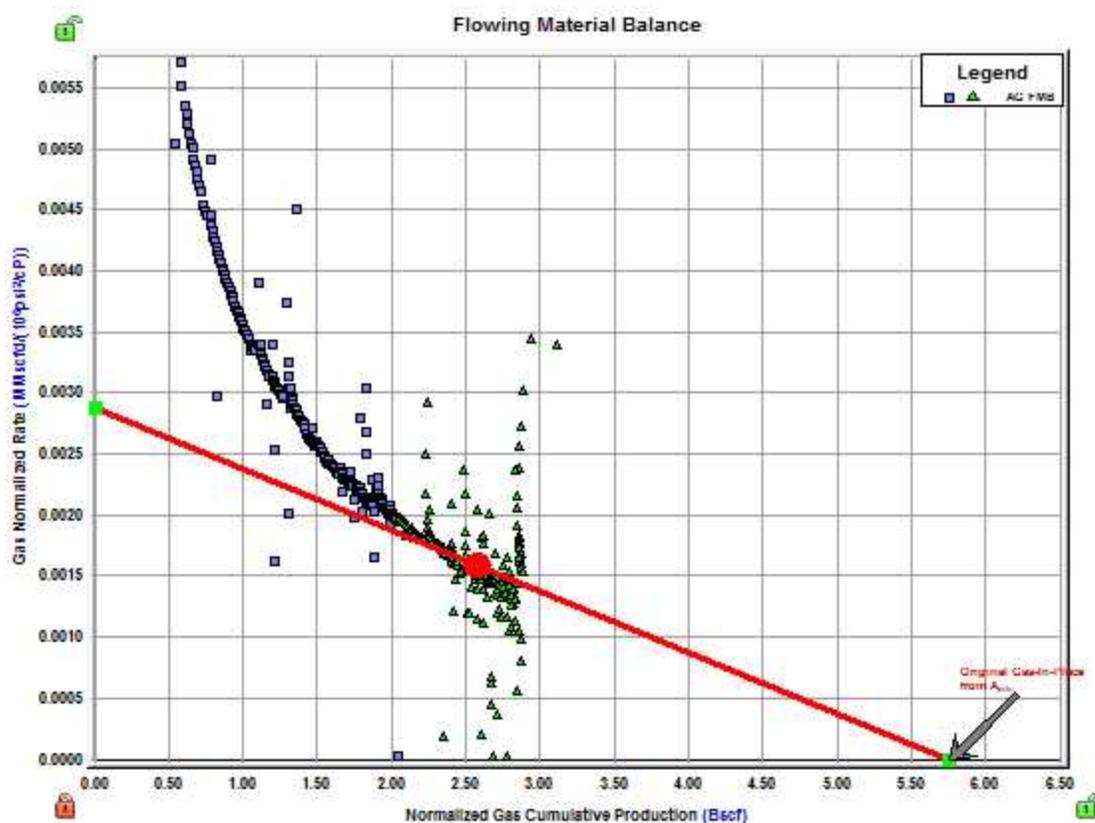
Line manipulation

The best-fit line for this plot has the following properties:

- The line has an infinite length to the right.
- The line always has a manipulation point on the left-side on the y-axis.
- The line translates up and down when dragged by the left point.
- You can rotate the line around the center point by dragging the line itself.

Flowing material balance (FMB)

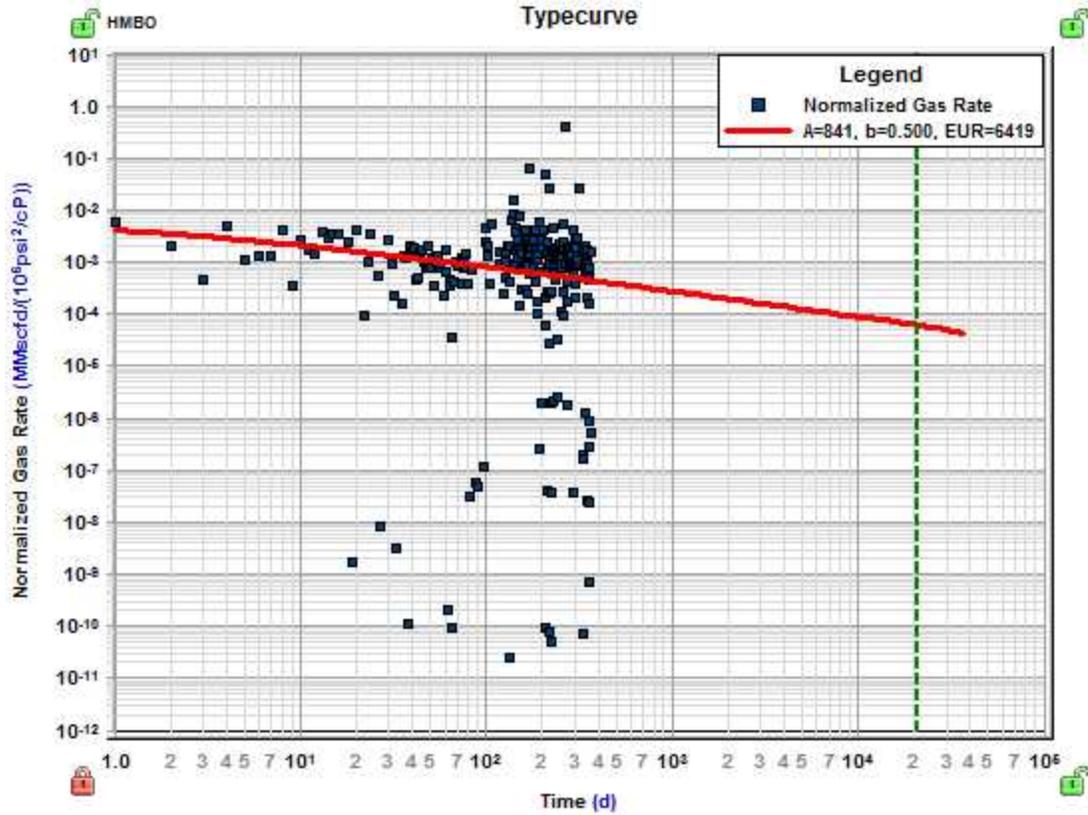
This plot shows the OOIP / OGIP, as well as the area of the stimulated reservoir volume (SRV). In addition, this plot displays an automatic best fit of the data.



Note: By default, the flowing pressure to be used in the analysis is populated from the last portion of pressure data in the production history.

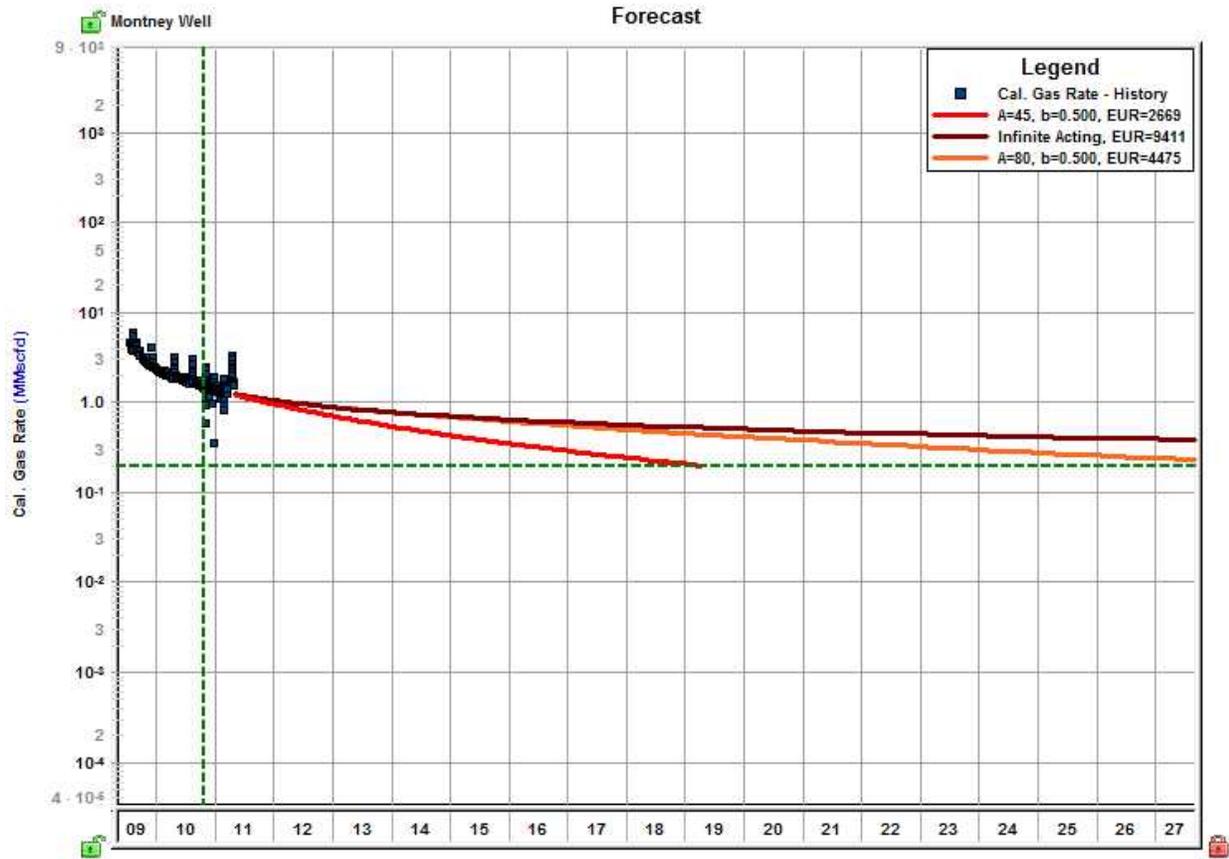
Typecurve

This plot indicates the flow regime. The red line indicates infinite-acting linear reservoir behavior; the green line indicates bounded reservoir behavior.



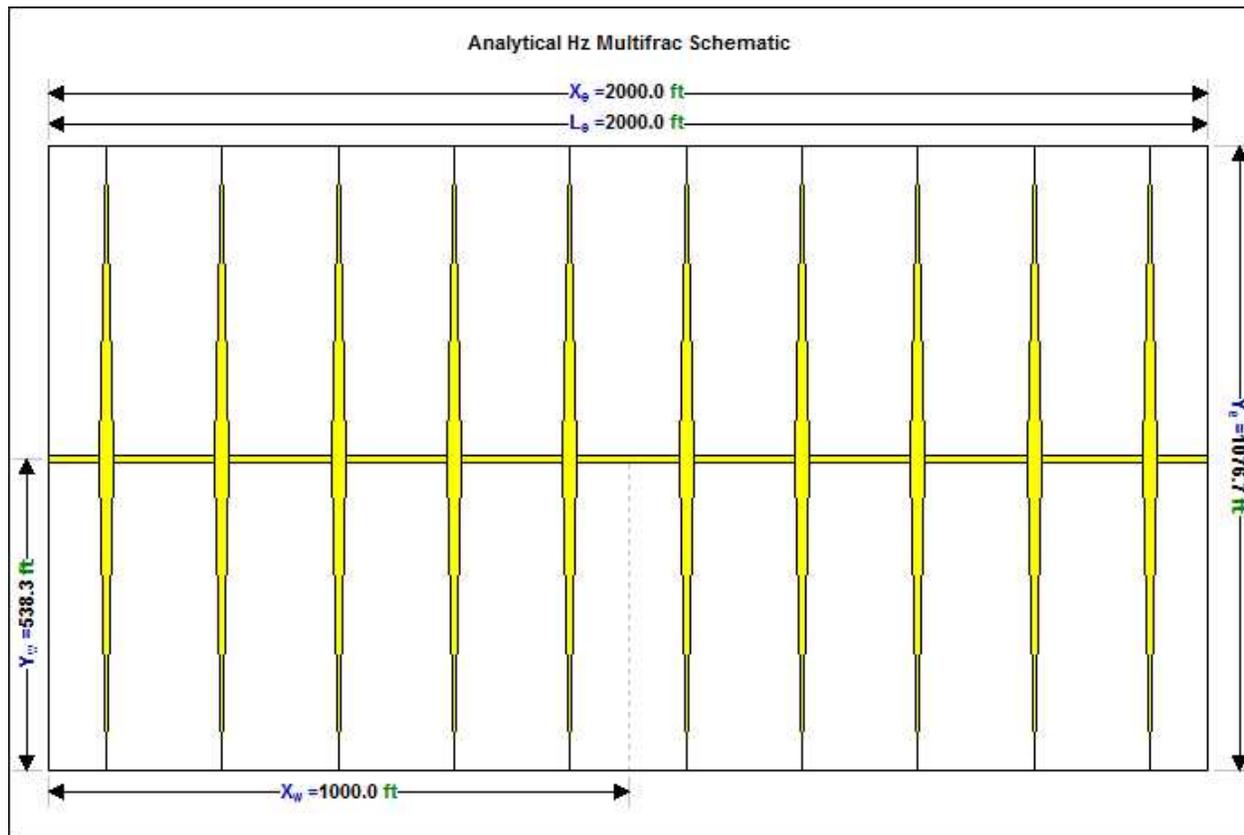
Forecast

This plot displays the forecast rate. The red line indicates infinite-acting linear reservoir behavior; the green line indicates bounded reservoir behavior.



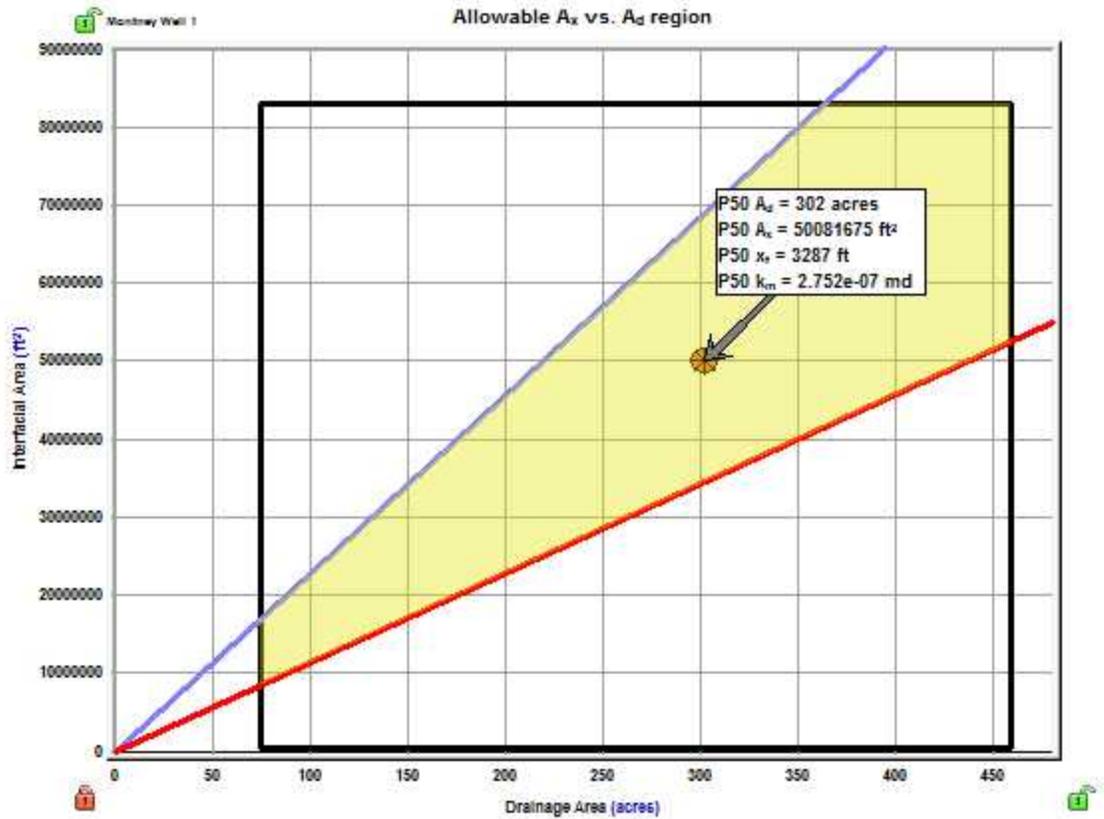
Schematic

In the "most likely" model, the schematic is based on the most likely SRV configuration on the Allowable A_d vs A_x Region plot. In the deterministic model, the schematic is based on the parameters you have entered.



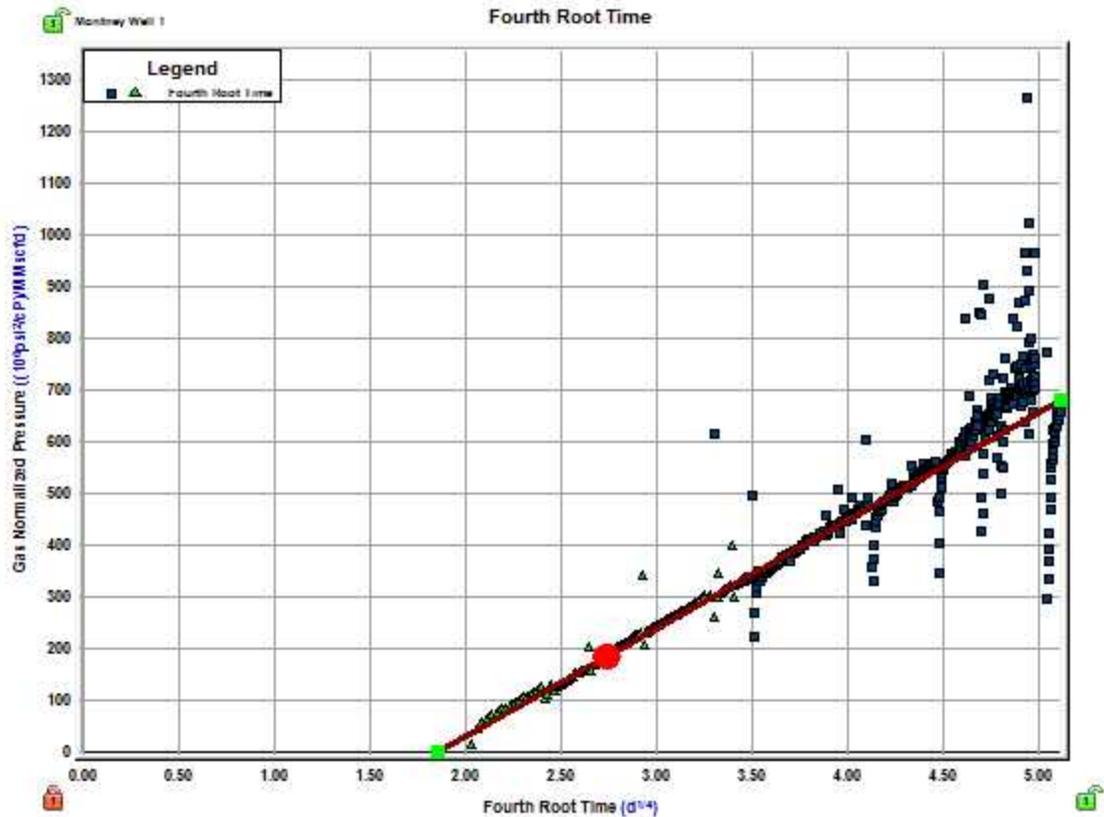
Allowable A_x vs A_d region

This plot defines a region that contains the full set of possible SRV configurations. The point at the center of the mass is used as the "most likely" values. (This plot is only available in the Most Likely model.)



Fourth root time

This plot displays normalized pressure vs fourth-root time, and displays an automatic best fit of the data, as well as calculating values based on bilinear flow equations.

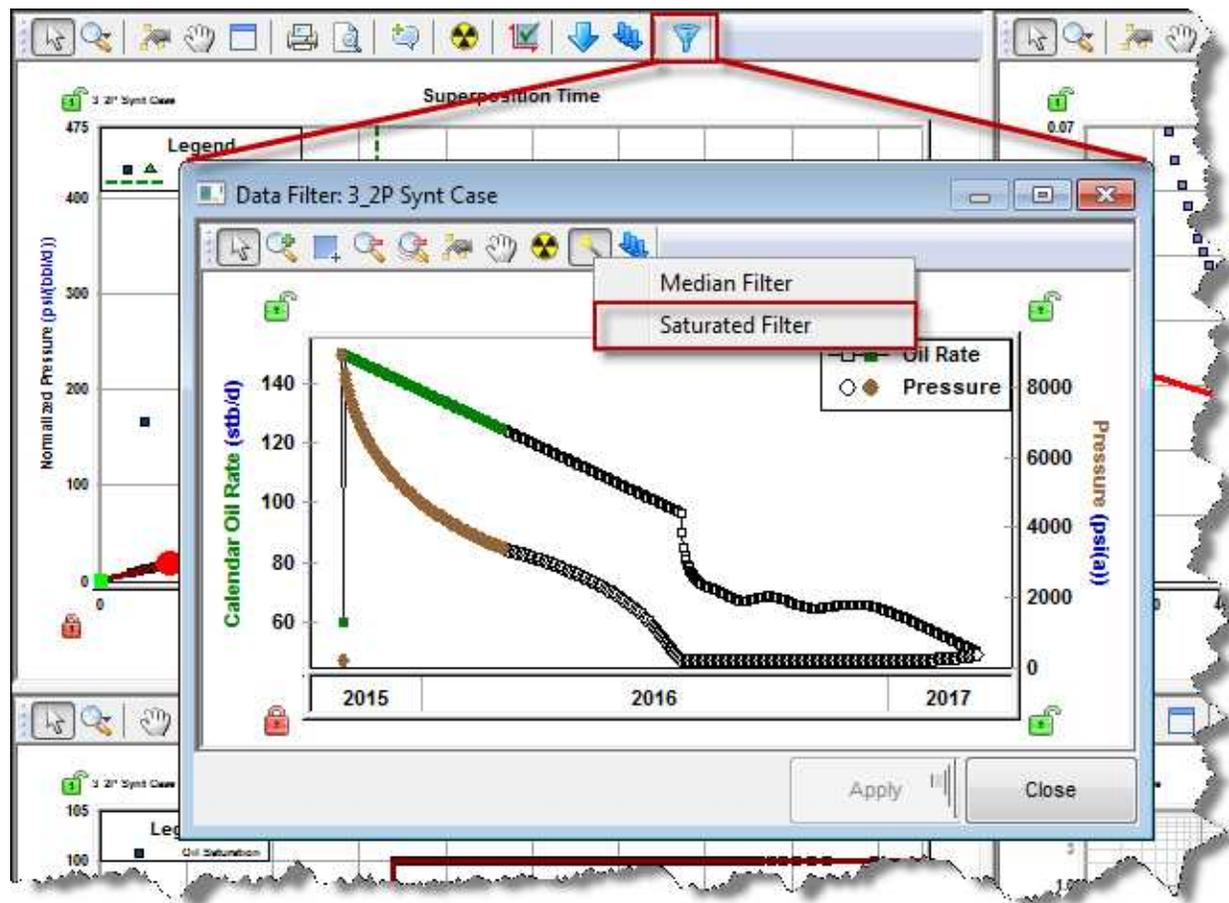


Saturated filter

The unconventional reservoir module (URM) analysis is a single-phase analysis; therefore you should be cautious when applying it to cases where a well exhibits two-phase flow. For oil wells, we can expect two-phase flow after the flowing pressure drops below the oil bubble point pressure. The Saturated Filter option can be used to identify the portion of the data where flowing pressure is below the bubble point pressure (oil and gas flowing in the reservoir).

To use this option:

Click the **Data Filter** icon on a Square Root Time or FMB plot; then click the **Fully Automatic** icon on the Data Filter plot.



Note: The saturated filter uses the oil bubble point pressure set in the Properties editor; therefore, it is important to set it accurately.

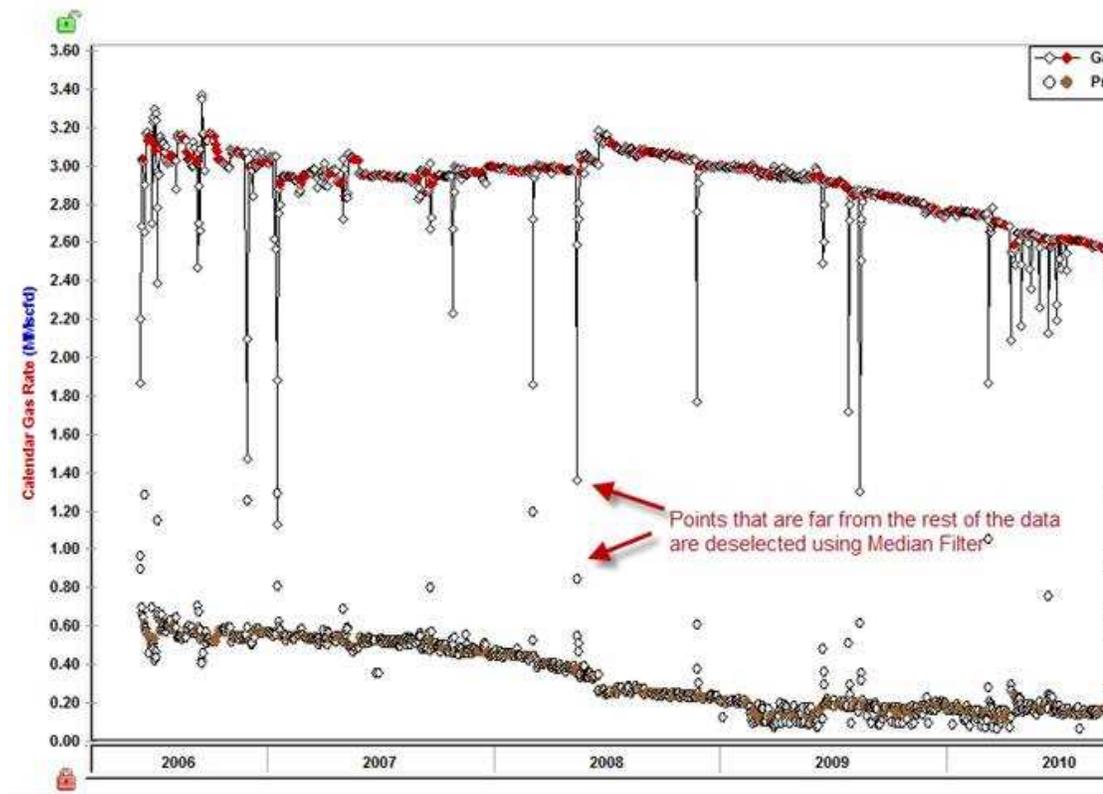
Data Filter dialog box

This dialog box is commonly used when you click the filter data for an FMB, typecurve, numerical URM, or unconventional reservoir analysis.

This dialog box has the following important icons:

- **Tools to Select Data Points for Filtering**  — opens an additional toolbar with point-selection options.
 - **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.

- **select all data points** — selects all the data points on the plot.
- **deselect all data points** — deselects all the data points on the plot.
- **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.
- **Fully Automatic**  — select one of these options:
 - **Median Filter** — used to make data less noisy by deselecting data points that are far from the rest of the data (those points are likely to be outliers). Note that the dataset needs to have at least 20 points for this filter to be applicable.



- **Saturated Filter** — used to identify the portion of the data where flowing pressure is below the bubble point pressure (oil and gas flowing in the reservoir). For more information, see [saturated filter](#).

For information on common plot icons, see [plot toolbars](#).

Volumetrics analysis

The volumetrics analysis is used to estimate the original hydrocarbon fluid volume in a reservoir. This analysis requires knowledge of reservoir rock properties, as well as fluid saturations and properties. A volumetric analysis can be conducted at any point in the production history, but it is most often used early in the life of the reservoir. For more information, see [volumetrics theory](#).

Note: This analysis works with your Harmony Forecast™ license.

Toolbars

For information on the primary toolbar (and context menu), see the [Analysis Manager](#).

The secondary toolbar is located in the analysis tab and includes the following important icon:

 **Defaults** — copies parameters from the [Properties editor](#).

For information on common icons, see [plot toolbars](#).

Parameters

Enter (or edit) the parameters in the worksheet. As values are calculated, the summary values in the Analysis Manager are also populated.

- **Reservoir Properties** — these parameters are pre-populated from the Properties editor. However, you can amend parameters to see how variation in reservoir properties affects results. To re-populate all of the parameters from the Properties editor, click the **Defaults** icon (). To re-populate a specific parameter from the Properties editor, click the **Defaults and Limits** button () to the right of the parameter.
- **Oil / Gas Properties** — these parameters are pre-populated from the Properties editor, but you can change some of them. Volumetric calculations use the properties specified in the volumetric analyses.
- **Formation Volume Factor** — you can enter a formation volume factor (B_{gi} or B_{oi}), or click the checkbox to let Harmony Enterprise automatically calculate this value.
- **Adsorption** (intended for shale gas) — you can enter adsorption values to calculate $OGIP_A$. (The default values are those set in the Adsorption section of the Properties editor.)

- **Volume Parameters** — Since reservoir area, rock volume, pore volume, and hydrocarbon pore volume are all linked to each other, OFIP can be calculated based on any of these inputs. Click the option  for the parameter you want to enter.
You can also set Dimensions (reservoir length x_e and reservoir width y_e). In this case, the reservoir area is calculated based on given dimensions, and this area is used to calculate the remaining volume parameters.
Or, you can calculate OFIP based on the RF and EUR, by clicking the EUR option .
- In a gas analysis, a surface loss parameter (SL) is available. When SL is entered, the Sales EUR parameter is calculated (if EUR_g exists).

Note: The gas volume analysis has different parameters depending on whether the well is a dry / wet gas well, or a liquid-rich gas well. In the case of a liquid-rich gas well, a volumetric analysis calculates and displays $OGIP_d$ (original dry gas-in-place), as well as $OGIP_r$ (original recombined gas-in-place). Additionally, OCIP (original condensate-in place) is calculated. When displaying volumetric analysis results in the Results Viewer, gas summary parameters ($OGIP$, EUR_g , Gp_{Net} , RR_g , and RF_g) are displayed in terms of dry gas, *not* in terms of recombined gas. For more information on calculations for liquid-rich gas wells, see volumetrics theory.

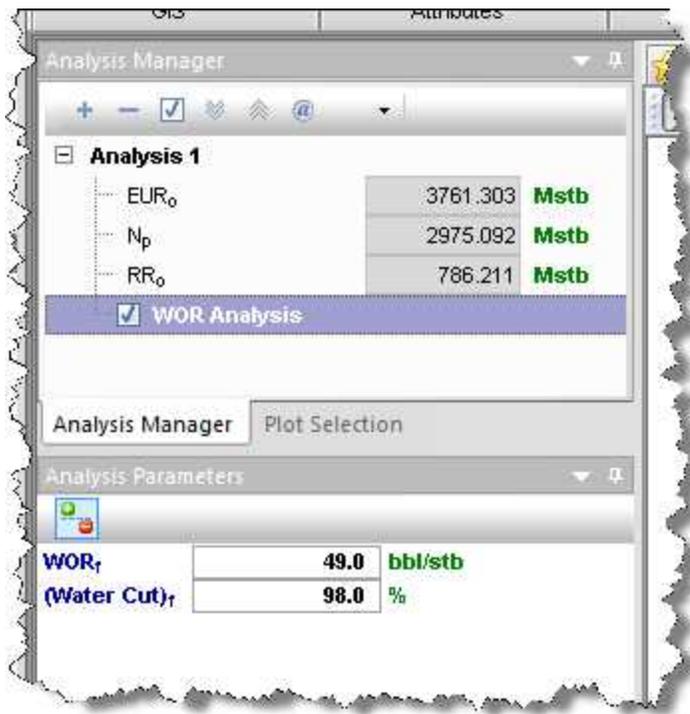
WOR analysis

The water-oil ratio (WOR) analysis is an empirical method for trending water and oil production. For additional information on theory and concepts, see WOR forecasting theory. When a WOR analysis is added, it is initialized using a best fit.

Note: This analysis works with your Harmony Forecast™ license.

Analysis Parameters pane

A WOR analysis can be added or displayed in an open worksheet while Cumulative Oil is on the x-axis, and at least one of the following is on the y-axis: WOR, WOR+1, or Water Cut. After you add a WOR analysis (see analyzing an entity), the selected analysis has its detailed parameters displayed in the Analysis Parameters pane.



In this pane, you can specify / view the following parameters:

- **WOR_f** — the final / abandonment water-oil ratio. It is initialized from the settings defined in the Options dialog box (see [WOR options](#)). This value is calculated when **(Water Cut)_f** is specified, and this value must be in the range (0, ∞).
- **(Water Cut)_f** — the final / abandonment water cut. It is initialized from the settings defined in the Options dialog box (see [WOR options](#)). This value is calculated when **WOR_f** is specified, and the value must be in the range (0, 100).

Analysis Parameters toolbar

The Analysis Parameters toolbar has the following icon:

-  **Show / Hide Results Line** — shows (default setting) or hides the dashed-green line on the plot that represents the abandonment for the WOR analysis. It is initialized from the settings defined in the Options dialog box (see [WOR options](#)).

Line manipulation

Line manipulations are initiated by clicking-and-dragging:

- **Line** — changes the slope of the trend line about the manipulation point.
- **Manipulation point** () — translates the line vertically or horizontally while maintaining the slope.

Analysis line customization

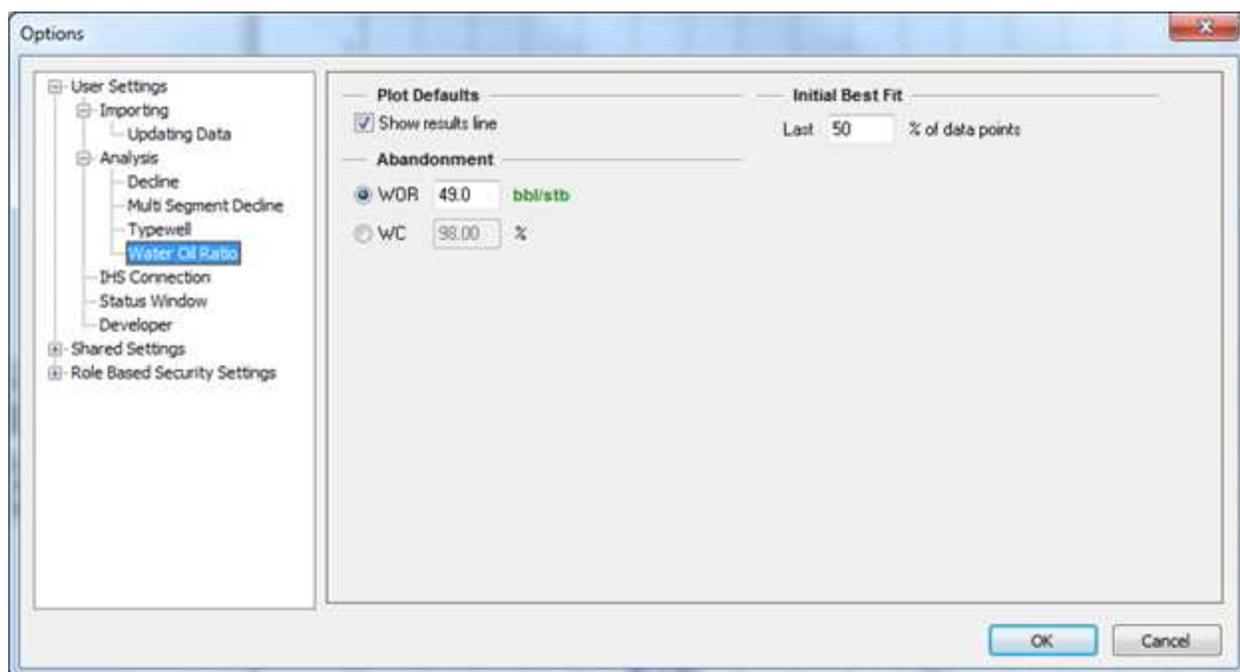
To change the line width and color of your analysis line, right-click the WOR analysis line and select **Customize Line**.



After you customize your line, the modifications are saved and applied to every worksheet that displays this analysis.

WOR options

WOR analysis options are accessed by clicking the **Options** icon () on the main toolbar, or by clicking the **Tools** menu and selecting **Options**. In the Options dialog box, click **Water Oil Ratio** under the User Settings>>Analysis node.



You can set the parameters that initialize water-oil ratio (WOR) analyses in Harmony Enterprise. These inputs can be overridden with each analysis, and the Options dialog box inputs are only used when the analysis is created. The WOR parameters and settings are as follows:

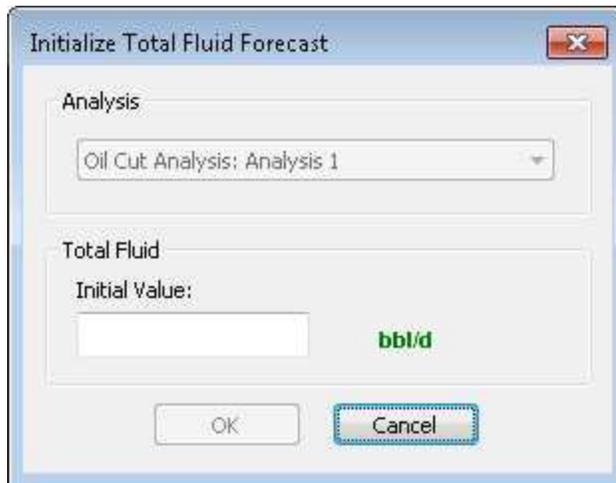
- **Show results line** — shows / hides the green-dashed line for abandonment on your plot.
- **WOR** — sets the abandonment WOR. Harmony Enterprise uses 49 bbl/stb as the default.
- **WC** — sets the abandonment water cut (WC). Harmony Enterprise uses 98% as the default.
- **Initial Best Fit** — specifies the percentage of your historical data that you want to be included in the initial best fit.

WOR / oil cut forecast

By associating a water-oil ratio (WOR) / oil cut forecast (total fluid forecast) with a WOR or oil cut analysis, Harmony Enterprise calculates oil and water forecasts that update as the WOR / oil cut analysis is modified.

Note: This forecast works with your Harmony Forecast™ license.

You can add this analysis by selecting a WOR or Oil Cut analysis while on a Forecast worksheet, or by selecting **WOR / Oil Cut Forecast** from the Analysis Manager after clicking the + icon. Using either method opens the Initialize Total Fluid Forecast dialog box.

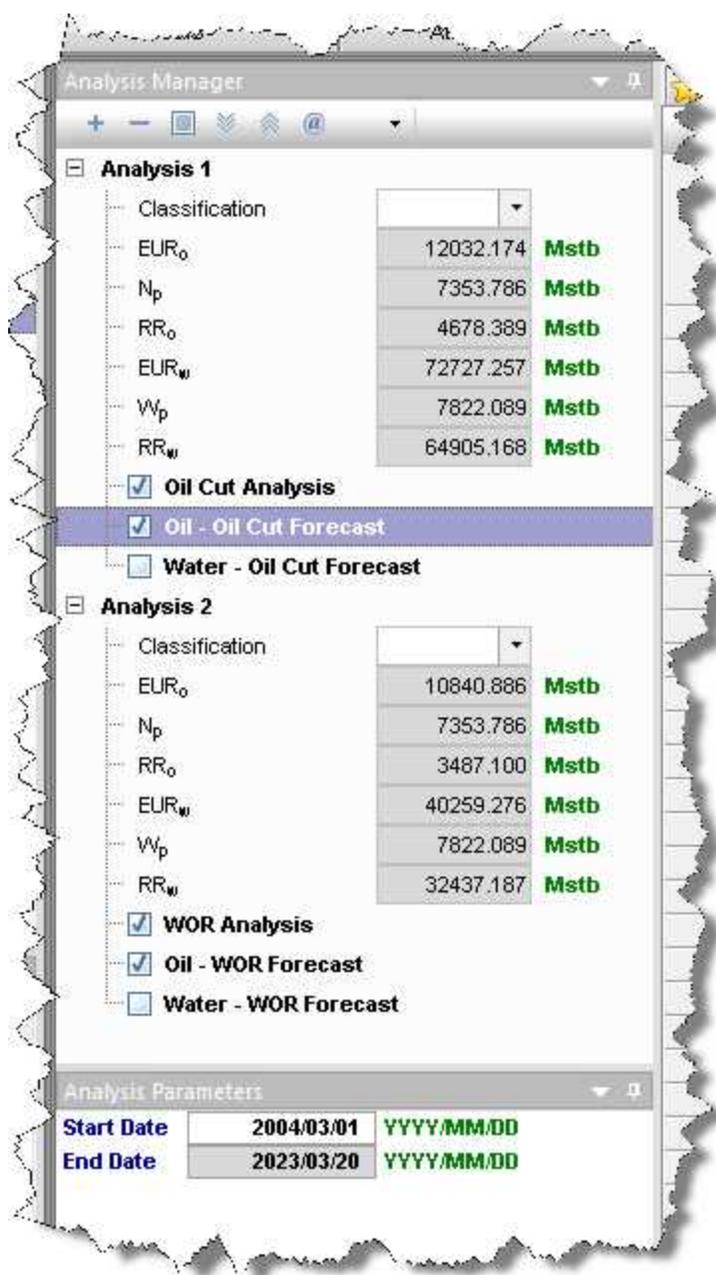


- **Analysis** — select the WOR or oil cut analysis to be used with the total fluid forecast.
- **Total Fluid Initial Value** — the specified value is a constant to initialize the total fluid forecast ($q_o + q_w$). The total fluid rate can be defined through time by entering values in the $q_{\text{Liquid}(o+w)}$ column in the Forecast worksheet.

Clicking **OK** after providing the required inputs, adds an oil and water forecast with the specified analysis, starting at the end of historical production.

Analysis Parameters pane

After you add a WOR / Oil Cut Forecast, selecting the oil or water forecast displays its detailed parameters in the Analysis Parameters pane.



In this pane, you can specify / view the following parameters:

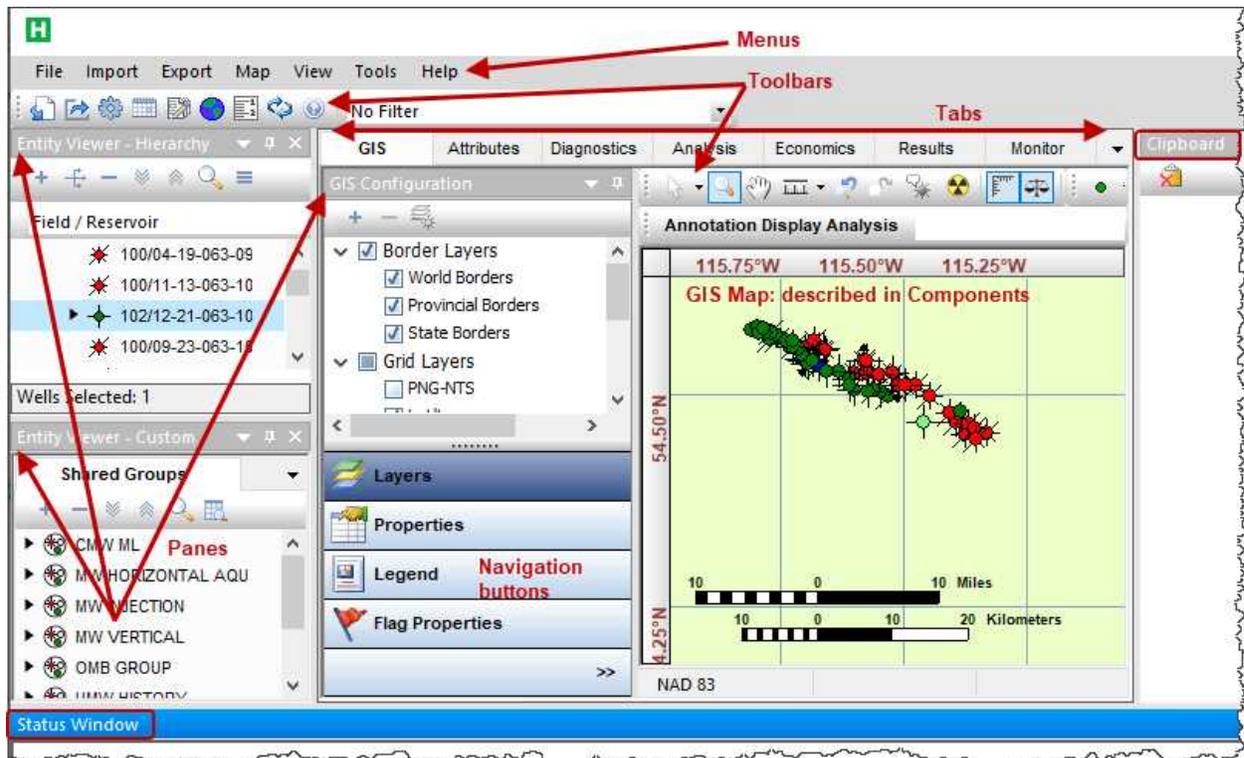
- **Start Date** — the start of the total fluid forecast. It is initialized as the end of historical production. Specifying a value beyond the end of production does not adjust the trend of the associated WOR / Oil Cut analysis.
- **End Date** — the date at abandonment controlled by the associated WOR / Oil Cut analysis (WOR_f, (Water Cut)_f, or (Oil Cut)_f).

Navigation

Harmony Enterprise navigation consists of the following:

- [Clipboard](#)
- [Menus](#)
- [Panels](#)
- [Selecting entities](#)
- [Status Window](#)
- [Tabs](#)
- [Toolbars](#)

This screenshot outlines the main elements in the Harmony Enterprise interface. For a description of more technical elements in the interface, see [Components](#).



Clipboard

With the clipboard, you can copy and paste data, including analyses, between entities, or within a single entity.

The clipboard supports:

- Decline analyses
- Analytical models
- Unconventional reservoir analyses
- Properties editor
- Wellbore editor
- Multi-well models

The clipboard also supports bulk pasting properties to a selection of wells. After selecting wells in the Entity Viewer, click the **Context Menu** (☰) icon in the toolbar to select content from the clipboard. Or, you can drag a clipboard item to one of the selected wells and paste the copied properties to the entire selection.

When you copy data to the clipboard, the Clipboard docking window opens, and data is displayed within the pane as a button.



To rename content in the clipboard, right-click the item you want to rename.

To delete content from the clipboard, click the **Delete** icon (🗑️) in the toolbar, or right-click and select from the context menu.

To copy wellbore configurations to the clipboard, two options are available:

- copy full configuration
- copy without depths — often useful for copying between wells as the depths of tubing, casing, etc. are specific to each well. You can use this option to copy diameters of pipe, flow path, and correlation without the depths of the source configuration.

To paste content to a new well or analysis, click the **Paste** icon () , but ensure that the correct item is selected in the clipboard.

Menus

Harmony Enterprise has the following menus.

File

Close Data Source Connection — closes your data source connection, but keeps the Harmony Enterprise window open.

Exit — closes Harmony Enterprise.

Import

Database Connection — imports well data from a database.

Enerdeq / IHDC — imports / updates your Harmony Enterprise project with data from Enerdeq or IHDC. For more information, see import from Enerdeq.

PowerTools — opens the PowerTools File import dialog box where you browse to your PowerTools file and historical Enerdeq data (optional).

.hldb file — imports data from a local database (by default, a local database is created when Harmony Enterprise is installed) extracted from Harmony Enterprise. For more information, see importing from Harmony Enterprise. (You can import a single file, or you can bulk import multiple files in the Browse dialog box.) Note that this functionality does *not* apply to SE licenses.

Piper Forecasts — opens the Well Selection and Piper Forecast Import dialog box where you can update your selected wells, or update all wells, with your Piper forecasts (.fdb files). Note that your existing analyses are never overwritten.

WellTest — opens the Import dialog box where you browse to your WellTest file.

Kingdom XML — opens the Import dialog box to select your Kingdom XML file. This provides well properties mapped from a Kingdom project.

File — imports well data from a file.

Export

Production Data, Forecasts, or Decline Analyses — opens an [export wizard](#) where you select your production data, forecasts, or decline analyses.

To .hldb file — browse to the location for your .hldb file. you can export a portion of the data from an existing Harmony Enterprise project to create a new project. This function can be used for breaking a master project into smaller files (which you can merge at a later date), or for sending a portion of the data in your project to technical support. The following data is available for extracting: entities and their attributes, custom attributes, production, custom datasets, worksheets, analyses, reference dates, wellbore data, wellbore configurations (if none exist), and numerical models.

To Piper — opens the [Piper Export wizard](#), which guides you through exporting entities, and entity-and-analysis pairs for use in Piper®.

To WellTest — browse to the location where you want to save your .hmexp file. For more information, see [export to WellTest](#).

To Analytics Explorer — opens the Analytics connector. If you do not have Spotfire installed, an error message pops up. For more information, see [Analytics Explorer](#).

Map

Last Opened Session — opens the map you last used.

Open Saved Map — browse to your saved Spatial Explorer map.

New Map — opens a new Spatial Explorer map.

For more information, see [Spatial Explorer](#).

View

Toolbars and Docking Windows — select the toolbars and docking windows you want to display.

Toggle Units — switches between metric and field (imperial) units.

Tools

Import Templates / Workflows — imports an .hrmtemplate file. After browsing to your file, you select from the following options:

- **Discard existing** — deletes your existing templates / workflows.
- **Keep existing, and discard imported duplicates** — keeps your existing templates / workflows, and when there are duplicate templates / workflows being imported, they are not imported.
- **Keep existing, and append imported duplicates** — keeps your existing templates / workflows, and when duplicates exist, additional templates / workflows are created (for example, <filename>1, <filename>2, and so on).
- **Keep existing, and overwrite existing duplicates** — keeps your existing templates / workflows, and overwrites existing templates / workflows when duplicate templates / workflows are imported.

Export Templates / Workflows — exports an .hrmtemplate file of your templates and workflows.

Tip: Templates and workflows are user-specific. Therefore, any templates or workflows you create are not seen by other users in a multi-user environment.

Options — opens the [Options dialog box](#).

Help

Web Help — opens the Harmony Enterprise help system. Note that an Internet connection is required.

Release Notes — opens the Release Notes topic.

Licensing — *(only visible after you connect to a data source)* opens the [Licensing dialog box](#) where you can request and release licenses.

Error Report Directory — *(only visible after you connect to a data source)* opens File Explorer and the location where log files are saved.

Note: The Licensing and Error Report Directory menu options are viewable after you open a Harmony Enterprise project or file (that is, these menu options are not viewable from the [startup screen](#)).

Customer Support — opens the [Customer Care web page](#).

Getting Started Videos — opens the [Learning Center](#) for Harmony Enterprise.

Tips and Tricks — opens the [Learning Center](#) for engineering software.

Technical Resources — opens the [Energy Resources web page](#), where you can view technical videos, published papers, and unconventional energy maps.

Engineering Webcasts — opens the [Engineering web page](#), where you can register to view helpful videos.

Product Alerts Opt-In — opens the [IHS Markit Energy Event Opt-In web page](#), where you can select the products you want to get alerts for.

Training — opens the [Harmony Enterprise Training page](#).

Reset Docking Panes — *(only visible from the [startup screen](#))* closes Harmony Enterprise and resets your docking panes to the original settings.

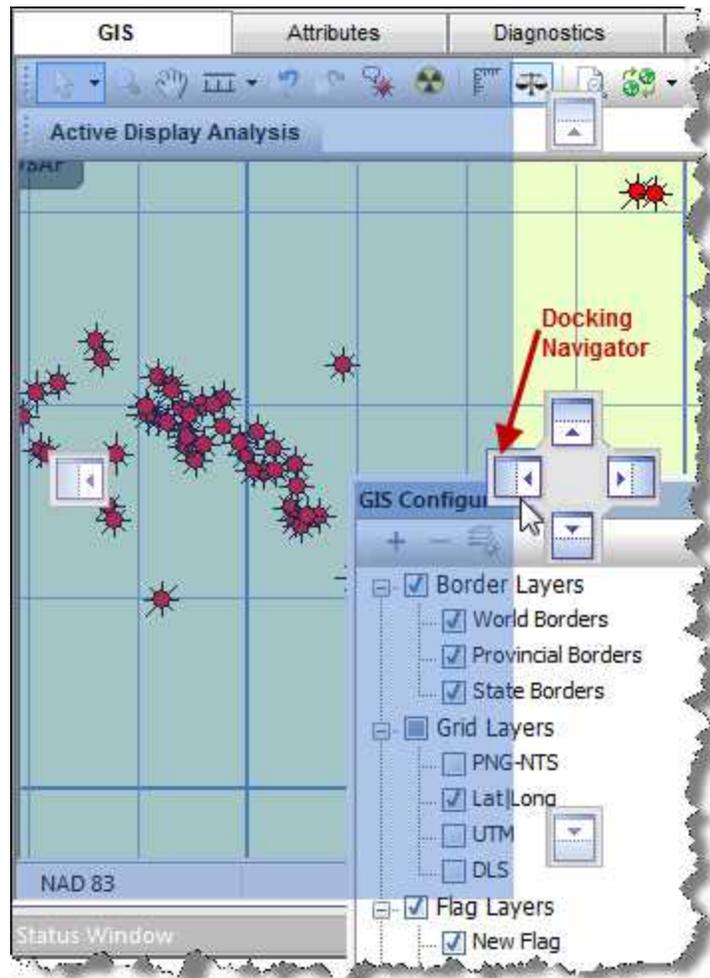
Defrag HLDB — *(only visible from the [startup screen](#))* opens a dialog box where you select an .hldb file for compacting (to reduce the file size), and defragging (to improve the file's performance).

Panes

Panes are windows in Harmony Enterprise that contain specific groups of data. Panes include the Entity Viewer – Hierarchy pane, the Entity Viewer - Custom pane, the Clipboard, the Status Window, and all of the data windows inside the tabs. You can move panes to a variety of positions to suit your needs.

Docking functionality

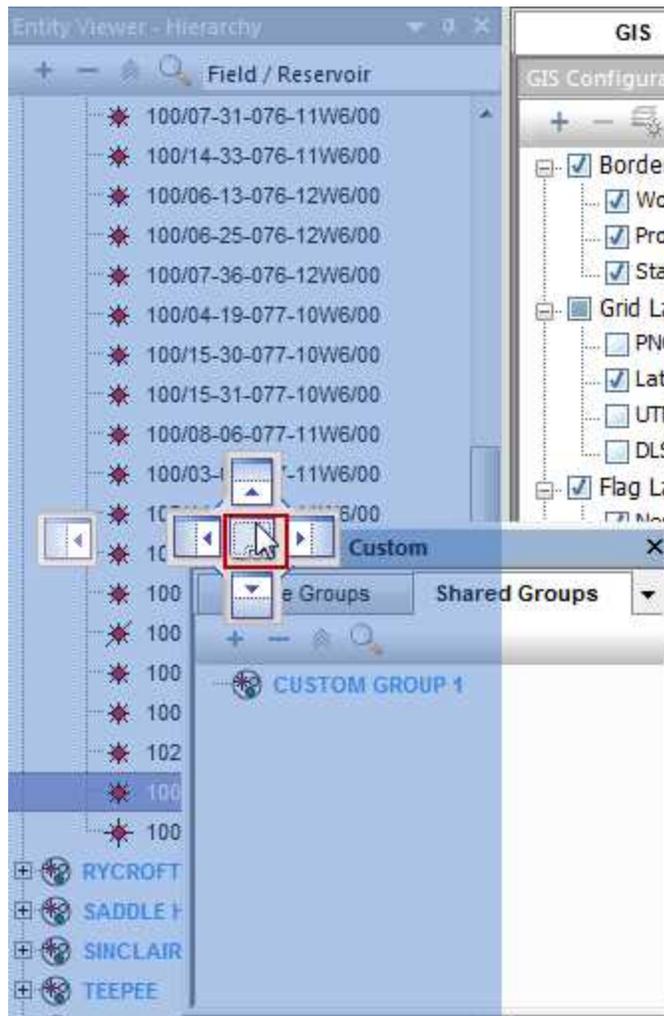
When you click-and-drag the pane's title bar, the docking navigator is displayed.



You can dock the pane in these positions:

- top, bottom, left, and right of the application's window
- in a tabbed view

To dock the pane in a tabbed view, hover over the center box and release. Note that you cannot use a tabbed view with non-docking panes.

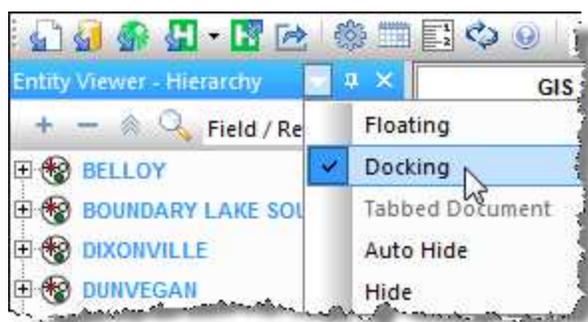


To undock the pane, click-and-drag the tab to a new location.

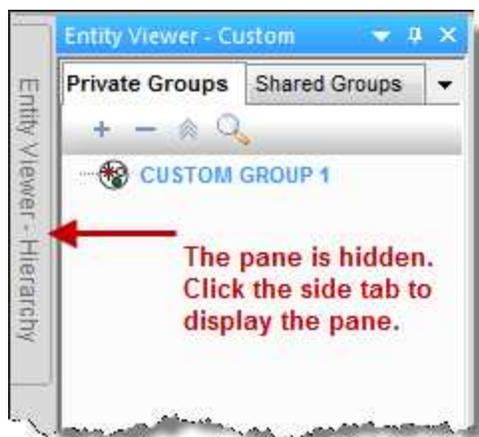
Note: If you need to reset your docked panes to the original settings, see [resetting docking panes](#).

Pane options

When you right-click the pane's title bar, you can select various options from the context menu.



- **Floating** — detaches the pane from the main window. You can move the pane to your preferred location, including outside the application's window.
- **Docking** — returns the pane to its last-docked position.
You can also double-click the pane's title bar to float / dock the pane.
- **Auto Hide** — moves the pane to a tabbed position on the left-side of the application.

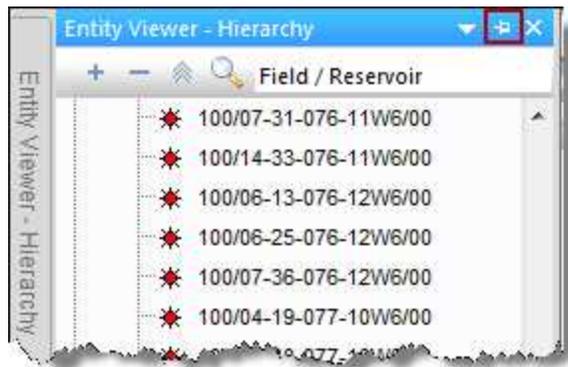


- **Hide** — this option is only applicable for the Clipboard and the Status Window. If you select this option, the pane is hidden. To display a hidden pane, click the **View** menu and select **Toolbars and Docking Windows, Clipboard or Status Window**.

Pin functionality

If you click the **Pin** icon (📌) in the pane's title bar, the pane moves to a tabbed position on the left-side of the application.

To return the pane to a docked position, click the sideways pin icon.



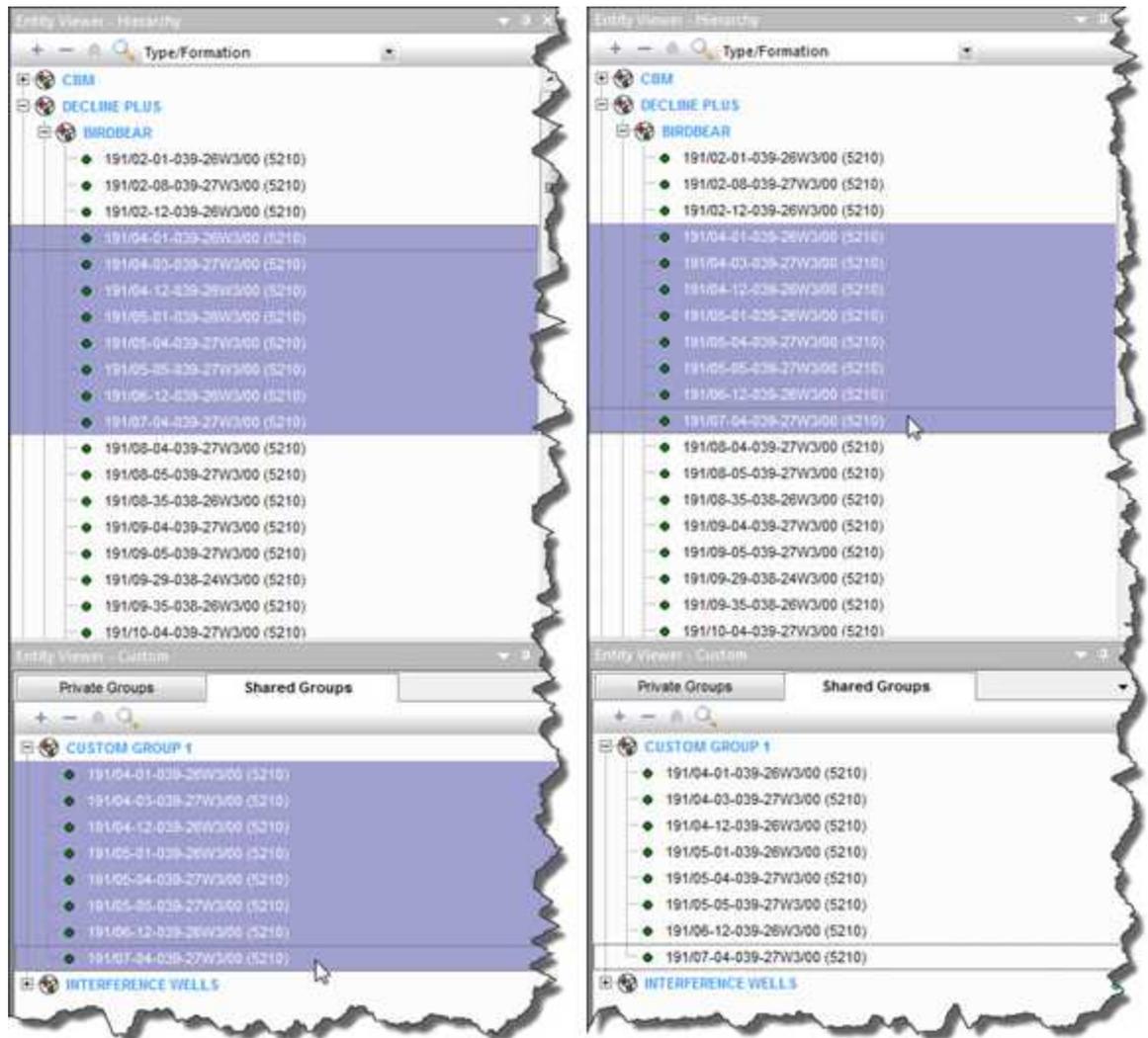
Selecting entities

You can select entities in a variety of ways. For example, you can select entities from the:

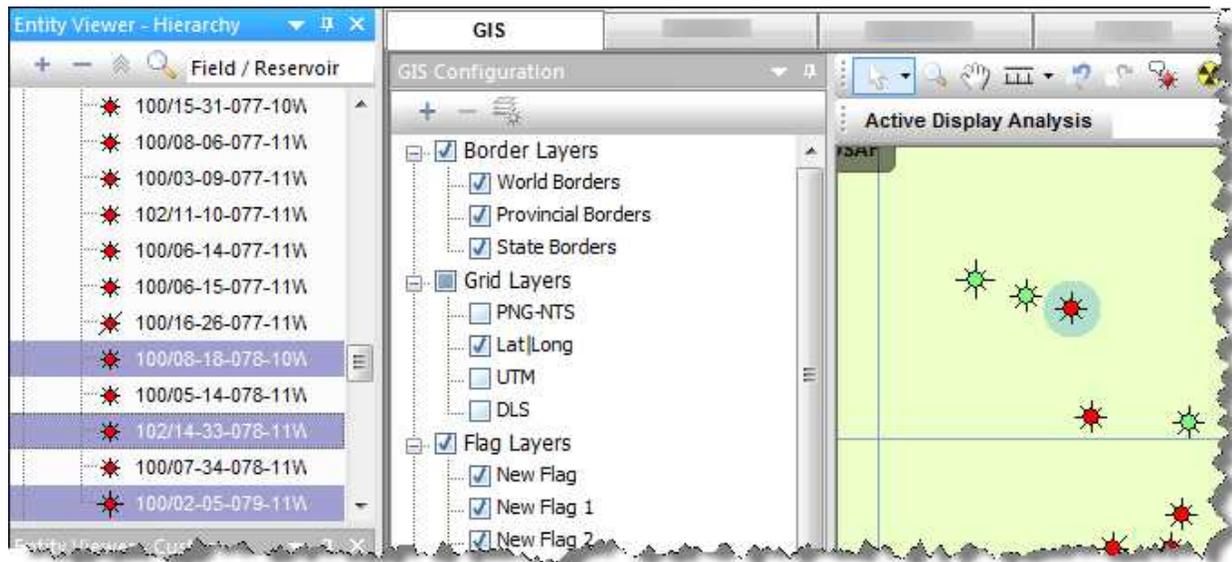
- [GIS map](#)
- [Entity Viewer - Hierarchy pane](#)
- [Entity Viewer - Custom pane](#)

There is a direct connection between the Entity Viewers (Hierarchy pane and Custom pane) and the tabs. Wells and groups listed in the entity viewers can be selected by clicking them in the Hierarchy pane or Custom pane. You can select multiple entities by clicking wells while holding down the **Ctrl** key (to make individual selections), or the **Shift** key (to make group selections).

Wells that are selected in the Custom pane are automatically selected in the Hierarchy pane. However, if a well is originally selected in the Hierarchy pane, it is not automatically selected in the Custom pane. Also, a selection of a custom groups cannot be made simultaneously with an additional selection of individual wells in the Hierarchy pane.

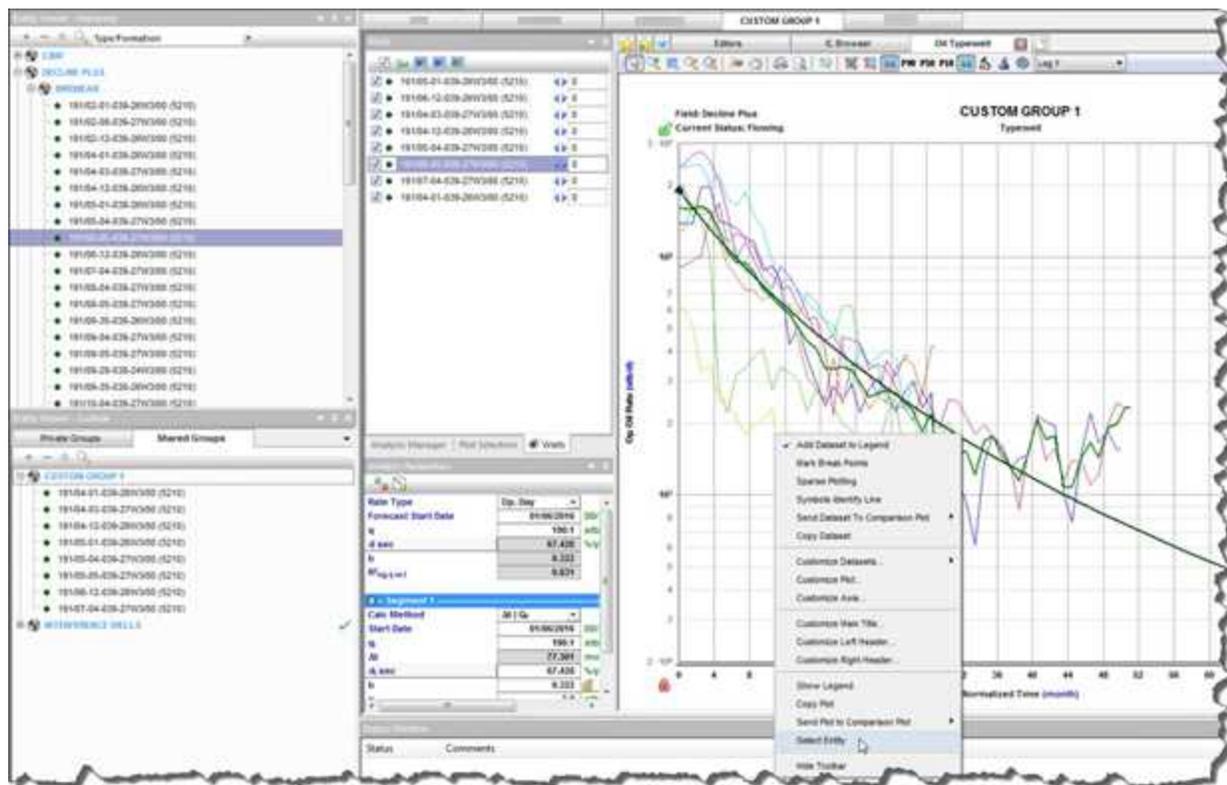


Entities displayed on the GIS map can be selected by clicking them on the map (GIS tab). For example, when a well is selected, it turns light green. When one or more entities are selected in the GIS tab, the same entities are selected in the Hierarchy pane. Multiple entities can be selected in the GIS tab by pressing the **Ctrl** key while clicking entities on the map.



Multiple selections can be further refined by using the Select Subset option on the Attributes tab and Results tab.

You can also adjust your entity selection on the Analysis tab, using the typewell worksheet, but only a single entity can be selected from the Typewell worksheet. This entity must be a member of the group that the typewell analysis is being applied to, and the selection is only displayed in the Hierarchy pane. You can select this entity by right-clicking an individual well's dataset in the Typewell plot and selecting **Select Entity**. You can also select wells using their analysis lines.



Tip: You can also use your keyboard's arrow keys to change your selections. (This can be useful when, for example, you preview data on the [Diagnostics tab](#).)

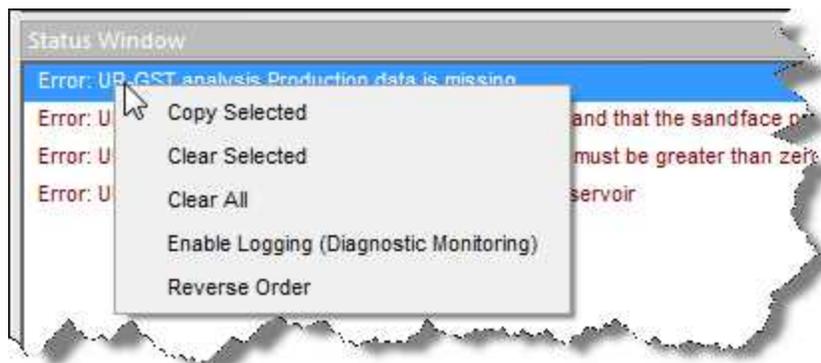
Status Window

By default, the Status Window is docked at the bottom of Harmony Enterprise's content pane. The Status Window displays short descriptive messages pertaining to the current state of the project, or the results of actions as you perform them. Scenario names are used in the Status Window.

Note: To hide or show the Status Window, click the **View** menu, **Toolbars and Docking Windows, Status Window**.

Status Window options

When you right-click a message in the Status Window you can select various options from the context menu.



- **Copy Selected** — copies the selected message to the clipboard.
- **Clear Selected** — removes the selected message from the Status Window.
- **Clear All** — removes all messages from the Status Window.
- **Enable / Disable Logging (Diagnostic Monitoring)** — if you enable logging, a text file is saved to your computer's hard drive. This text file logs all of the messages displayed in the Status Window.

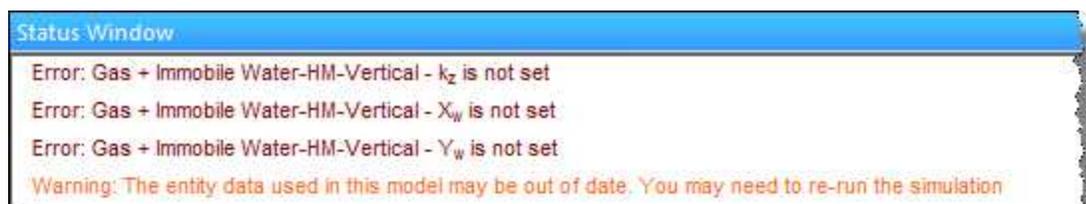
This log file is stored in the following location: \User-s\user permissions in local folders.

- **Reverse Order** — by default, the most recent messages are displayed at the bottom of the Status Window. To reverse this display order, select this option.

Message categories

There are three categories of messages:

1. **Normal** — operations that are running correctly. No action is required.
2. **Warning** — operations that can run, but may give erroneous results due to invalid or missing parameters. Corrective action is likely required.
3. **Error** — operations that cannot be completed. Corrective action is required to resolve the error.

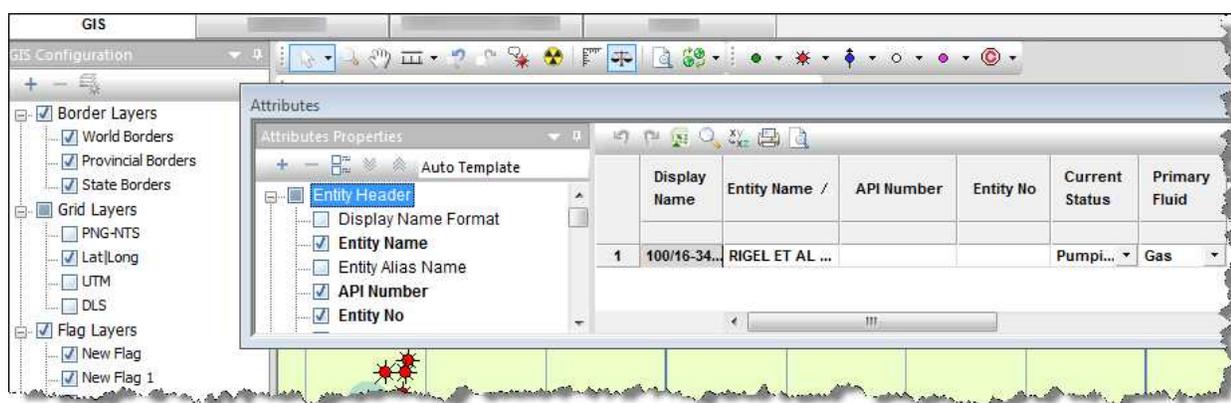


Note: You can double-click some issues to go to the problem area as soon as the issue arises.

Tabs

Tabs are displayed across the top of the Harmony Enterprise window, and can be detached from the application window to facilitate comparing data, especially when comparing multiple entities at the same time.

To float a tabbed window, double-click the tab.



To return a floating tab to its docked position, double-click the tab.

Tip: All of the tabs can float except for the Analysis tab and Diagnostics tab.

Toolbars

Harmony Enterprise has many toolbars. Some toolbars have icons that are specific to a certain toolbar (for example, the [GIS toolbar](#)), while other toolbars have common icons. This topic describes the most common toolbars and related icons.

Main toolbar

The main toolbar has the following icons:

-  **Import** — select from these options:
 -  **Database Connection** — imports data from a database. For more information, see [import well data from a database](#).

-  **Enerdeq / IHDC** — imports / updates your Harmony project with data from Enerdeq or [IHDC](#). For more information, see [import from Enerdeq](#).
-  **PowerTools** — opens the PowerTools File import dialog box where you browse to your PowerTools file and historical Enerdeq data (optional).
-  **.hldb file** — imports data from a local database extracted from Harmony Enterprise. (This functionality does not apply to SE licenses.) For more information, see [import from an .hldb file](#). (You can import a single file, or you can bulk import multiple files in the Browse dialog box.)
-  **Piper Forecasts** — opens the Well Selection and Piper Forecast Import dialog box where you can update your selected wells, or update all wells, with your Piper forecasts (.fdb files).
-  **WellTest** — opens the Import dialog box where you browse to your WellTest file.
-  **Kingdom XML** — — opens the Import dialog box to select your Kingdom XML file. This provides well properties mapped from a Kingdom project.
-  **File** — imports a file. For more information, see [import well data from a file](#)
-  **Export** — select from these options:
 -  **Production Data, Forecasts, or Decline Analyses** — export production data, parameters from decline and multi-segment decline analyses, or export all forecasts. For more information, see [export data](#).
 -  **To .hldb file** — you can export a portion of the data from an existing Harmony Enterprise project to create a new project. This function is useful, for example, for breaking a master project into smaller files (which you can merge at a later date), or for sending a portion of the data in your project to technical support. The following data is available for exporting: entities and their attributes, custom attributes, production, custom datasets, worksheets,

analyses, reference dates (excluding active reference dates), wellbore data, wellbore configurations, and numerical models.

Note: You need to have LocalDB installed in order to export wells. If you attempt to export wells without a local database, an error message is displayed. For more information, see [export to an .hldb file](#).

-  **To Piper** — opens the [Piper Export wizard](#), which guides you through exporting entities, and entity-and-analysis pairs for use in Piper®.
 -  **To WellTest** — export your selected entities to a .hmexp file.
 -  **To Analytics Explorer** — opens the Analytics connector. If you do not have Spotfire installed, an error message pops up. For more information, see [Analytics Explorer](#).
 -  **Options** — opens the [Options dialog box](#), which contains settings for various processes in Harmony Enterprise.
- Any of the User Settings you change are applied after you close the dialog box, and do not impact existing entities. However, Shared Settings are database settings that apply to all entities, both new and old.
-  **Reference Dates** — opens the [Reference Dates dialog box](#) where you can create a new reference date, specify the active reference date, or hide archived reserve analyses.
 -  **Bulk Editor** — opens the [Bulk Editor dialog box](#) where you can delete analyses and worksheets. You must select an entity from the Entity Viewer prior to clicking this icon.
 -  **Map - Spatial Explorer** — opens the [Spatial Explorer submenu](#). For more information, see [Spatial Explorer](#).
 -  **Toggle units** — switches the units displayed between metric and field (imperial).
 -  **Refresh** — reads the most up-to-date information from the data source you are connected to. Click this icon to see / get changes made by other users connected to the same data source.
 -  **Help** — opens the online help.

- **Project Filter** — click the drop-down list to select a filter you previously created, modify a filter, or select no filter (the default setting). For more information, see [project filters](#).

Plot toolbars

Different plots have different icons available on their toolbars. The most common icons are listed below:

-  **Set Mouse to Default** — switches the cursor to its default state. When the cursor is in its default state, you can hover over any dataset displayed on the plot to read its values on the tooltip.
-  **Display a toolbar with options to zoom** — opens an additional toolbar with zooming options:
 -  **Point Zoom** — click a data point to zoom in 50%.
 -  **Rectangular Zoom** — click-and-drag a rectangle around the area you want to zoom into.
 -  **Undo last zoom** — undo your latest zoom.
 -  **Undo all zooms** — resets the plot display to your original view.
-  **Pan Data** — switches the cursor to a Pan Data state. When the cursor is in this state, you can pan the x- and/or y-axes by clicking-and-dragging within the plot or the desired axis.
-  **Print** — opens the Print dialog box.
-  **Print Preview** — opens the Plot (Preview) window where you can adjust how your plot prints.
-  **Create Annotation** — opens the Create Annotation dialog box. Select your type of annotation from the **Attach To** drop-down list:
 - **screen** — attaches your annotation to a fixed area on the screen. This annotation retains its position, if you rescale your axes.

- **plot** — attaches your annotation to a fixed area on the plot. This annotation moves with the plot, if you rescale your axes.
- **data** — (default setting) attaches your annotation to an x- and y-data point. If you use your keyboard arrow keys, you can move your annotation along the dataset and view the coordinate values of each plotted point. This annotation moves with the data point, if you rescale your axes.
-  /  **Toggle the Autoscaling Option for the Plot** — switches automatic scaling on and off. When automatic scaling is on (the icon is in the  state), the plot scales adjust to fit all the data whenever the data is modified. When automatic scaling is off (the icon is in the  state), the plot scales remain unchanged whenever the data is modified.
-  **Rescale all axes** — adjusts the minimum and maximum of the x- and y-axes to fit all data within the plot.
-  **Display a toolbar with options to select data points** — opens an additional toolbar with point-selection options for best-fitting your analysis. These icons are described from left-to-right.



- **spray gun** — selects points when you left-click, and deselects points when you right-click. The mouse wheel can be used to change the spread-tool's size.
- **select all data points** — selects all the data points on the plot.
- **deselect all data points** — deselects all the data points on the plot.
- **lasso** — select points by clicking-and-dragging a shape around your data points. Deselect points by right-clicking-and-dragging a shape around the data points you do not want.

-  **Maximize / Restore Window** — if the plot is a part of a dashboard, the Maximize / Restore window switches between displaying just one plot and displaying all plots on the dashboard.
-  **Add a diagnostic line** — adds a diagnostic line to your plot, which can be useful for identifying and extrapolating trends in the data.
-  **Reset Scaling** — resets your plot attributes to default settings.
- **Plot options drop-down list** — select your options (for example, coordinate, log). Note that your plot options vary depending on the type of plot you select.

Pane toolbars

Different panes have different icons available on their toolbars. The most common icons are listed below:

-  **Add / Remove** — adds / removes objects displayed on the pane.
-  **Expand All / Collapse All** — expands / collapses all nodes of the tree structure displayed on the pane.
-  **Deselect all series / Select all series** — deselects / selects all of the items in the tree structure.
-  **Import** — imports data related to the pane.
-  **Undo** — undo changes to data inputs, series display selections, and column-specific unit and precision changes.
-  **Redo** — redo changes that have been undone.
-  **Export to Excel** — create a *.csv file of the data displayed in the table.

Table toolbars

Different tables have different icons available on their toolbars. The most common icons are listed below:

-  **Print** — opens the Print dialog box.
-  **Print Preview** — opens the Grid (Preview) window where you can adjust how your table prints.
-  **Export to Excel** — saves your table data to a .csv file.

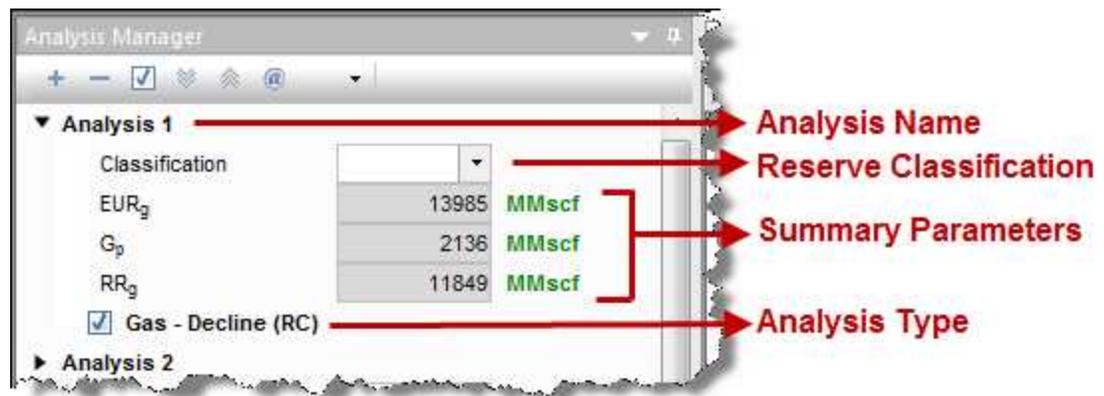
Components

Harmony Enterprise components / modules include the following:

- Analysis Manager
- Entity Viewer - Hierarchy
- Results tab
 - Results Viewer - Grid View
 - Results Viewer - Plot View
 - Comparison Plot
 - Reporting
 - Bulk modify decline analyses
- Analysis tab
- Analytics Explorer
- Attributes tab
- Best-fitting functionality
- Bulk Editor dialog box
- Database connection
- Diagnostics tab
- Economics
- Editors
- Entity Viewer - Custom
- GIS
- Import functionality
- Monitor tab
- Options dialog box
- Piper export
- Plots
- Plot Selection pane
- Project filters
- Query Wells dialog box
- Reference Dates dialog box
- Role-based security
- Scenarios
- Spatial Explorer
- Tables / grids
- Well layers
- Worksheets

Analysis Manager

The Analysis Manager opens each time you create a new Harmony Forecast worksheet, or open an existing worksheet. Within the Analysis Manager, you can display and manage the analyses on an open worksheet.



Within the Analysis Manager pane is a tree structure that displays all of the existing analyses. If you want to rename an analysis, use the ... button and select the Rename option. Under each analysis:

- You can set your reserve classification from the **Classification** drop-down list, but this requires an active reference date. For more information, see Reference Dates dialog box.
- A summary of analysis results are displayed, showing the estimated ultimate recovery (*EUR*), historical cumulative production at the forecast start date (*G_p* or *N_p*), and remaining recoverable (*RR*) for the fluid in the analysis.
- You can select / deselect the analysis type to show / hide the analysis on the worksheet. After you select an analysis, a list of detailed parameters pertaining to that analysis is displayed in the Analysis Parameters pane below the Analysis Manager pane. Within the Analysis Parameters pane you can view and modify your parameters.
- If you created a probabilistic numerical analysis, you can toggle the P10, P50, and P90 forecasts on or off.
- If you imported a Piper® Forecast, it is displayed with a "- Piper Forecast" suffix (for example, Gas - Piper Forecast, Oil - Piper Forecast, or Water - Piper Forecast) in the Forecast worksheet.

Toolbar

This toolbar has the following icons:

- **+ Add Analysis** — adds an analysis to the current entity with the type specified. You can add these types of analysis:
 - Arps decline
 - Forecast Consolidation
 - Oil Cut Ratio Analysis

- Multi-segment decline
- Stretched Exponential decline
- Probabilistic decline (beta)
- Duong decline
- Ratio Forecast
- WOR / Oil Cut Forecast
- Custom Forecast
- WOR Analysis
- Ratio Trend

Note that the analysis you are adding to a worksheet needs to be compatible with the selected entity for analysis, fluid type, and the worksheet itself. Harmony Enterprise does not restrict analyses based on the primary fluid of a well, but there are two restrictions:

- the entity type has to support the analysis (depending on whether the entity is a hierarchy group, custom group, or well).
 - the worksheet has to support the analysis (to add a gas decline, the plot has to contain cal / op gas rate vs time, normalized time, or cumulative gas).
-  **Remove Analysis** — deletes the currently selected analysis.
 -  **Select All / Deselect All** — selects / deselects all of the analyses in the Analysis Manager.
 -  **Expand All / Collapse All** — expands / collapses all nodes of the tree structure displayed in the pane.
 -  **Reference Volume** — updates the cumulative production at the reference date for all classified analyses associated with the active reference date.

For a description of common icons, see [toolbars](#).

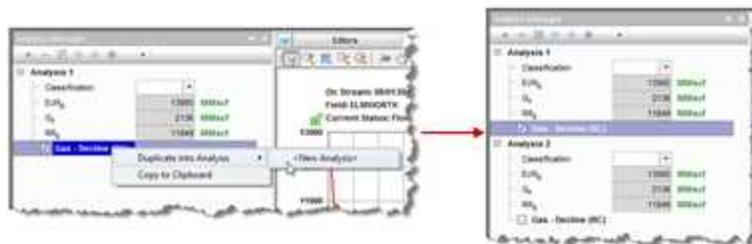
Analysis type menu

Clicking the ... button for an analysis type within the Analysis Manager lists these options:

Move — moves the analysis to the destination you select. To move an analysis:

- Click the ... button for the analysis type and select **Move to**, and then select a destination:
 - <New Analysis> — appears as a new analysis in the Analysis Manager, at the bottom of the pane. Note that if the current Analysis Name has only

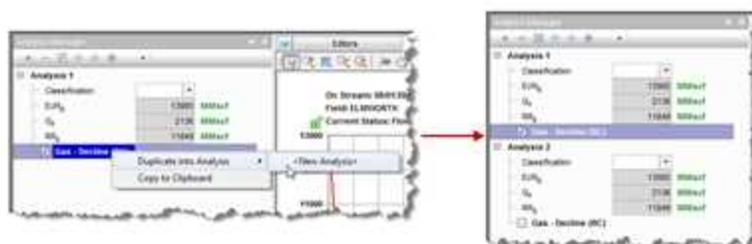
one analysis type, this option is not available.



<Analysis Name> — links the analysis to a selected analysis. If this was the only analysis type under the Analysis Name, the original Analysis Name is removed.

Copy to — moves a copy of the analysis to the destination you select, while retaining the original analysis in the Analysis Manager. To copy an analysis:

- Click the ... button for the analysis type and select **Copy to**, and then select a destination:
 - **<New Analysis>** — lists the copy as a new analysis in the Analysis Manager, at the bottom of the pane.



- **[Analysis Name]** — links a copy of the analysis to a selected analysis, while maintaining the original analysis.

The linked analyses can only associate a single forecast type (for example, decline or ratio) per fluid type. For example, you cannot link a multi-segment gas decline with any other type of gas decline. Neither can you link two WOR ratio analyses. However, you may:

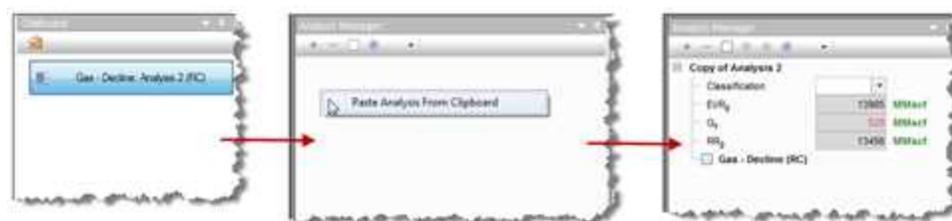
- *copy* an oil decline into a gas decline analysis (or vice versa). The results of both analyses are displayed under the parent analysis name in the Analysis Manager.
- *copy* an oil decline analysis into a WOR analysis. The decline results always overwrite the ratio analysis results. This is a permanent action, and removing

links does not restore the results of the WOR analysis.



Copy to Clipboard — you can copy a decline or multi-segment decline analysis into the clipboard and paste it into the Analysis Manager of another entity. To copy an analysis to other entities:

- Click the ... button for the analysis type and select **Copy to Clipboard**.
The Clipboard pane opens.
- Drag the copied analysis from the Clipboard to the Analysis Manager of another entity.
Or, right-click the empty space in the Analysis Manager and select **Paste Analysis from Clipboard**.



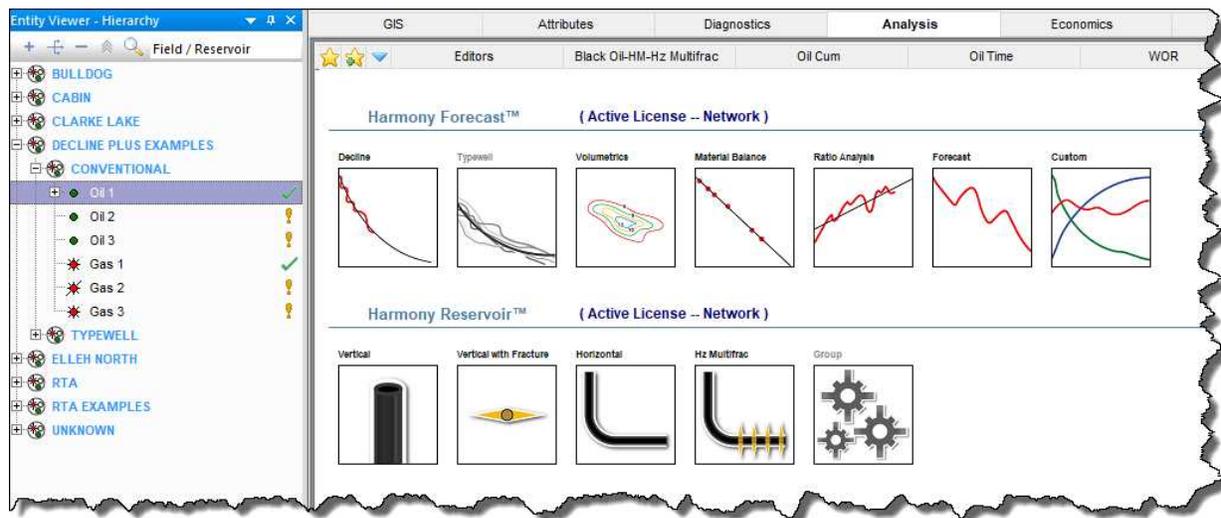
Delete — deletes the analysis.

Note: Instead of clicking the button, you can right-click an analysis name to access the same options.

Analysis tab

The Analysis tab displays your analyses. If you click this tab without first selecting an entity, you are prompted to do so.

After you have selected an entity and clicked this tab, you can select your worksheet. For more information, see selecting an entity for analysis.



Tip: You can only display a single well, scenario, or group in this tab. Since a Typewell worksheet is used to display multiple decline analyses, it is grayed-out.

After you have selected an entity for analysis, that entity is locked until you select another entity. In other words, the lock is released when you click another entity. If another user tries to open the same entity for analysis while the lock is in place, a message is displayed in the main pane and the Status Window. There is no way to force the release of the well, but the username with the locked well is displayed in the Status Window.

Note: The editors are also locked when you are performing an analysis.

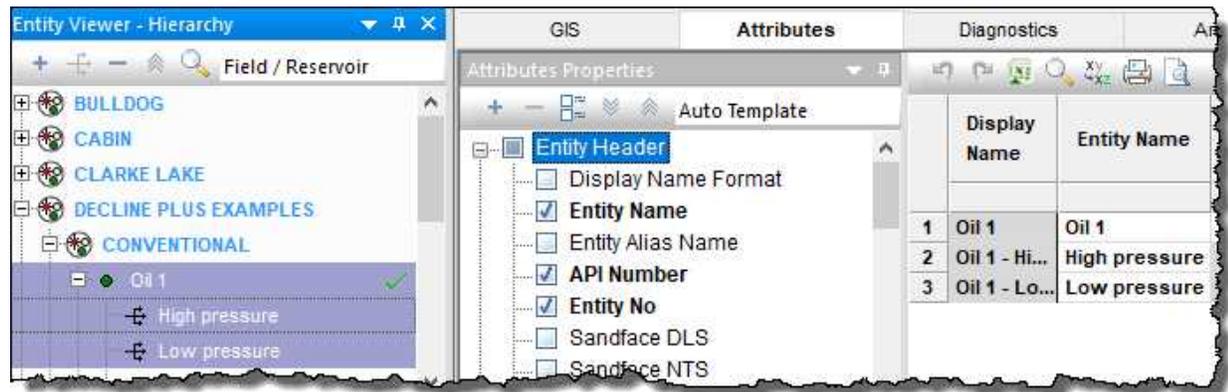
Analytics Explorer

Analytics Explorer is an analytics-driven geological, geophysical, and engineering interpretation platform.

For more information, see the Analytics Explorer help.

Attributes tab

The Attributes tab displays entity information in a table. Harmony Enterprise displays a default selection of attributes (named Auto Template) when one or more entities are selected in the Entity Viewer.



You can export this table to a .csv file. Some of the information displayed (for example, Reservoir or Operator name) is not required to perform a well analysis, but can be helpful for filtering data.

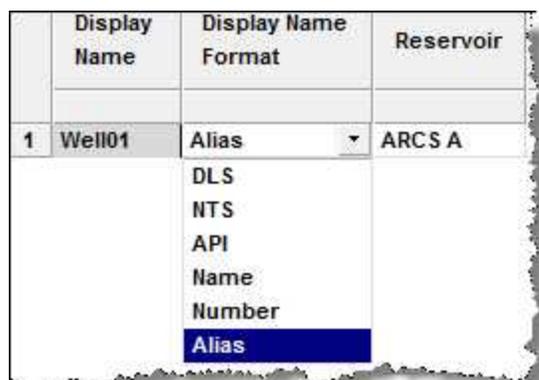
- The *Attributes Properties* tree structure to the left of the table lists all of the available well attributes. When you select an item in the *Attributes Properties* list, it is displayed in the table as a column heading. (Deselecting an attribute removes it from the table.)
- Columns added to the table are appended to the far right in the order in which they are selected. However, you can click-and-drag columns to change this order, or add a new column. You can also click-and-drag a column off of the table if you do not want that column displayed.
- Clicking a column header sorts the table data by its attribute value, according to the same sorting rules as MS Excel.

If you click a column header, and then press the **Ctrl** key, you can sort multiple columns at the same time. This is indicated by a sorting arrow in each of the columns. The columns are sorted in the order you click the header.

On Stream	Last Known Record	Cumulative G...
DD/MM/YYYY	DD/MM/YYYY	MMscf
01/09/2001	01/02/2002	11
08/09/2002	10/10/2004	101
01/01/2001	01/01/2003	380
08/06/2004	07/06/2024	1196
01/06/1992	01/03/2006	10012
01/01/1985	01/10/2010	17374
01/01/1985	01/10/2010	18292

- The first predefined attribute column is the Display Name. You can define the format of this column in the *Display Name Format* column. After the display name is set, that name format is used in every module and worksheet in Harmony Enterprise.

	Display Name	Display Name Format	Reservoir
1	Well01	Alias	ARCS A



Tip: Many users like to display an Alias for their entities. You can customize this display by selecting **Entity Alias Name** in the Attributes Properties pane and typing your alias name in the Entity Alias Name column.

Well attribute data can be imported from a file / database, entered manually, or copied-and-pasted from another table cell. The table cell's color can be used to identify the method by which data can be entered into the cell:

- **Gray** — read-only. These cells display data from another location in Harmony Enterprise, or these cells indicate that it is a calculated cell (for example, a custom attribute). Data in these cells cannot be modified.
- **White (no drop-down list)** — you can enter a value, or paste content from another cell.
- **White (with a drop-down list)** — you can select a value from the drop-down list, or you can paste a value from the drop-down list into these cells.

Scenarios

Scenarios are displayed in the same manner as wells, with these columns for additional information:

- **Scenario Name** — the name of the scenario. For more information, see [promote to well](#).
- **Created By** — the name of the user that created the scenario.
- **Last Modified Date** — the last date when the scenario was modified.

- **Last Modified By** — the name of the user that last modified the scenario.
- **Notes** — optional notes for the scenario.

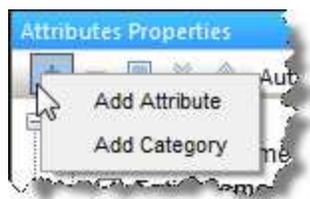
Toolbars

The Attributes tab has two toolbars: primary and secondary. The unique items are described below; for a description of common icons, see [toolbars](#).

Primary toolbar

The primary toolbar is located below the *Attributes Properties* pane.

Clicking the  icon on this toolbar lists two options.

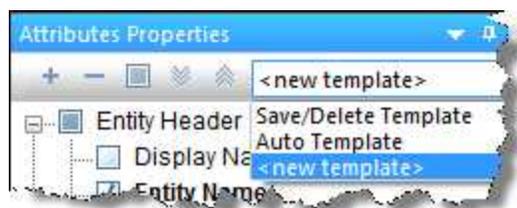


1. **Add Attribute** — opens the [Create Custom Attribute dialog box](#). You can create two different types of custom attributes: *Input* (using values you enter), and *Calculated* (using equations you enter).
2. **Add Category** — opens the Create Custom Category dialog box where you can create custom categories to group your attributes. The selection tree updates after you add your category.

Other notes on this toolbar include the following:

- You can click the **Delete custom attribute / category** icon () after selecting the custom attribute or category you want to delete. You are prompted to confirm your decision when deleting a custom attribute, but a custom category is immediately deleted. Multiple custom attributes and datasets can be deleted quickly by using the **Ctrl** and **Shift** keys.
- After you have customized the table / grid display to your liking (for example, showing or hiding attribute properties and re-ordering the category headers), you can save your configuration as a template for re-use. Click the drop-down arrow on the toolbar and select **Save / Delete Template**. To load a previously saved template, select it from the drop-down list.

- To return to Harmony Enterprise's default template, select **AutoTemplate**.



Note: Templates are user- and computer-specific; they are not database-specific.

Secondary toolbar

The secondary toolbar is located above the attributes table / grid and has the following important items:

-  **Undo / Redo** — undo your previous action, or redo your action.
-  **Find / Replace** — type the text you want to search for, and then type the text you want to use instead.

Context menus

Right-clicking the top left of your table lists these options:



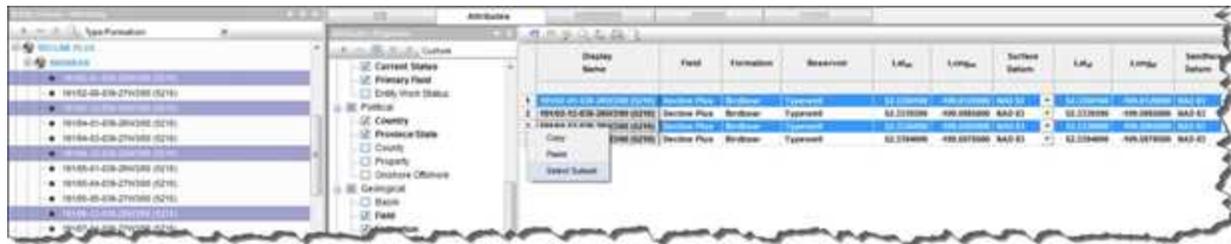
- **Copy Grid** — copies the table to the clipboard.
- **Copy Grid + Headers** — copies the table and table headers to the clipboard.

Right-clicking the numeric columns' headers (the columns displaying units in green text) lists these options:



- **Precision** — select between decimal, scientific, or engineering.
- **Units** — select the units you want to display from the submenu.

After selecting your rows using the row headers, right-clicking the row numbers to the left and selecting **Select Subset** removes the other rows in the table, and this selection persists across Harmony (for example, the Entity Viewer, GIS map, and so on).



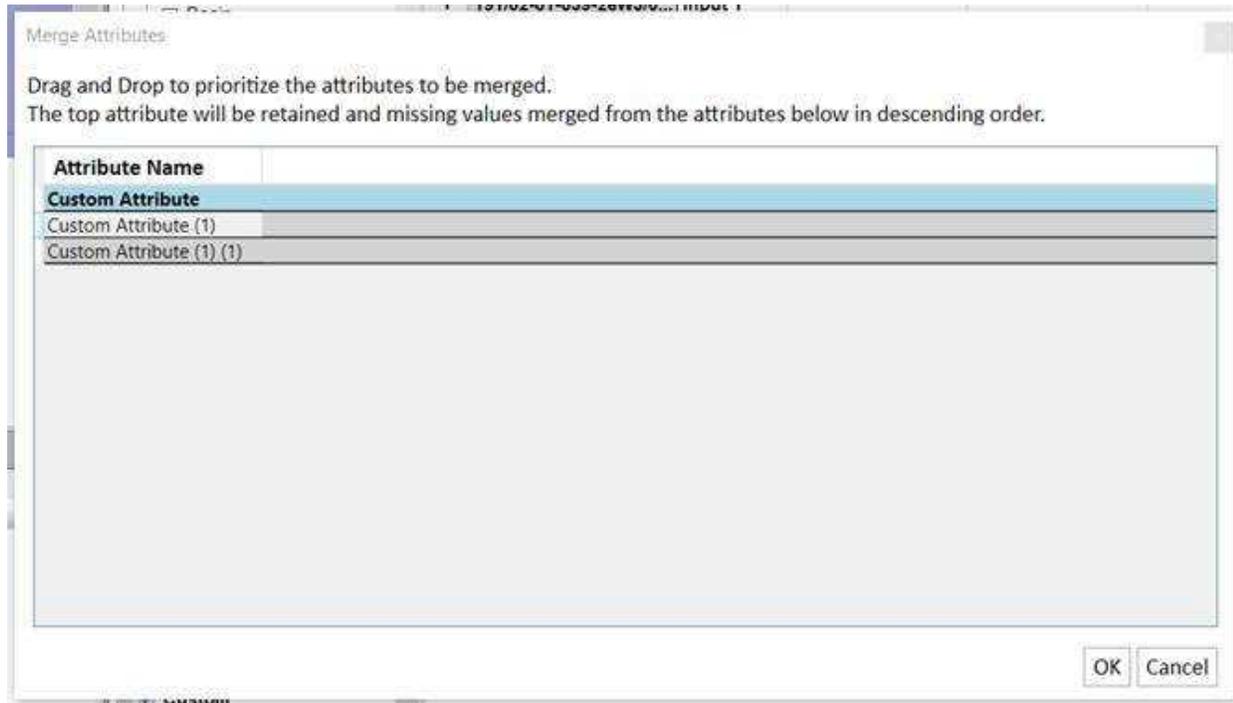
Right-clicking a *white table cell* lists these options: cut, copy, paste, and clear.

Custom

When you merge multiple .harmony files into a single SQL database or .hldb file, you often have duplicate custom attributes. You can delete extra calculated attributes, or merge custom-input attributes by right-clicking them.

	Display Name	Custom Attribute	Custom Attribute (1)	Custom Attribute (1) (1)
1	191/02-01-039-26W3/0...	Input 1		
2	191/02-08-039-27W3/0...	Input 1		
3	191/02-12-039-26W3/0...	Input 1	Input 2	
4	191/04-01-039-26W3/0...		Input 2	
5	191/04-03-039-27W3/0...		Input 2	
6	191/04-12-039-26W3/0...		Input 2	Input 3
7	191/05-01-039-26W3/0...			Input 3
8	191/05-04-039-27W3/0...			Input 3
9	191/05-05-039-27W3/0...			Input 3

In the Merge Attributes dialog box, drag the most correct or complete attribute to the top. All the other attributes are merged into this custom attribute.



	Display Name	Custom Attribute
1	191/02-01-039-26W3/0...	Input 1
2	191/02-08-039-27W3/0...	Input 1
3	191/02-12-039-26W3/0...	Input 1
4	191/04-01-039-26W3/0...	Input 2
5	191/04-03-039-27W3/0...	Input 2
6	191/04-12-039-26W3/0...	Input 2
7	191/05-01-039-26W3/0...	Input 3
8	191/05-04-039-27W3/0...	Input 3
9	191/05-05-039-27W3/0...	Input 3

In order to merge custom-input attributes, keep these rules in mind:

- All attributes must be custom input (that is, no calculated or pre-existing / default attributes).
- All attributes must be the same type (that is, text, date, or number).

- If a well has values in multiple attributes, the order of the attributes in the Merge Attributes dialog box determines which value is maintained.

Note: You cannot merge if well security (see [role-based security](#)) is enabled because the merge is applied globally to all wells in the database or file.

Custom attributes

You can create custom attributes in Harmony Enterprise.

- When you click the **Add Custom Attribute / Category** icon () icon on the *Attributes Properties toolbar* and select **Add Attribute**, the [Create Custom Attribute dialog box](#) opens.
- Your custom attribute is displayed in the *Attributes Properties pane*, under the category you have selected.
- You can remove a custom attribute by selecting it and clicking the **Remove Custom Attribute / Category** icon () icon in the *Attributes Properties toolbar*. Multiple custom attributes and datasets can also be deleted quickly by selecting them and pressing the **Ctrl** and **Shift** keys.
- You can rename or edit your custom attribute's formula, by right-clicking it and selecting **Rename** or [Edit Formula](#).

Custom-calculated numeric attributes

If you selected **Number** for your *Unit Type* in the Create Custom Attribute dialog box, you created a custom-calculated numeric attribute.

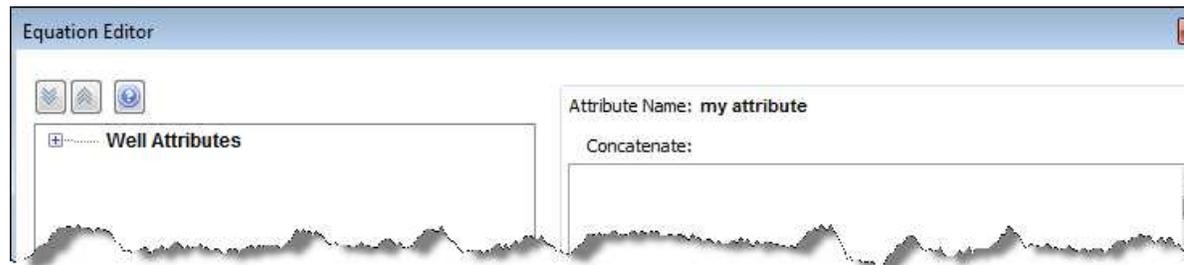
Clicking the **Edit Formula** button in this dialog box opens the Equation Editor, where you can use a combination of existing production datasets, custom-input datasets, custom-calculated datasets, well attributes, custom-input attributes, custom-calculated attributes, constants, and mathematical operators to build your equation. For more information, see the [Equation Editor dialog box](#).

Custom-calculated text attributes

You can add a custom-calculated text attribute using a combination of existing text attributes, custom-text attributes, custom-calculated text attributes, and user-defined text.

When you click the  (Add Custom Attribute / Category) icon and select **Add Attribute**, the Create Custom Attribute dialog box opens.

- When you select **Text** from the *Attribute Style* drop-down list and **Calculated** for the *Type of Attribute*, the Equation Editor opens.



- You can type in the Concatenate pane, or you can select the attributes you want from the tree structure; then click **OK**.

The top part of the Equation Editor has the following components:

- **Tree structure** — displays an updated list of all the text attributes that are available for concatenation. This includes existing text attributes, custom-input text attributes, and custom-calculated text attributes. Clicking an item in the tree structure inserts it into the formula.
- **Concatenate pane** — displays the text attributes and user-defined text for concatenation (links items together).

Attributes editor support for multilayer wells and layers

Multilayer wells contain the same attributes as a standard single-layer well.

Layers contain the same attributes as a well. Of those attributes, some are inherited from the well, while others are unique to the layer.

Attributes are displayed if wells are (or a well is), selected. Attributes are displayed if layers are (or a layer is), selected. However, attributes are not displayed, if the selection contains a mixture of layers and wells.

Note: The Number of Fractures attribute, *nf*, is displayed at the well level, and is calculated by summing the Number of Fractures from all of the well's layers.

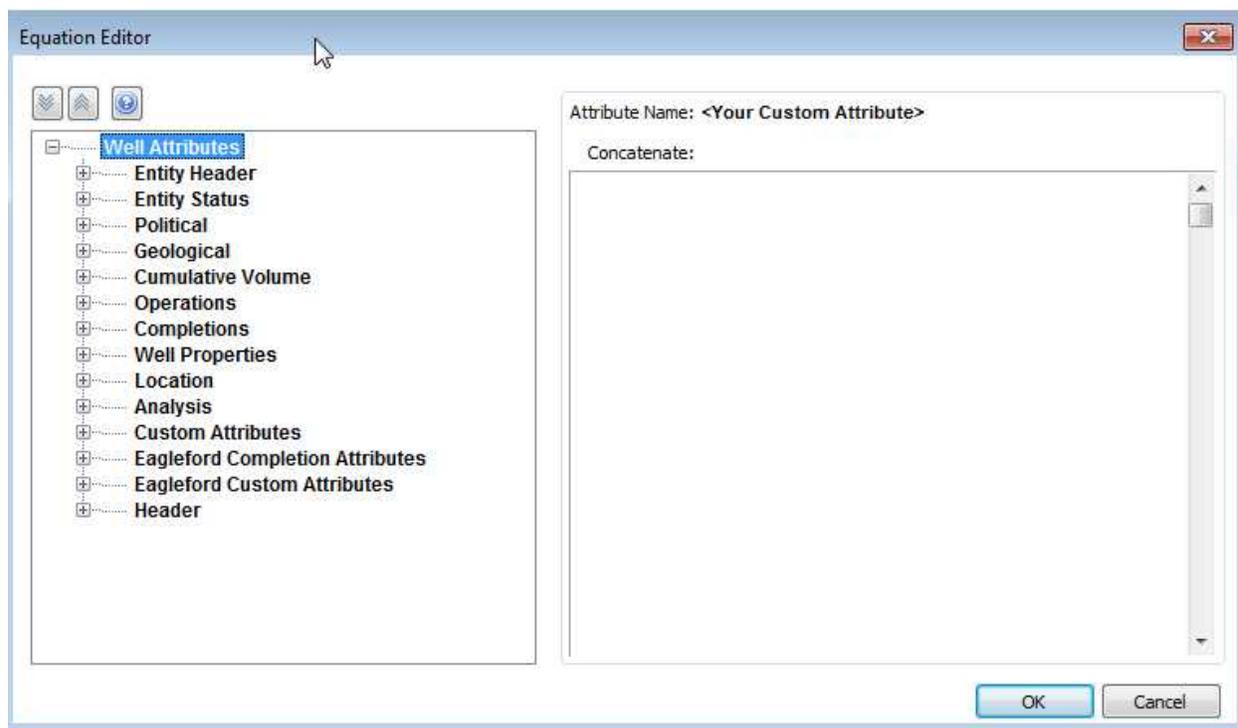
Create Custom Attribute dialog box

This dialog box is commonly used when you add custom attributes. In this dialog box you are required to select your attribute type (*Input* or *Calculated*), style (*Number* or *Text*), and unit type (when applicable). You are also required to define a name and location for your attribute.

- **Attribute Name** — type a name for your custom attribute. This cannot be edited after the attribute is created, and this is a required field.
- **Attribute Style** — select Text, Number, or Date from the drop-down list. Note that this field cannot be edited after it is set.
- **Unit Type** — select your unit type from the drop-down list (enabled when you select Number for your Attribute Style). Note that this field cannot be edited after it is set.
- **Default Field Unit** — select your default field unit from the drop-down list (enabled when certain unit types are selected). By choosing a default unit, you specify in what unit, by default, your attribute is displayed. This can later be changed by toggling the displayed unit at the top of your attribute column.
- **Default Metric Unit** — select your default metric unit from the drop-down list (enabled when certain unit types are selected). By choosing a default unit, you specify in what unit, by default, your attribute is displayed. This can later be changed by toggling the displayed unit at the top of your attribute column.
- **Location** — select the attribute's location in the Attribute tab's tree structure from the drop-down list. This is a required field and you cannot click OK until a location has been selected.
- **Input** — uses values you enter.
- **Calculated** — opens the Equation Editor dialog box where you enter formulas for this attribute.

Equation Editor dialog box

This dialog box is commonly used when you add custom datasets or add custom attributes, and you want to use a Calculated type of dataset or attribute.



The Equation Editor has the following components:

- **Tree structure** — displays an updated list of all the production datasets that exist in the Production editor, as well as the numerical attributes that exist in the Attributes tab. This includes custom-calculated datasets, custom-input datasets, custom-input attributes, and custom-calculated attributes. Clicking an item in the tree structure inserts it into the formula.
- **Inputs / Units pane** — displays the units associated with each input.
 - If a dataset or attribute is displayed in an equation twice, only one unit can be associated with that variable.
 - The table / grid displays a list of datasets / attributes in the formula pane when you click the **Update Grid** button, *after* you enter a valid formula. You can also update the table / grid each time you make a modification to the formula by clicking the **Update Grid** button.
 - Note that if your formula is invalid, clicking **OK** or **Update Grid** displays an error message in the lower left corner of the dialog box.
- **Calculator** — consists of numbers and mathematical functions.
- **Formula pane** — displays the formula as you create it.

- The *output unit* is the unit associated with the output of your formula.
- By clicking the four icons directly above the formula area, you can insert subscript, superscript, and symbols within the formula.
- You can use both the on-screen calculator (by clicking the buttons in the dialog box) and your keyboard.

Tip: When entering a formula, make sure to add the closing “)” when using a function that opens with a “(“. If your formula is invalid, clicking **OK** displays an error message in the lower left corner of the dialog box.

Referencing other datasets / attributes

You can enter a formula into the Formula pane using the keyboard. To reference another dataset or attribute, you must use the following format:

- Attribute: [A:Attribute Name]
- Dataset: [P:Dataset Name]

Best-fitting functionality

There are several methods you can use to manipulate your decline curve.

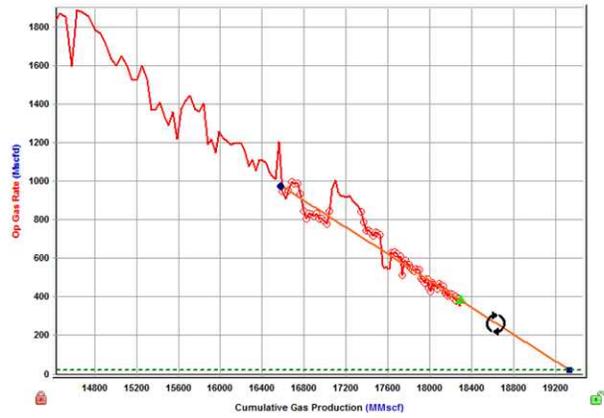
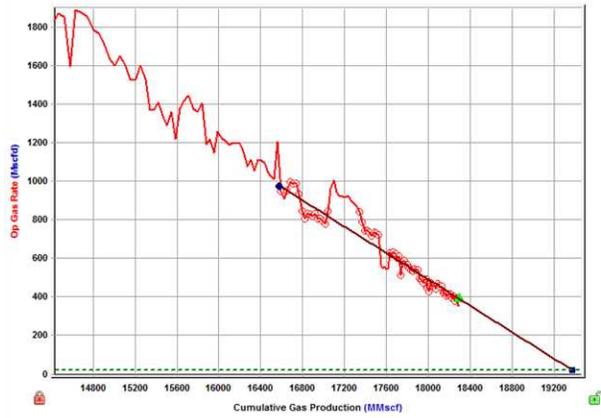
When manipulating the decline curve, there are three data points to be aware of.



1. **Left point** — any historical data point. (The section between the left point and the forecast start date is not included in the forecast; it is only used to show the match to historical production.)
2. **Forecast Start Date** — the middle point on the line; this is the forecast start date (FSD).
3. **End point** — the expected ultimate recovery.

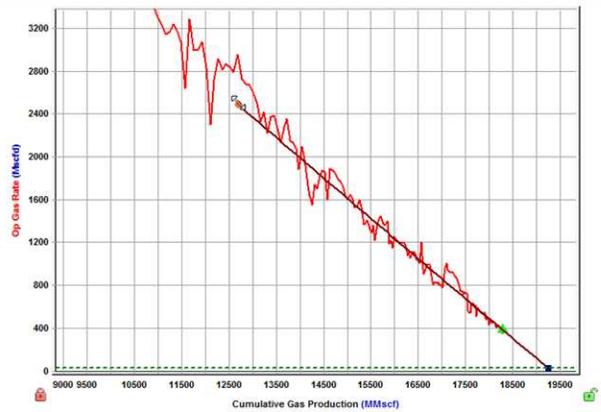
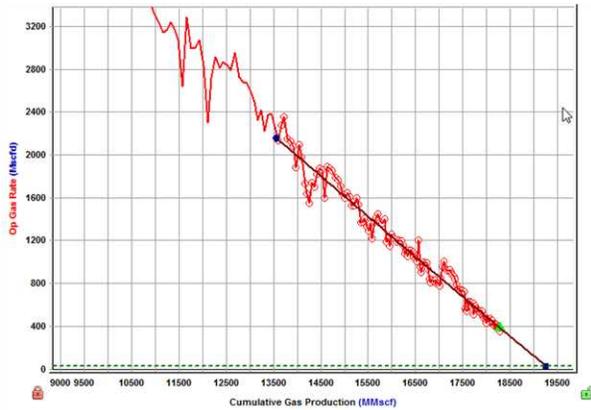
Changing the slope of the decline curve

To change the slope of the decline curve, click the decline curve line and drag. The line pivots around the FSD point, changing the decline rate and forecast duration. (If you drag the segment that does not have the FSD within it, the line pivots around the segment's start point.)



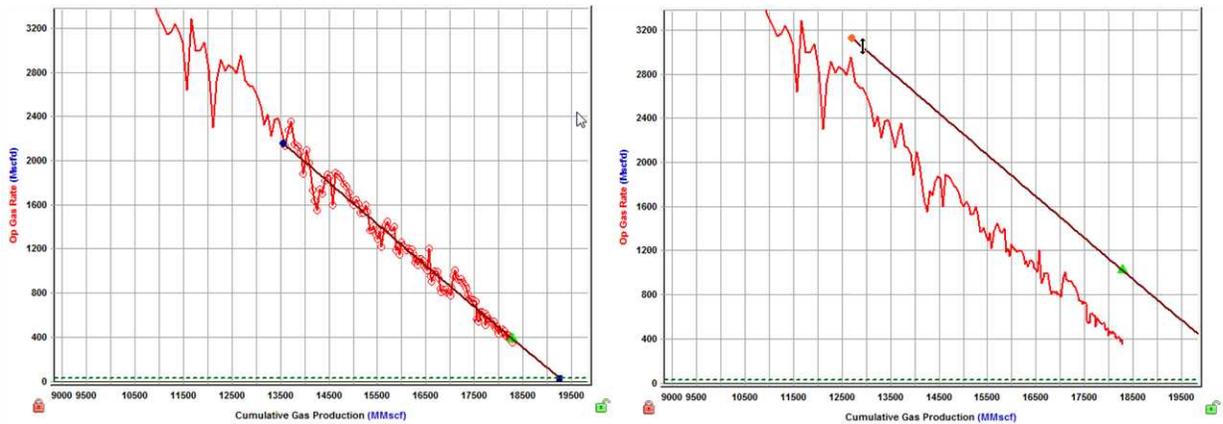
Changing the historical match

To change the historical match, click the left point while pressing the **Shift** key, and then drag it to a new position. This changes the portion of the historical production data used, but it does not change the analysis.



Changing the initial rate

To change the initial rate, click-and-drag the left point up or down. The initial rate and forecast duration change. Alternatively, you can click-and-drag the FSD point up or down.



Changing the FSD

To change the FSD, enter a new date in the Forecast Start Date field in the Analysis Parameters pane.

Analysis Parameters

Rate Type	Op. Day	
Forecast Start Date	01/10/2010	DD/MM/YYYY
q	381.8	Mscfd
d sec	12.589	%/year
b	0.016	

Segment 1

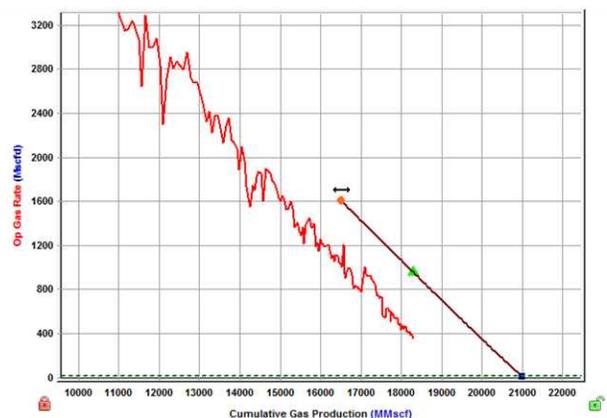
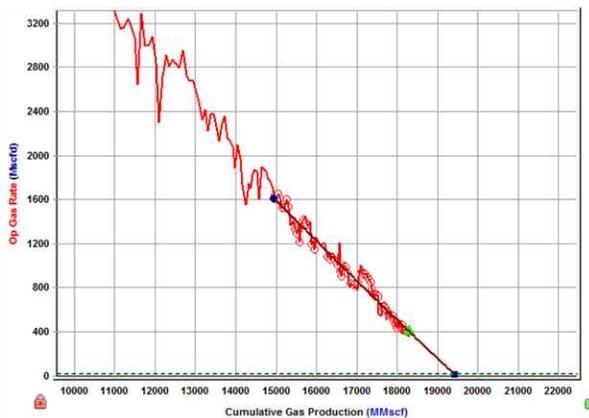
Calc Method	Δt Q_r	
Start Date	11/06/1999	DD/MM/YYYY
q_i	1781.2	Mscfd
Q_i	14554.890	MMscf
Δt	424.193	month
d_i sec	12.890	%/year
b	0.016	<input checked="" type="checkbox"/>
q_r	16.2	Mscfd
End Date	16/10/2034	DD/MM/YYYY
ΔQ	4740.412	MMscf
Q_r	19295.302	MMscf

If you click-and-drag the FSD point left or right while holding down the **Ctrl** key, the FSD point moves together with the decline curve.

If you click-and-drag the FSD point left or right while holding down the **Shift** key, the FSD point moves along the decline curve (the curve itself does not move).

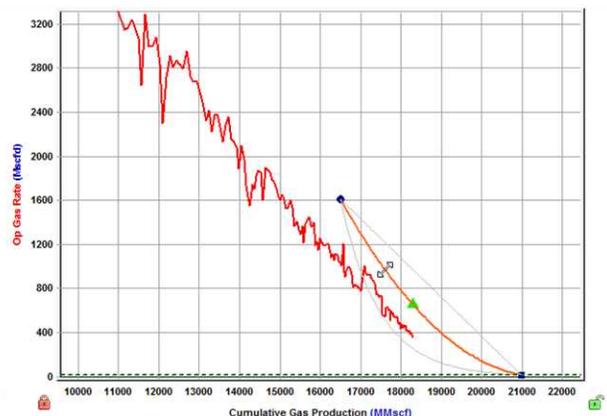
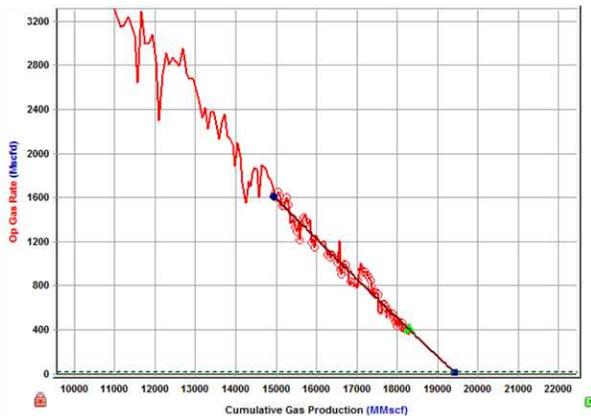
Changing initial cumulative production & final cumulative production

To change the initial cumulative production and final cumulative production, click-and-drag the left point while holding down the **Ctrl** key. This changes the start point without changing the initial oil / gas rate or decline rate.



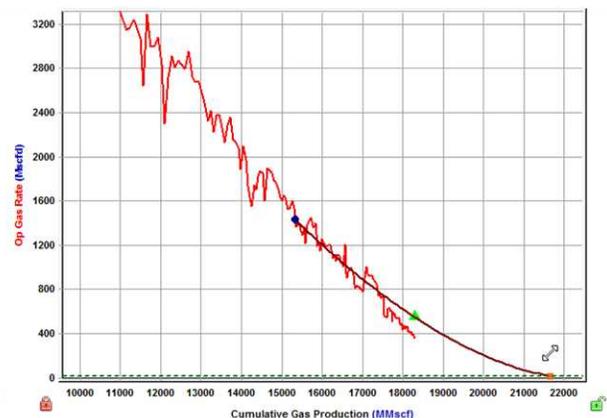
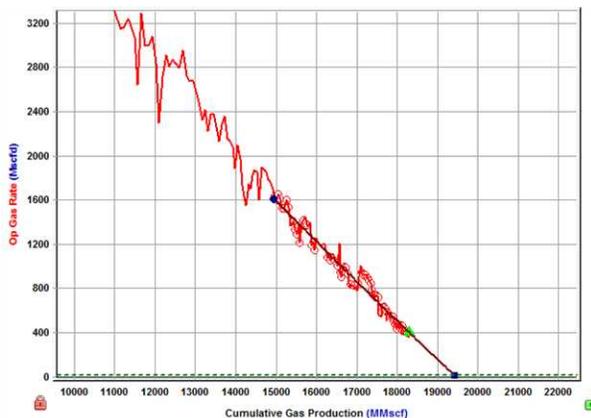
Changing the b value

To change the b value, click-and-drag the decline curve while holding down the **Ctrl** key. This changes the decline exponent value and the start point, while the left point and end point remain fixed. (The gray guidelines represent decline exponents of 0 and 1.)



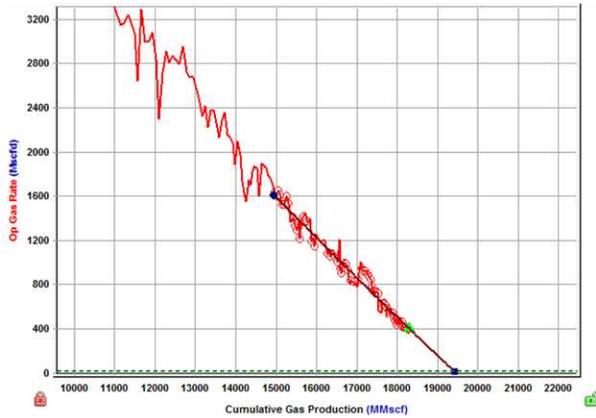
Changing the *b* value & final cumulative production

To change the *b* value and final cumulative production while maintaining the initial gas / oil rate, drag the end point while holding down the **Ctrl** key. (This method does not show the gray guidelines.)



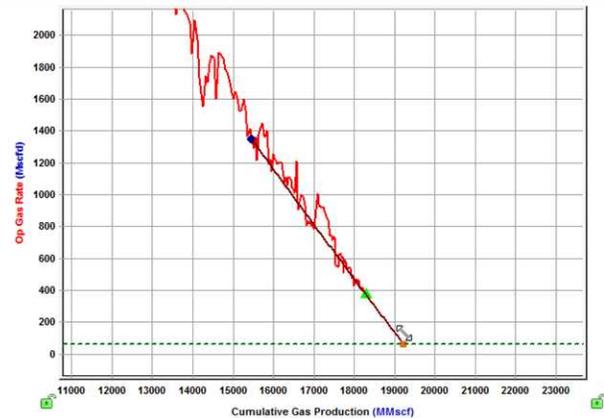
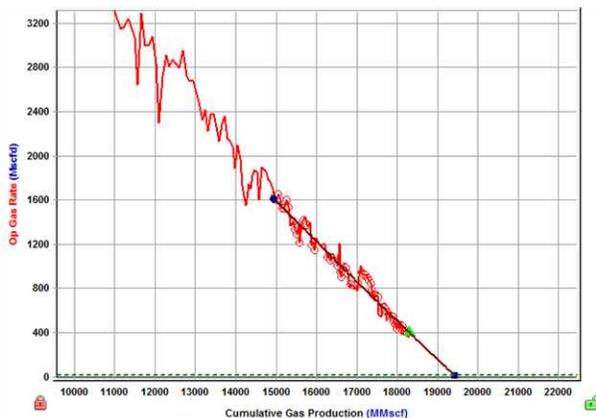
Changing final cumulative production & decline rate

To change the final cumulative production and the decline rate, drag the end point left or right. This changes the cumulative production of the segment and the forecast duration, without changing the final rate. The initial gas / oil rate and decline rate are also changed.



Changing the abandonment rate

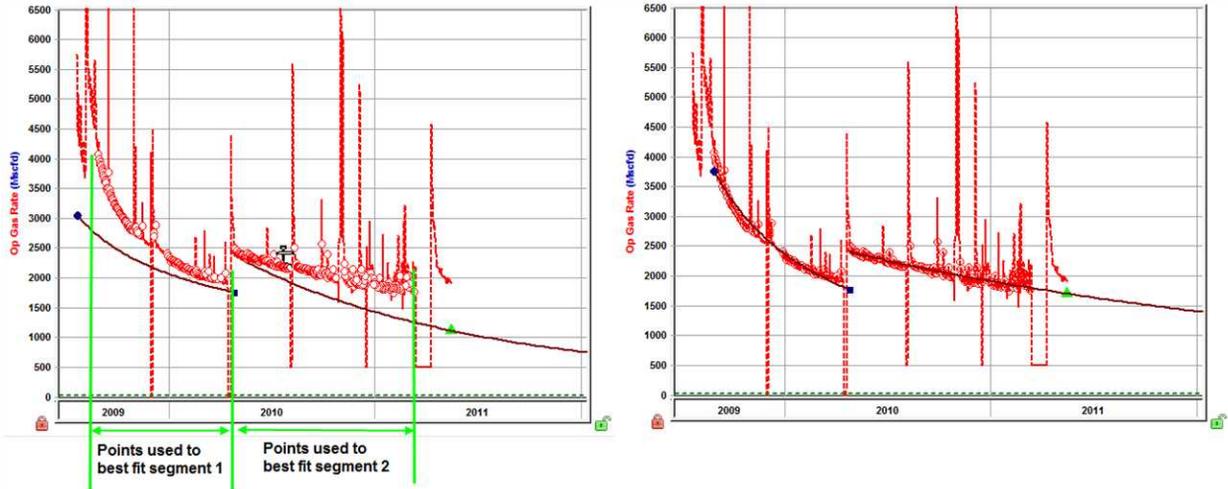
To change the abandonment rate, drag the end point while holding down the **Shift** key. The final rate, cumulative production, and forecast duration are changed without changing the decline exponent, or effective decline rate.



Manipulating multiple segments

Individual segments can be best fit to the corresponding data interval by using the data selection tool, and selecting data points between the start and end date of that segment.

Alternatively, selecting data points that span multiple segments best fits each segment to the points that lie between their individual start and end dates.



When best fitting using the data selection tool, the start date of the first segment corresponds to the first data point that is selected. The end date of the first segment can be changed by clicking-and-dragging the point left or right.

The end date of the first segment corresponds to the start date of the second segment. These dates are always be the same; however, the initial rate of the second segment does not necessarily have to be the same as the final rate of the first segment. (Additional segments can be added as needed.)

Manipulating a multi-segment decline

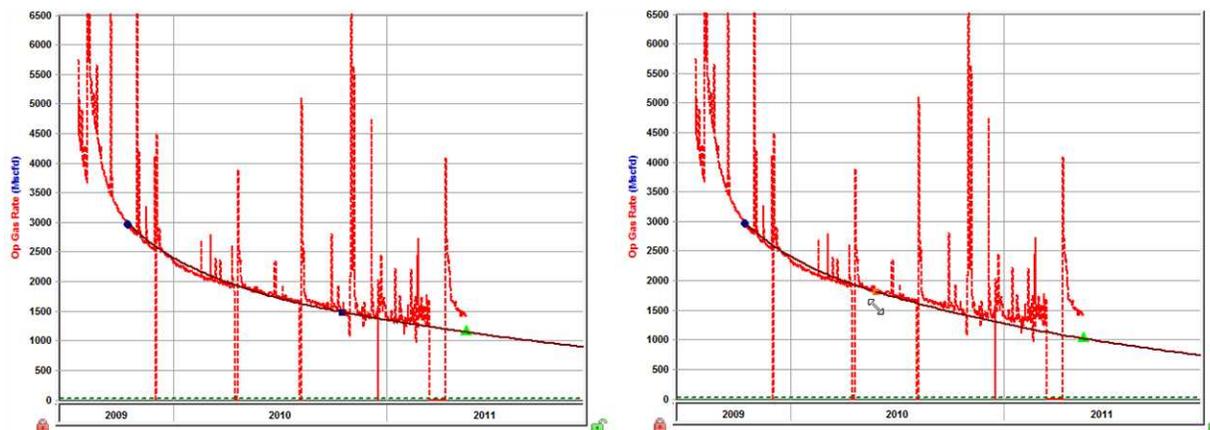
A multi-segment decline is initially "best fit" using all data points as follows:

- with the start date of the first segment equal to the start of production
- the end point of the first segment defined by the constraints entered in the Options dialog box
- the start date of the second segment equal to the end date of the first segment
- the end date of the second segment defined by the final gas rate

The first and second segments are always continuous, with the end date of the first segment equal to the start date of the second segment. As well, the instantaneous decline rate at the end of the first segment is equal to that at the beginning of the second segment.

Due to the continuity between the first and second segments, manipulating the shape of the first segment's decline curve impacts the second segment's decline curve.

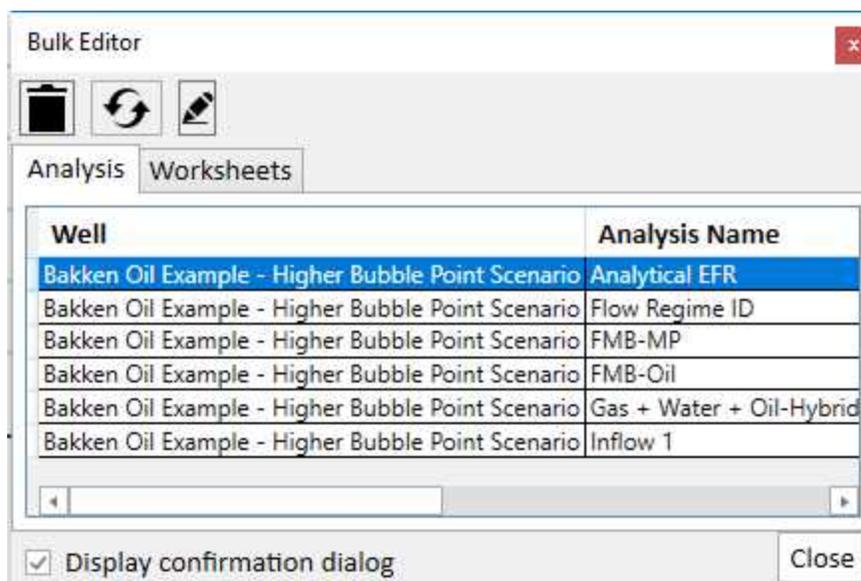
All line manipulations described above can be applied to the multi-segment decline analysis. The length of the first decline segment can be changed by clicking the end point of the first segment and dragging left or right.



Bulk Editor dialog box

This dialog box is accessible by clicking the **Bulk Editor** icon () in the main toolbar.

In this dialog box, you can delete or rename multiple analyses and worksheets quickly.



Select the analyses you want to delete or rename in the Analysis tab, and select the worksheets you want to delete or rename in the Worksheets tab. If you want to sort columns, click the column headers.

By default, the **Display confirmation dialog** option is selected. This means that if you make a change, a popup opens where you have to click **Yes** to confirm your decision.

Icons

Both tabs have the same icons.



Delete — deletes the analyses or worksheets you have selected. If an analysis or worksheet is locked by another user, a message is displayed at the bottom of this dialog box and in the Status Window. You are prompted to confirm your deletion.



Refresh — refreshes the list in the table, which can be useful when another user releases / unlocks an analysis or worksheet.



Rename — opens the Rename dialog box where you type a new name for your currently selected analyses or worksheets.

Exceptions

These exceptions apply to the bulk editor:

Selected groups of entities only display the analyses / worksheets at the group level, and not for individual entities. For example, if Well 1 and Well 2 are in a group called Pool A, and you select Pool A before opening the bulk editor, then analyses for Pool A are displayed, but analyses for Well 1 or Well 2 are not displayed individually.

Classified reserve analyses are not listed and cannot be deleted or renamed using the bulk editor.

The bulk editor treats linked analyses differently from other analyses. (You can tell that an analysis is linked if the Analysis Manager has more than one sub-analysis listed.) If you delete or rename a linked analysis, both the parent and child items are deleted or renamed.

If you delete or rename an FMB, typecurve, analytical, or numerical analysis, then the associated worksheet is also deleted or renamed. If you delete or rename the worksheet, the analysis is also deleted or renamed. The reason for this is because unlike other worksheet types that can display multiple analyses of various types, each of these worksheets is linked to its own analysis.

If you delete or rename a consolidated forecast, only the consolidation is deleted or renamed. The child analyses used in the consolidation are not deleted or renamed.

Database connection

These dialog boxes apply to the database connection:

- [Set Up Connection Settings dialog box](#)
- [Assign Mapping dialog box](#)
- [Well Linking Criteria dialog box](#)
- [Set Up Filters dialog box](#)
 - [Filter a Column dialog box](#)
- [Select Wells to Import dialog box](#)
- [Select Analyses to Import dialog box](#)
- [Import Options dialog box](#)

Set Up Connection Settings dialog box

This dialog box is commonly used when you [import well data from a database](#), and enables you to create or edit your database connections.

Connection Name — (required) type the name of your database connection.

Connect to — select your data source: either an Access database or other data source.

- **Access File** — browse to the location of your Access database.
- **Data Sources** — select the open database connection (ODBC) that connects Harmony Enterprise to your source database. Or, click the **Add New button**, which opens the ODBC Data Source Administrator dialog box.
 - **Data Source Options** — can be set after **Data Sources** is selected.
 - **Set Username and Password** — if login credentials are required for accessing your database, you can save the user name and password. Note that this field can be left blank.
 - **Set Schema** — set the database schema that the data is stored in. Note that this field can be left blank.
 - **Use quoted identifiers** — encloses database object names within quotes for queries. For more information, contact [technical support](#) (opens in a new window).
- **FieldDIRECT File** — browse to the location of your .mdf file.

Assign Mapping dialog box

This dialog box is commonly used when you import well data from a database. You can import well production, attributes, fluid properties, wellbore configurations, and declines (Aries only). Mappings for each connection are saved and shared with all users for the current Harmony Enterprise database.

Note: The Source columns shown below are for the table in your source database. The Next button is disabled until all of the mapping errors are corrected. The view definitions that outline the data fields that can be imported, and the expected format, are summarized in the View Definition spreadsheet.

This dialog box has the following icons:

-  **Learn more about Database Mappings** — opens this topic for the Assign Mapping dialog box.
-  **Open the View Definition Excel file** — opens an .xlsx file that summarizes the view definitions for the data fields that can be imported and the expected format.

Views:

To download the View Definitions, see the Excel file. A summary of the headers is given below. To import data from your internal database into Harmony Enterprise, views / tables in your database (**Client Tables / Views**) must be mapped to the corresponding Harmony Enterprise view.

- ARIES_DECLINE_ANALYSES — supports Arps' decline analyses formatted from Aries.
- PRODUCTION_HISTORY — historical production rates and volumes including custom datasets. Custom datasets must be created in Harmony Enterprise before they can be imported.
- WELL_INFORMATION — well attributes and reservoir properties including custom attributes.

Important: Custom attributes must be created in Harmony Enterprise before they can be imported. For more information, see custom attributes.

- RESERVOIR_PROPERTIES — general initial reservoir properties, such as initial reservoir pressure, temperature, and saturations.

- GAS_PROPERTIES_HISTORY — gas gravity and produced gas composition. Can accommodate multiple PVT test results over time, or a single result.
- LIQUID_RICH_GAS_PROPERTIES — condensate gravity along with CGR and recombined gas rate.
- OIL_PROPERTIES — oil gravity, bubble point pressure, and initial GOR.
- OIL_CALIBRATION_PROPERTIES — calibration pressure, temperature, formation volume factor, compressibility, and viscosity.
- SEPARATOR_PROPERTIES — temperature and pressure in the separator.
- CUSTOM_GAS_PVT_PROPERTIES — custom gas formation volume factor table.
- CUSTOM_GAS_VAPORIZED_OIL_PROPERTIES — custom vaporized oil ratio table.
- CUSTOM_GAS_VISCOSITY_PROPERTIES — custom gas viscosity table.
- CUSTOM_VISCOSITY_OIL_PROPERTIES — custom oil viscosity table.
- CUSTOM_SATURATED_OIL_PROPERTIES —oil formation volume factor and solution gas oil ratio custom tables below bubble point.
- CUSTOM_UNSATURATED_OIL_PROPERTIES — oil formation volume factor and solution gas oil ratio custom tables above bubble point.
- WATER_PROPERTIES — water gravity, salinity, viscosity, compressibility, formation volume factor, and solution gas water ratio.
- SHALE_PROPERTIES — shale Langmuir volume, shale Langmuir pressure, and bulk density.
- WELLBORE_CONFIG — configuration name, date and ID, as well as datum, flow path, and pressure loss calculation correlation.
- WELLBORE_CONFIG_DETAILS — top and bottom casing depths, tubing and perforations, along with casing and tubing diameters. Deviation surveys and detailed temperature profiles are also defined here.
- PVT_PROPERTY_CORRELATION — sets all correlations used in the Properties editor along with the Gas Type.
- GEOMECHANICAL_PROPERTIES — imports the formation properties Permeability Modulus and Biot Effective Stress Coefficient.
- STATIC_PRESSURES — imports static-pressure data.

Columns:

After mapping your views / tables to the Harmony Enterprise incoming views, the columns within these views must be mapped. For numeric columns that have been mapped, specify the units that these values use in your database.

Note: For well information, you can assign a field to more than one column, and you do not have to map production data.

Errors and minimum requirements

Every table that is mapped must have at least the well key and one other column specified. (The well key is the identifier used in the source database to separate wells.)

When there are errors in the database mapping, a red X is displayed next to the Harmony Enterprise Views (destination) and the Harmony Enterprise Column Name. At the top of the Assign Mapping dialog box, an error count is listed. Errors may include missing identifiers, or mapping a column of an inconsistent data type (for example, mapping text to numeric Harmony Enterprise data).

Well Linking Criteria dialog box

This dialog box is commonly used when you import well data from a database. Incoming well data is linked to existing wells using attributes.

Selected attributes are used to link / merge incoming wells, and are ranked in order of priority.

To include attributes from the linking process, select their checkboxes. To exclude attributes, deselect their checkboxes. To change the order of priority, click the attribute you want to change, and then click the **Move Up** or **Move Down** buttons.

Settings are saved within the Harmony Enterprise project database for the current database connection. In order to share your settings, you need to click the **Export Criteria** button. You can then share the .wlc file with colleagues.

You can import an .wlc file by clicking the **Import Criteria** button (similar to sharing a template) .

To go back to the settings in the Options dialog box, click the **Reset to Global Options** button.

Note: For a given database connection, Harmony Enterprise saves the linking criteria, and this is available to all users who use that connection for their project data-

base. To apply the linking criteria to database connections created later, you can import the .wlc file.

Set Up Filters dialog box

This dialog box is opens when you import well data from a database. You can use text attributes to filter wells in the source database, and any wells that meet all of your parameters are included in the well selection list. Note that filters operate on an *exact* match only.

- **Add** — opens the Filter a Column dialog box.
- **Edit** — after selecting a filter, you can click Edit and update your filter values.
- **Delete** — after selecting a filter, you can delete it.

If you select or deselect the **Disable all Filters** option, this setting is saved for your current database connection. Enabling this option means that no filtering is done; all of your wells are imported. (It is the same thing as not setting up any filters.)

Note: All of the filter settings are stored for each user for each database connection. These settings are *not* saved between users.

Filter a Column dialog box

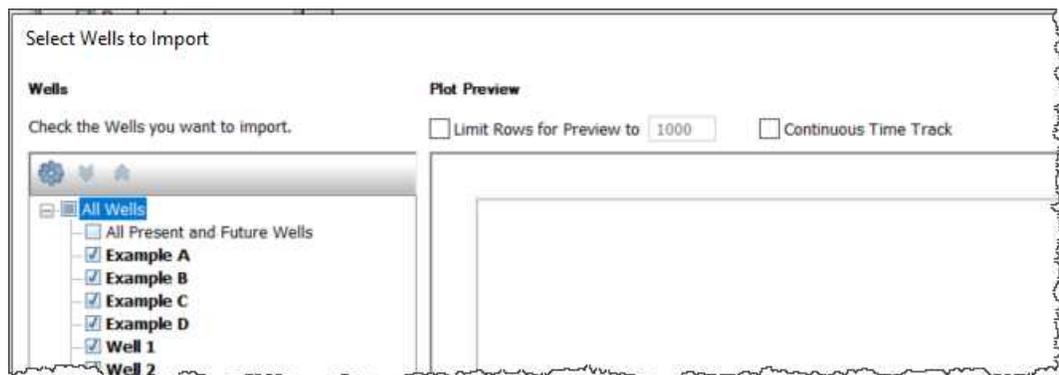
This dialog box is commonly used when you import well data from a database. Filtering columns reduces the time it takes to display wells.

Filter Column — select an attribute from the drop-down list to specify a filter column. Click the blank box and type values for the attribute, pressing **Enter** after each value. When done, click the **OK** button.
The columns displayed in the drop-down list are based on your mapped columns in the WELL_INFORMATION view.

Some of the attribute values use checkboxes instead of a user-defined list. In these cases, click the checkboxes for the values you want.

Select Wells to Import dialog box

This dialog box is commonly used when you import well data from a database.



Wells pane

If the left pane is blank, you need to click the Tree Hierarchy icon () and configure your well hierarchy.

Toolbar

This dialog box has these items on its toolbar:

-  **Tree hierarchy** — opens the Configure Well Hierarchy dialog box where you can organize entities in a hierarchical structure according to specific attributes. Click this icon to create a hierarchy view of your wells, which is categorized to your preferences.
-  **Expand all** — expands all nodes of the tree structure displayed in the pane.
-  **Collapse all** — collapses all nodes of the tree structure displayed in the pane.

Well hierarchy

Select the wells you want to import from the tree structure.

- **All Wells** — imports all of the wells in the hierarchy.
- **All Present and Future Wells** — adds existing wells and future wells. If you add wells to your source, they are automatically imported the next time you import, even if these wells do not exist in your source today. By *not* selecting this option, you will need to manually add new wells the next time you import.
- <Select individual wells> — imports the wells you select individually.

Plot preview pane

To see a preview of your well production, click the well's name (not its checkbox).

To limit the number of rows displayed in the Plot Preview pane, click the Limit Rows checkbox and type a limit. The default setting is 1000 rows. Note that your preview limit is saved for all of your database connections, and changing the limit value affects the next well that is selected.

The *Continuous Time Track* option is used to adjust your data depending on your shut-in conditions. It is extremely important that you use this feature correctly, as your volume and rate data is influenced by this setting. For more information, see [Continuous Time Track](#).

Select Analyses to Import dialog box

This dialog box opens (in the [database connection](#)) if you mapped decline analyses.

Select the decline curves you want to import.

Decline Analysis Options

Select the rate you used to perform your decline analysis in Aries: **Operated** or **Calendar**.

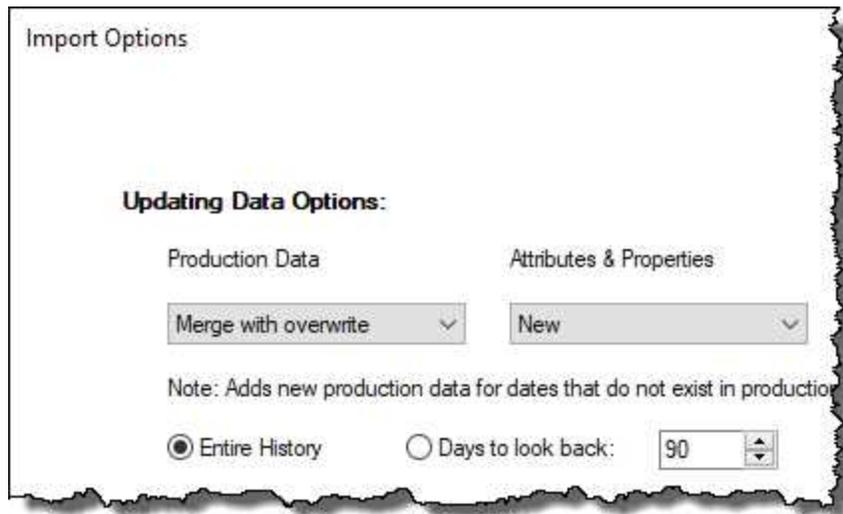
Import Options dialog box

This dialog box is used when you [import well data from a database](#).

Updating Data Options

The settings in this dialog box are based on the global settings in the [Options dialog box](#). However, you can change these settings to override the global settings for the current database connection. For information on command line abbreviations and an example, see [command line](#).

Production Data — see [updating data | production data](#).



Other options are as follows:

- **Entire History** — by default, the entire production history is imported.
- **Days to look back** — if you have extensive production data, it can take longer to import. By setting a number of days to look back (between one day and 365 days), you can reduce the import time.

If you select a number of **Days to look back**, any data prior to the look-back time period remains unchanged. Any merging and overwriting logic, or discard and replace logic, is applied only to the look-back time period. Harmony Enterprise scans the Date Time column mapped in the source database's production history table, and uses the single most-recent date for all values in the Date Time column. For example, if the date was July 20, 2020, and our look-back time period was set to 15 days, then data is imported between July 5 and July 20, 2020. Note that only the dates in the source production database are considered; the dates in the Harmony Enterprise project are not used.

Note: If a well was not selected for import, it still exists in the production table. Harmony Enterprise scans the dates for that well, and all other wells, in the production table. The look-back time period is not applied on a well-by-well basis. Instead, a single date is returned to look back from, and the same time period applies to all wells.

Attributes & Properties — [updating data | attributes and properties.](#)

Analysis Data — [updating data | analysis data.](#)

Wellbore — [updating data | wellbore data.](#)

Static Pressures — [updating data | static pressures.](#)

Autocalc Options

Automatic calculation options are as follows:

- **Do Sandface Autocalculations on Wells** — automatically calculates sandface pressures on wells during an import, if this option is selected.
- **Do Sandface Autocalculations on Scenarios** — automatically calculates sandface pressures on scenarios during an import, if this option is selected.

Note: Calculating sandface pressures can take a considerable amount of time depending on the number of wells and their complexity.

Data Reduction Mode

Data reduction is the process of reducing high-frequency data prior to importing. Data reduction options include the following:

- **None** — data reduction is not applied.
- **Auto** — applies data reduction as per your settings in the Options dialog box.
- **Manual** — opens the Data Reduction dialog box where you can customize your settings.

Auto Import

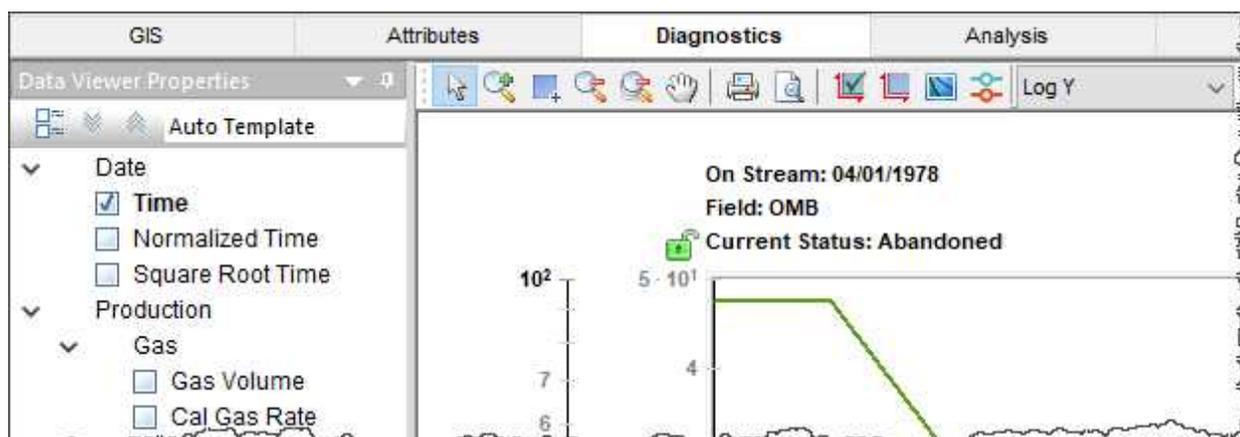
To schedule automatic well updates using the Windows Task Scheduler or command line, click the **Auto Import** box.

For more information, see Windows Task Scheduler and command line.

Diagnostics tab

The Diagnostics tab displays customizable plots consisting of production, injection, and pressure data for each well or scenario in a Harmony Enterprise project. Selecting parameters in the Data Viewer Properties pane displays these items on the plot.

- If you select more than one entity, the selected data from all these entities is displayed in the diagnostic plot.
- Hovering your mouse over selected entities in the Entity Viewer (Hierarchy or Custom) makes their plot lines become bold.



You can send your plot to a [comparison plot](#), by right-clicking it and selecting **Send Plot to Comparison Plot**. You can also right-click a dataset in the plot and select **Send Dataset to Comparison Plot**. For information on other options, see [plot options](#) and [locks](#).

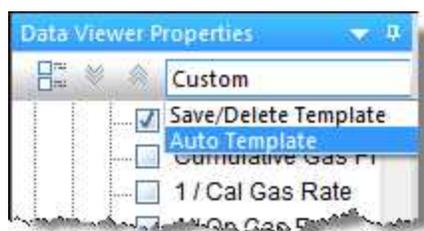
Note: If a custom dataset does not exist when a template is applied, the dataset is not added to the plot.

Toolbars

This tab has two toolbars: a primary toolbar for the Data Viewer Properties pane and a secondary toolbar above the plot. For a description of common icons, see [toolbars](#).

Primary toolbar

The important item on this toolbar is the Template drop-down list.



Auto Template is the default setting, but you can select **Save / Delete Template** in order to create a template with the plot selections / datasets you prefer. This template can also be used in a custom worksheet to perform a decline analysis or ratio analysis. For more information, see the [Save Template dialog box](#).

Secondary toolbar

The secondary toolbar is above the plot, and in addition to the [common toolbar items](#), has the following items:

-  **Plot aggregate or individual entity production** — select aggregate, individual, or aggregate and individual data. The individual production of the selected entities are displayed in the plot for all plotted datasets. If you mouse over an entity, that well's production is displayed with a thicker line in the plot to help distinguish it from the other selections.
-  **Toggle Coloring by Entity or Dataset** — displays unique colors for entities / datasets. In other words, entities can use the default colors (red for gas, green for oil, etc.), or every dataset can have a unique color. (This feature is available in a diagnostic plot with multiple wells selected.)
- **Plot drop-down list** — select your [plot type](#) (semi-log vs. coordinate).

Context menus

Right-clicking within the *Data Viewer's* tree structure displays the same context menu as for a [pane](#).

Right-clicking within the Diagnostic plot (the main pane) displays [plot options](#).

Save Template dialog box

This dialog box is commonly used when you save, delete, or rename a template on the [Diagnostics tab](#).

Tip: All templates are user-specific. Therefore, any templates you create are not seen by other users in a multi-user environment. Note that templates exist in more places than just the Diagnostics tab. For example, templates also exist in the [Attributes tab](#) and [Results tab](#).

- **Name** — type a name for your template.
- **Worksheet Category** — select the appropriate worksheet category from the drop-down list (that is, Decline, Ratio Analysis, or Custom). After you click **Save**, the template is available for the new worksheets you create in the respective categories.

For example, if you are saving a template for the Decline category, you can customize these things in your template:

- You can set your rate (operated vs. calendar rate), and after adding a new decline worksheet, you can select the template and your decline worksheet initializes with that rate type.
- You can set any individual axis type to log-log (vs. coordinate) by right-clicking it.

To rename a template, select it in the Existing Templates box and type a new name in the Name field; click **Save**.

To delete a template, select it in the Existing Templates box and click **Delete**.

Economics

The Economics tab displays the economics for a well, scenario, or group of wells on a monthly basis, and you can run economics for multiple cases with multiple wells. Economics are calculated on a monthly basis by:

- taking the estimated production from decline curve analysis
- multiplying the production volume by the oil, gas, condensate, water, or BOE price that applies to the well at that month
- subtracting fixed and variable expenses
- calculating net revenues for the month

Note: Economics works with your Harmony Forecast™ license.

After clicking **Add Case**, the Case section opens. Click the inverted chevron icon () to open the case section.

Case

In this section, you can type a name for your economics scenario and add notes. Only one case can be open at a time.

A case can be added to a single entity or multiple entities.

Case — the title for your economics scenario. You can rename your case by clicking the Case field and typing a new name, or you can leave the default name. However,

you cannot have cases with the same name. If you rename a case, its order in the list of cases is automatically resorted alphabetically.

Notes — (optional) click this field to begin typing your notes.

The effective date and duration date are displayed in gray text below the toolbar icons. These dates are automatically taken from the production data you select in the Forecast section. For example, if you have a gas forecast that ends earlier than an oil forecast, the duration date is extended to match the oil forecast's end date for the analysis.

Toolbar

These icons are displayed at the top of the Case section:

 **Delete Case** — removes the currently selected case. If you delete the last case, your settings are reset to the default blank settings (the initial view).

 **Copy Case** — creates a duplicate of the currently selected case. The name is appended with the word "Copy".

 **Show / Hide Case** — toggle between showing or hiding the plot / grid for the currently selected case.

Discount Rate

The discount rate is a percentage discount, which is applied per year. This adjustment applies to your monthly cash flows received in the future to show its present value.

Type your annual discount rate for your case. The default value is 10%.

Forecast

In this section, up to five fluids can be displayed: oil, gas, condensate, barrel of oil equivalent (BOE), and water.

Your forecast is selectable from the existing decline analyses you have for the currently selected entity.

Select forecast data — select from the drop-down list. If there is an issue with your selection, the Fluid table below displays an error message (for example, invalid forecast, no forecast, etc.).

Note: Forecast volumes are only displayed for the fluids (that is, oil, gas, or BOE) that apply to the currently selected entity, and you can only select one forecast (not one forecast for each fluid).

Price & Revenue

In this section, up to five fluids can be displayed: oil, gas, condensate, BOE, and water.

Type your price, percentage of escalation / year, and your revenue is automatically calculated.

Revenue represents money you have earned *before* any expenses are accounted for.

 **Edit Price Deck** — opens the Enter Price Decks dialog box. Click this icon to paste values from an existing price deck, or type prices for your fluids. Note that if your price deck has an end date that falls short of the duration date of the forecast for your analysis, the last value in the Price Deck table is used for the remainder of the forecast period. If you paste content with more rows than are automatically displayed in the Price Deck table, note that additional rows are automatically added.

Tip: To decouple your case from a price deck, you need to delete the content in the Enter Price Decks dialog box. Then, you can type a price and percentage of escalation for your fluids.

Capital Expenses

Capital expenses represent investments that generate benefits for more than one period (for example, drilling, completions, tanks, buildings, etc.).

Tip: For upfront costs, leave the Date field blank. These costs are not included in the net present value (NPV) calculation.

Description — type a name for your capital expense.

Date — select a month from the calendar. Note that you must enter a date between the effective date and duration date for your economic analysis.

Dollar Amount — type a value for your capital expense.

 **Delete icon** — deletes the currently selected capital expense.

 **Add icon** — adds a new capital expense item.

Operating Costs

Operating costs represent expenditures that generate a benefit for the current period (for example, labor, maintenance, water disposal, etc.).

Description — type a name for your operating cost.

Dollar Amount — type a value for your operating cost.

Operating Cost Type — select from the drop-down list (that is, \$ / month, \$ / year, \$ / bbl, \$ / Mscf).

 **Delete** icon — deletes the currently selected operating cost.

 **Add** icon — adds a new operating cost item.

From — select a month from the calendar. Note that you must enter a date between the effective date and duration date for your economic analysis.

to — select a month from the calendar. Note that you must enter a date between the effective date and duration date for your economic analysis.

Note: If no dates are selected, by default, the effective date and duration date are used.

Taxes & Royalties

Taxes and royalties are calculated as percentages for the following categories:

Severance Tax — type your percentage. This tax is calculated based on oil & gas earnings *before* deductions for operating costs, and is also known as the production tax.

Ad Valorem Tax — type your percentage. This "according to the value" tax is calculated based on local taxes (for example, metro district tax, county tax). It is calculated based on revenue less the severance tax.

Royalties — type your percentage. This tax is calculated based on the ongoing right to use certain properties or assets. This tax may be based on a percentage of revenues, or a fixed price per unit sold.

Note: Taxes and royalties are calculated for the duration of the forecast, not annually.

Working Interest

Type your percentage of working interest for revenue and operating costs, which applies for the entire course of the project.

If you want to apply your operating interest to all capital expenses, click this checkbox.

Cumulative Net Cash Flow

This represents a summation of all the values for your case.

Important metrics

These metrics are displayed at the bottom of the plot:

Net Present Value (\$) (NPV) — provides the dollar value of a project taking into account the time value of money.

Discounted Payout — the length of time it takes in months to pay back the original investment. If you are running economics on an existing well, the discounted payout is zero.

Internal Rate of Return (IRR) — measures the potential profitability of a project. This metric is a discount rate that measures the percentage of return needed in order for the project to break even (where NPV is equal to zero). IRR is used to evaluate the attractiveness of a project, and is also known as the discounted cash flow rate of return. Generally, if the IRR is a high percentage, this indicates that you have a good project to invest in.

Plot / grid

The cash-flow plot is displayed in the main pane of the Economics window and has the following icons:



Show Plot — displays a plot view for your case. Up to 10 cases can be plotted with cumulative and periodic cash flows. If you plot more than 10 cases, only the cumulative values are displayed. Note that the active case is displayed in bold on the plot.



Show Grid — displays a tabular view for your active case, which can be copied and pasted, or exported as a .csv file.



Export to .csv — (only visible when the Show Grid icon is selected) copies your tabular data to a .csv file.



Rescale plot to show all data — (only visible when the Plot icon is selected) automatically fits all your data to the plot.

The following drop-down list items are only visible when the Plot icon is clicked:

Cumulative and Periodic Cash Flows — displays both the cumulative cash flow and period cash flow on the same plot.

Periodic Series Cash Flows — depending on how you scale the resolution on the x-axis, cash flow is displayed in a bar graph by month, quarter, year, or every five years.

Cumulative Series Cash Flows — displays an aggregate of cash flows in a line graph. The point where the line graph crosses the x-axis is the break-even point.

Y-axis icons

These icons are displayed when you hover your mouse over the y-axis:



y-axis panning — visible when you hover over the middle of the y-axis, and enables you to pan the axis up and down.



y-axis panning with a lock on the top of the top of the axis — visible when you hover over the lower part of the y-axis, and enables you to pan the axis up and down, while you maintain the top value on the y-axis.



y-axis panning with a lock on the bottom of the axis — visible when you hover over the upper part of the y-axis, and enables you to pan the axis up and down, while you maintain the lower value on the y-axis.

X-axis icons

These icons are displayed when you hover your mouse over the x-axis:



x-axis panning — visible when you hover over the middle of the x-axis, and enables you to pan the axis left and right.



x-axis panning with a lock on the right of the axis — visible when you hover over the left-side of the x-axis, and enables you to pan the axis left and right, while you maintain the value on the right.

 **x-axis panning with a lock on the left of the axis** — visible when you hover over the right-side of the x-axis, and enables you to pan the axis left and right, while you maintain the value on the left.

Editors

To open the Editors pane, select an entity (in either Entity Viewer, or in the GIS map), click the **Analysis** tab, and then click the **Editors** sub-tab.

Tip: You cannot use the editors with group selections.

Harmony Enterprise has the following editors:

- [Properties](#)
- [Wellbore](#)
- [Production](#)
- [Static Pressure](#)
- [Multilayer Allocation](#)

Properties editor

In the Properties editor (located within the [Editors pane](#)), you can set properties and correlations for the formation and fluids, as well as reservoir properties.

Toolbars

There are three toolbars associated with the Properties editor: primary, secondary, and plot toolbars.

Primary

The primary toolbar has the following icons:

-  **Change plot options** — opens the Plot Options dialog box where you can set your minimum and maximum pressure, as well as your step size. You also have the option to display numerical or non-numerical analysis properties.

-  **Copy to / paste from clipboard** — click this icon to copy / paste properties between different wells.
-  **Calculate sandface pressure** — calculates sandface pressure based on given wellhead pressure and fluid rates. These calculations use fluid properties set in the Properties editor. If you change fluid properties, you need to re-run sandface pressure calculations by clicking this icon.

Secondary

The secondary toolbar is located to the right of the Editors pane, and has the following icons:

-  **View Data** — toggle between a table view and a plot view.
-  **Toggle Units** — toggle between metric and field (imperial) units.
-  **Change Bottom Left Plot** — (gas properties only) toggles the bottom left plot between the Vaporized Oil Ratio (R_v) and Gas Compressibility (c_g).

Plot

The plot toolbar is located directly above the plots in the main pane. For more information, see [plot toolbars](#).

Selection tree

The selection tree is located directly below the primary toolbar. After you select a certain node in the selection tree, a corresponding set of properties is displayed in the pane to the right (for example, if you select the Gas node, gas properties are displayed in the right pane). The Reservoir Properties pane is located below the selection tree.

The screenshot displays the 'Editors' window in 'Non-numerical Property Mode'. The left pane shows a tree view where 'Gas' is selected. The right pane shows various property correlation dropdowns, with 'Gas Properties' selected. Below these are input fields for gas gravity (G = 0.883) and gas impurities (CO₂ = 0.50%, H₂S = 0.00%, N₂ = 0.97%). The bottom section shows calculated 'Properties at p_i & T_R'.

Reservoir Properties		
P_i	8169.83	psi(a)
T_R	271.0	°F
h	50.0	ft
r_w	0.350	ft
λ_t	7.00	%
S_{gl}	0.00	%
S_{oi}	70.00	%
S_{wi}	30.00	%
c_{ri}	5.64e-06	1/psi
c_{ti}	1.16e-05	1/psi

Gas Properties		
G	0.883	

Gas Impurities		
CO ₂	0.50	%
H ₂ S	0.00	%
N ₂	0.97	%

Critical Properties		
T_c	420.6	°R
P_c	652.54	psi(a)

Properties at p _i & T _R		
Z_i	1.280	
B_{gi}	3.23e-03	ft ³ /scf
c_{gi}	5.17e-05	1/psi
μ_{gi}	0.0349	cP
ρ_{gi}	20.81	lb/ft ³

Gas properties

After you select **Gas** in the selection tree, you can select a **PVT** correlation, or custom table from the **PVT Correlation** drop-down list. Use the correlation selection for gas PVT to select the appropriate correlation. If you select **Custom Table**, you can enter or import your own data.

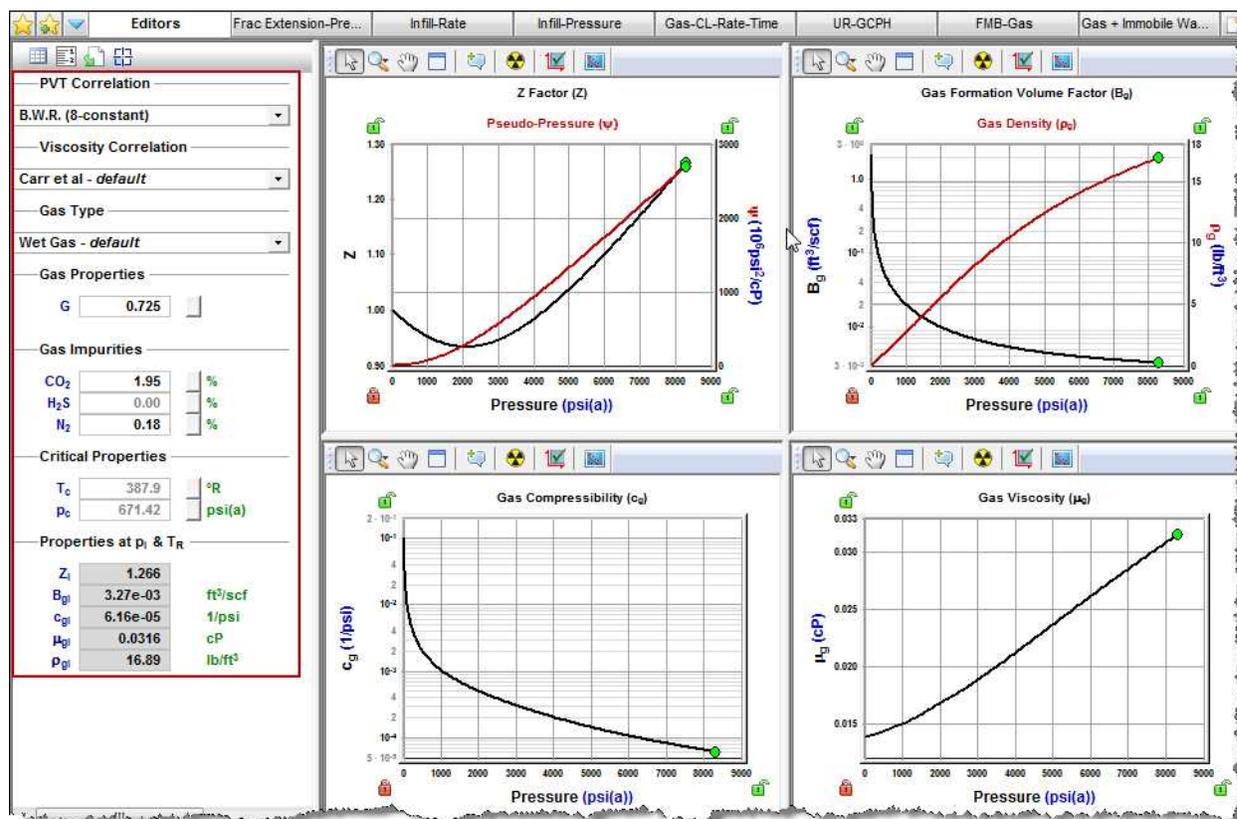
Similarly, you can select a viscosity correlation, or custom table from the **Viscosity Correlation** drop-down list. Use the correlation selection for gas viscosity to select the appropriate correlation.

From the **Gas Type** drop-down list, you can select dry gas, wet gas, or liquid-rich gas.

Gas properties as functions of pressure are calculated based on selected correlations, using the values set for gas gravity (G), critical temperature (T_c), and critical pressure (p_c). You can enter these values, or leave the default values calculated by Harmony Enterprise.

The calculated properties at initial conditions (p_i and T_R) are displayed in the **Properties at p_i & T_R** section.

Gas properties vs. pressure are plotted, including Z , ψ , B_g or B_{gd} , ρ_g , c_g , R_v , V_L / V_{sat} , and μ_g .



Additional properties for liquid-rich gas

If the Gas Type is set to **Liquid-Rich Gas**, additional properties are displayed:

- **Vaporized Oil Ratio Correlation** — defines the amount of liquid vaporized in gas as a function of pressure.
- **p_{dew}** — dew point pressure. It should be set to the same value as the bubble point pressure defined under Oil / Condensate properties.
- **CGR_i** — condensate gas ratio at the separator.
- **γ_{cond}** — condensate gravity. It should be set to the same value as the oil gravity defined under Oil / Condensate properties.
- **T_{sep} , p_{sep}** — temperature and pressure at the separator.
- **RGRF** — recombined gas rate factor. We recommend keeping the default value.
- **G_r** — recombined gas gravity. All gas property functions are generated based on this gas gravity (as well as critical temperature and pressure).

PVT Correlation		
Custom Table	▼	
Viscosity Correlation		
Carr et al - default	▼	
Gas Type		
Liquid-Rich Gas	▼	
Vaporized Oil Ratio Correlation		
Ovalle et al. (Gas Condensate)	▼	
Gas Properties		
G	0.650	
p_{dew}	435.11	psi(a)
CGR_i	300.0	bbl/MMscf
γ_{cond}	45.0	°API
T_{sep}	100.0	°F
p_{sep}	100.00	psi(a)
RGRF	1.207	
G_r	1.462	

Correlation selection for gas

There are two correlation selections for gas: PVT and viscosity.

Note: Unless otherwise noted, all percentages are in mole %.

PVT

Various gas PVT correlations are described below:

- **B.W.R. (Table)** — the Benedict-Webb-Rubin equation is an empirical relationship that predicts the state of liquids and gases. Tables were developed for approximately 50 substances, mostly hydrocarbons that related gas density, formation volume factor, and temperature to pressure.
- **B.W.R. (8-constant)** — the Benedict-Webb-Rubin (8-constant) equation of state developed a set of generalized coefficients in order to be applied to all types of gases.
- **B.W.R. (11-constant)** — the Benedict-Webb-Rubin (11-constant) equation of state is a further refined method to predict the state of liquids and gases. It is used for all types of gases, and uses 11 empirical constants to achieve a more accurate interpolation of the data.
- **AGA8 Detail** — calculates the Z-factor based on the physical chemistry of the gas components at specified temperatures and pressures. It can be used when the exact composition (fraction mole percents) of the gas is available.
- **Carbon Dioxide (Table)** — the Carbon Dioxide tables are for calculating a Z factor for 100% CO₂ content.
- **Nitrogen (Table)** — the Nitrogen tables are for computing a Z factor for 100% N₂ content.
- **Hydrogen Sulfide (Table)** — the Hydrogen Sulfide tables are for computing a Z factor for 100% H₂S content.
- **Custom Table** — you can enter laboratory measurements for a gas Z factor or formation volume factor. The Z factor is calculated from the formation volume factor or vice versa. Gas compressibility is subsequently calculated from these two values.

Viscosity

Various gas viscosity correlations are described below:

- **Carr et al.** — developed to predict the viscosity of gas hydrocarbon mixtures for temperatures between 32°F and 400°F, and pressures up to 12,000 psi. It applies to both sweet and sour gas, and is designed to handle non-hydrocarbon components (CO₂, H₂S, N₂) in concentrations of up to 15% each.
- **Lee, Gonzalez, Eakin** — applies to sweet gas, but does not account for the presence of non-hydrocarbon components. It is applicable for a pressure range of 100 - 8,000 psi, and temperatures between 100°F - 340°F. It is less accurate for gases with a specific gravity above 1.0.

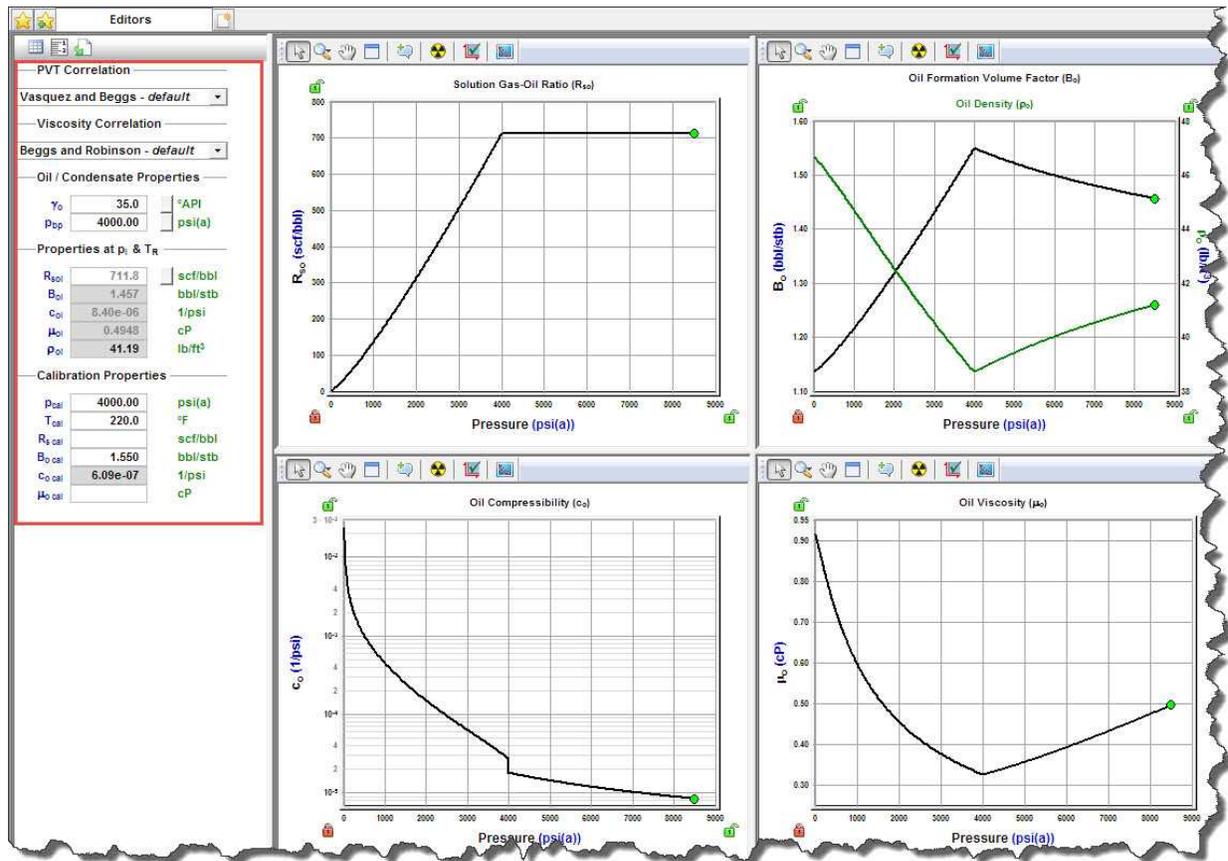
- **Optimized Lee et al.** — developed using the Lee, Gonzalez, and Eakin method, but uses an optimized temperature history to achieve more accurate results, thus resulting in different coefficients in the equations. (There is less than a 5% difference in extreme cases from the original correlations.)
- **Lucas et al.** — uses the method of corresponding states to calculate gas viscosity. It is better suited for higher density gases at lower pressures.
- **Custom Table** — you can enter custom gas viscosity values from laboratory measurements.

Oil / condensate properties

After you select **Oil / Condensate** in the selection tree, you can select a PVT correlation, constant properties, or custom table from the **PVT Correlation** drop-down list. Similarly, you can select a correlation, constant properties, or custom table from the **Viscosity Correlation** drop-down list.

Use the [correlation selection for oil](#) to select the appropriate correlation. If you select **Custom Table**, you can enter or import your own data.

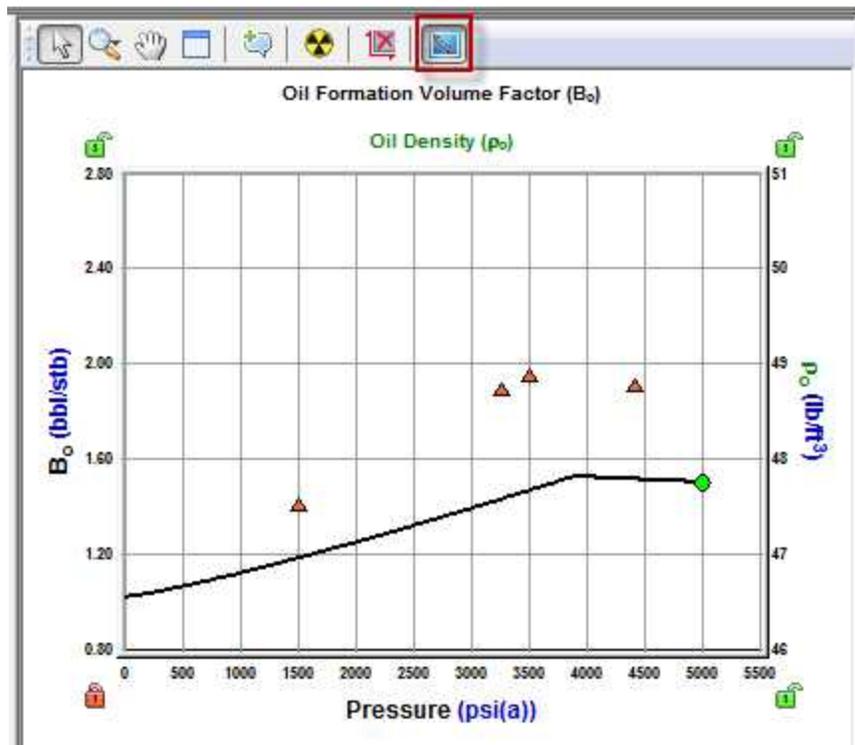
Oil properties vs. pressure are plotted, including R_{so} , B_o , ρ_o , c_o , and μ_o . The calculated properties at p_i and T_R are also displayed.



Calibration properties for oil

This functionality is used to calibrate existing correlations for oil PVT and viscosity to anchor them to a certain (known) value. This is usually done when you have some custom data for oil properties, and want to calibrate oil correlations to match custom data as closely as possible.

To see if the selected correlation is close to the custom data you entered, click the **Show the Custom Data Points** icon on the plot toolbar.



In the Calibration Properties section, these fields are displayed:

- p_{cal} and T_{cal} — calibration pressure and temperature.
- $R_{s cal}$ — the correlation curve for the solution gas-oil ratio (R_s) shifts such that $R_s(p=p_{cal}, T=T_{cal})=R_{s cal}$.
- $B_{o cal}$ — the correlation curve for the oil formation volume factor (B_o) shifts such that $B_o(p=p_{cal}, T=T_{cal})=B_{o cal}$.
- $c_{o cal}$ — the correlation curve for oil compressibility (c_o) shifts such that $c_o(p=p_{cal}, T=T_{cal})=c_{o cal}$.
- $\mu_{o cal}$ — the correlation curve for oil viscosity (μ_o) shifts such that $\mu_o(p=p_{cal}, T=T_{cal})=\mu_{o cal}$.

Calibration Properties		
p_{cal}	5000.00	psi(a)
T_{cal}	120.0	°F
$R_{s cal}$		scf/bbl
$B_{o cal}$	1.500	bbl/stb
$c_{o cal}$		1/psi
$\mu_{o cal}$	0.800	cP

Correlation selection for oil

There are two correlation selections for oil: PVT and viscosity.

PVT

Various oil PVT correlations are described below:

- **Vasquez and Beggs** — developed from field data (from locations all over the world). It is generally applicable for all oil types, and covers a wide range of pressures, temperatures, and oil properties.
- **Al-Marhoun** — developed for Saudi Arabian oils. It is valid for all types of gas-oil mixtures ranging from 14 - 45 °API.
- **De Ghetto et al.** — developed for heavy oils ($10 < \text{°API} < 22.3$) and extra-heavy oils ($\text{°API} < 10$) from the Mediterranean Basin, Africa, and the Persian Gulf. It requires separator pressure and temperature.
- **Glaso** — developed for North Sea oils. It is suitable for oil mixtures ranging from 22-48 °API, and is valid for all types of oil and gas mixtures after correcting for non-hydrocarbons in the surface gases, and the paraffinicity of the oil.
- **Hanafy et al.** — developed for Egyptian oils gathered from the Gulf of Suez, Western Desert, and Sinai regions. It is independent of oil gravity and reservoir temperature. Although the authors claim that the correlations are applicable to a wide range of crude oils ranging from heavy to volatile oils (14.3 – 47 °API), it appears to be more applicable to light oils.
- **Petrosky and Farshad** — developed for Gulf of Mexico oils gathered from offshore regions in Texas and Louisiana. It is applicable for oil mixtures ranging from 16 - 45 °API, and provides improved results for the Gulf of Mexico oils compared to Standing, Vasquez and Beggs, Glaso, and Al-Marhoun correlations.
- **Standing** — developed for California oils. It is applicable for oil mixtures ranging from 16 - 64 °API.
- **Velarde et al.** — developed for black oils. It is applicable for oil mixtures ranging from 12 - 55 °API.
- **Constant Properties** — you can enter values for the oil compressibility, solution gas-oil ratio, and oil formation volume factor at initial reservoir conditions.
- **Custom Table** — you can enter laboratory measurements for the oil compressibility, solution gas-oil ratio, and oil formation volume factor.

Viscosity

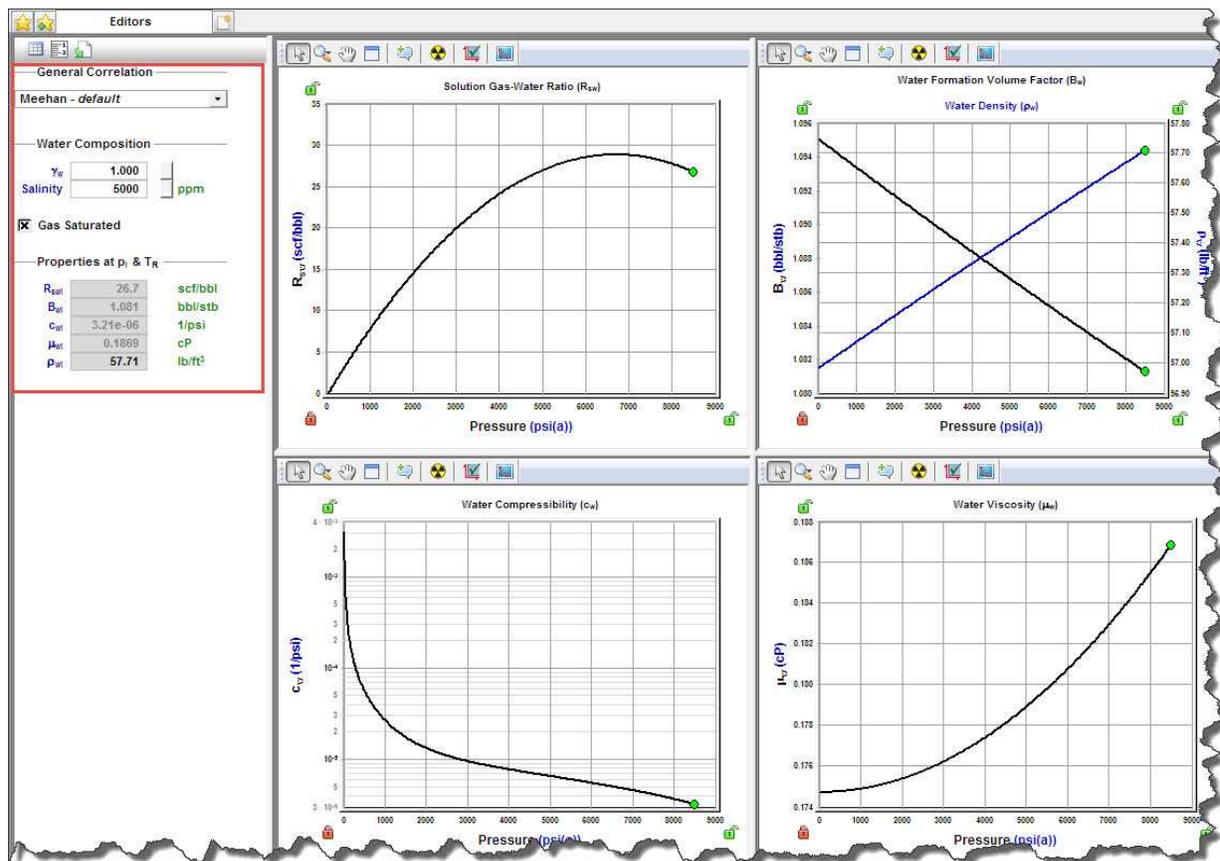
Various oil viscosity correlations are described below:

- **Beggs and Robinson** — developed from field data (from locations all over the world). It is generally applicable for all oil types, and covers a wide range of pressures, temperatures, and oil properties.
- **De Ghetto et al.** — developed for heavy oils ($10 < \text{°API} < 22.3$) and extra-heavy oils ($\text{°API} < 10$) from the Mediterranean Basin, Africa, and the Persian Gulf. It requires separator pressure and temperature.
- **Hanafy et al.** — developed for Egyptian oils gathered from the Gulf of Suez, Western Desert, and Sinai regions. It is independent of oil gravity and reservoir temperature. Although the authors claim that the correlations are applicable to a wide range of crude oils ranging from heavy to volatile oils ($14.3 - 47 \text{ °API}$), it appears to be more applicable to light oils.
- **Khan et al.** — developed using oil samples collected from Saudi Arabian reservoirs. It gives more accurate predictions for Saudi Arabian oils, compared to the Beggs and Robinson.
- **Ng and Egbogah** — this correlation contains two methods for calculating dead oil viscosity using a modified Beggs and Robinson viscosity correlation, and a correlation that uses the pour point temperature, which is the lowest temperature at which the oil is observed to flow when cooled. The purpose of introducing the pour point temperature into the correlation is to reflect the chemical composition of crude oil into the viscosity correlation. To obtain the viscosity for live oils, the dead oil correlations are used with the Beggs and Robinson viscosity correlation. This correlation is applicable for oil mixtures ranging from $5 - 58 \text{ °API}$.
- **Constant Properties** — you can enter a value for oil viscosity at initial reservoir conditions.
- **Custom Table** — you can enter laboratory measurements for oil viscosity.

Water properties

After you select **Water** in the selection tree, you can select a correlation, constant properties, or a custom table from the **General Correlation** drop-down list.

Water properties vs. pressure are plotted, including R_{sw} , B_w , ρ_w , c_w , and μ_w . The calculated properties at p_i and T_R are also displayed.



Gas lift properties

After you select **Gas Lift** in the selection tree, simplified gas properties are listed, to be used on analyses with gas lift. Only limited options are available for PVT Correlation, Viscosity Correlation, and Gas Type.

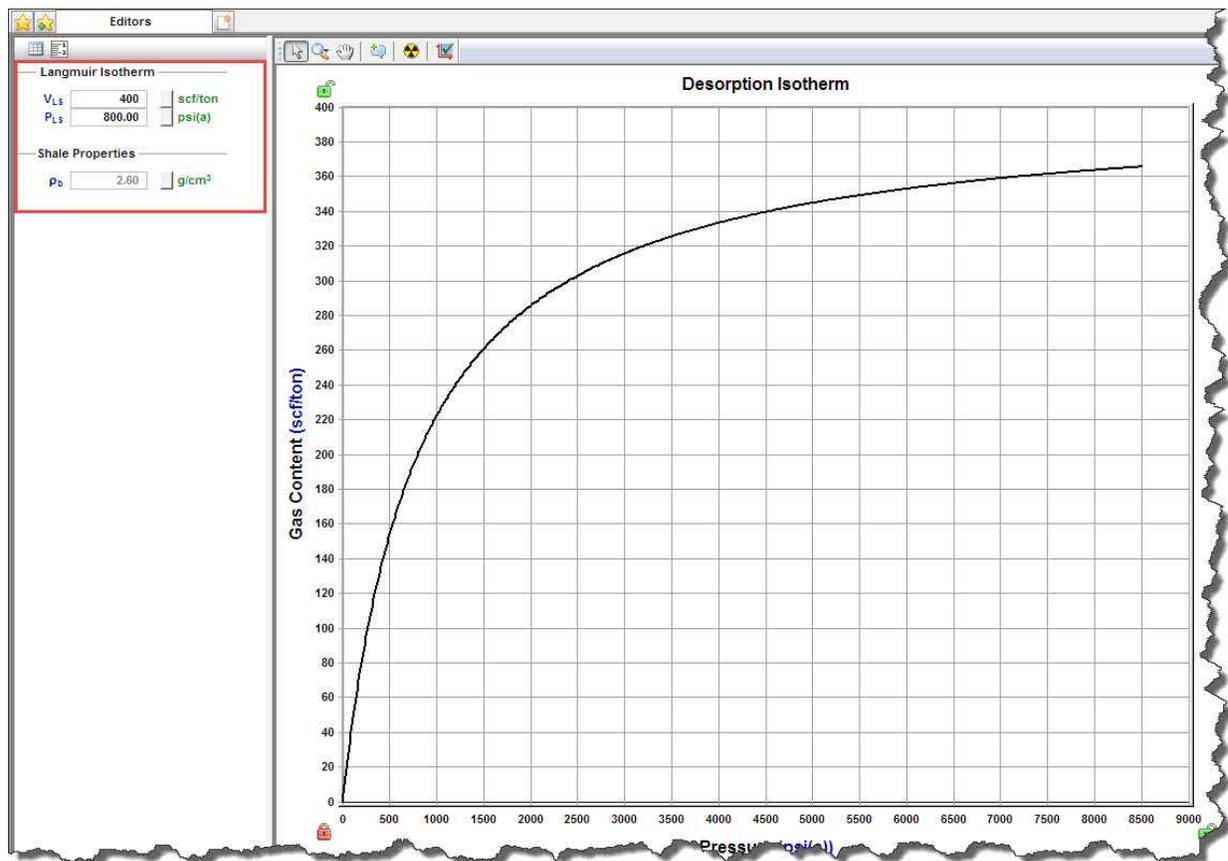
Note: If you want to change the PVT Correlation or Viscosity Correlation for your gas lift, you must change these selections in gas properties.

Adsorption properties

After you select **Adsorption** in the selection tree, these properties are displayed:

- V_{LS} , P_{LS} — Langmuir volume and Langmuir pressure (for shale). For more information, see Langmuir isotherm.
- ρ_b — bulk density (for shale).

Gas content vs. pressure is plotted.



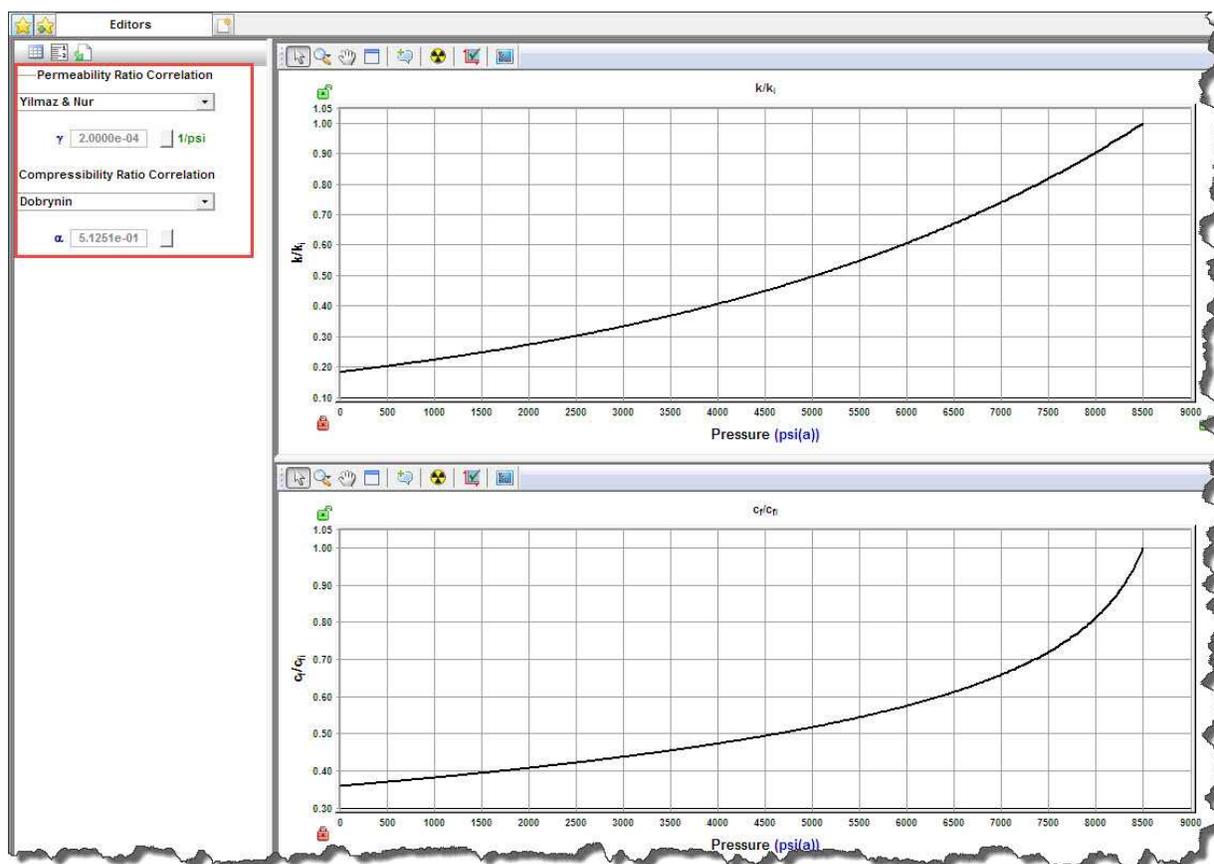
Geomechanical properties

After you select **Geomechanical** in the selection tree, you can set how rock properties (permeability and formation compressibility) vary with pressure.

- **Permeability Ratio Correlation drop-down list** — select a correlation for the variation of permeability with pressure.
- **Compressibility Ratio Correlation drop-down list** — select a correlation for the variation of formation compressibility with pressure.
- α — Biot effective stress coefficient (for Dobrynin correlation). The larger this parameter is, the more permeability and formation compressibility vary with pressure.
- γ — permeability modulus (for the Yilmaz & Nur correlation). The larger this parameter, the more permeability varies with pressure.

For more information, see [Geomechanical reservoir models](#).

Geomechanical properties vs. pressure are plotted, including k / k_i and c_f / c_{fi} .



Relative permeability properties

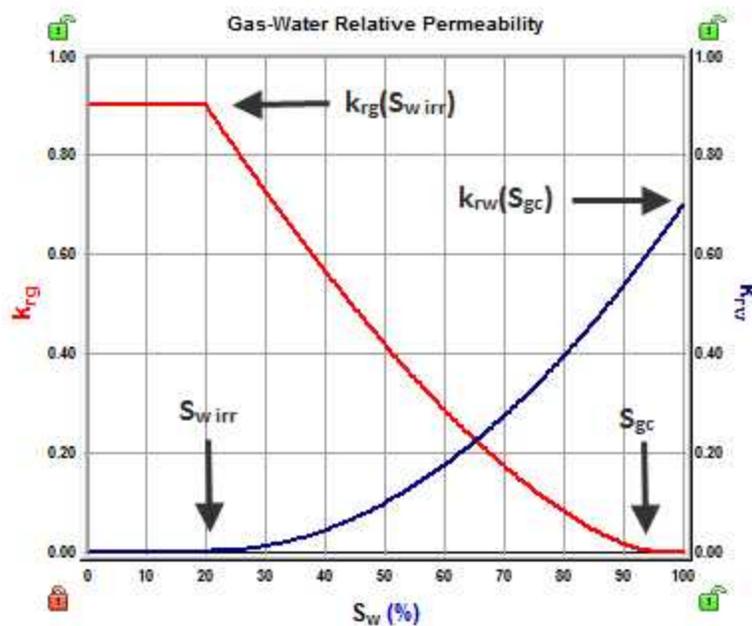
After you select **Relative Permeability** in the selection tree, you can set correlations and parameters describing relative permeability between different fluids flowing together.

- **2-Phase Model Correlation drop-down list** — select a relative permeability correlation. For more information, see relative permeability correlations.
- (located at the bottom of the pane) **3-Phase Model Correlation** — defines how given 2-phase relative permeabilities are combined to calculate permeability for each phase for the cases when all three phases (oil, gas, and water) are flowing together. For more information, see three-phase correlations.

Water-gas section

Parameters in the Water-Gas section describe relative permeabilities for the case when water and gas are flowing together:

- $S_{w\text{ irr}}$ — irreducible water saturation. This is the immobile water when gas is the displacing fluid.
- $S_{g\text{ c}}$ — critical gas saturation. This is the minimum saturation for gas to become mobile.
- $k_{rw}(S_{g\text{ c}})$ — water relative permeability at $S_{g\text{ c}}$.
- $k_{rg}(S_{w\text{ irr}})$ — gas relative permeability at $S_{w\text{ irr}}$.
- n_w — water relative permeability exponent. This parameter describes how much the water relative permeability curve bends.
- n_g — gas relative permeability exponent. This parameter describes how much the gas relative permeability curve bends.

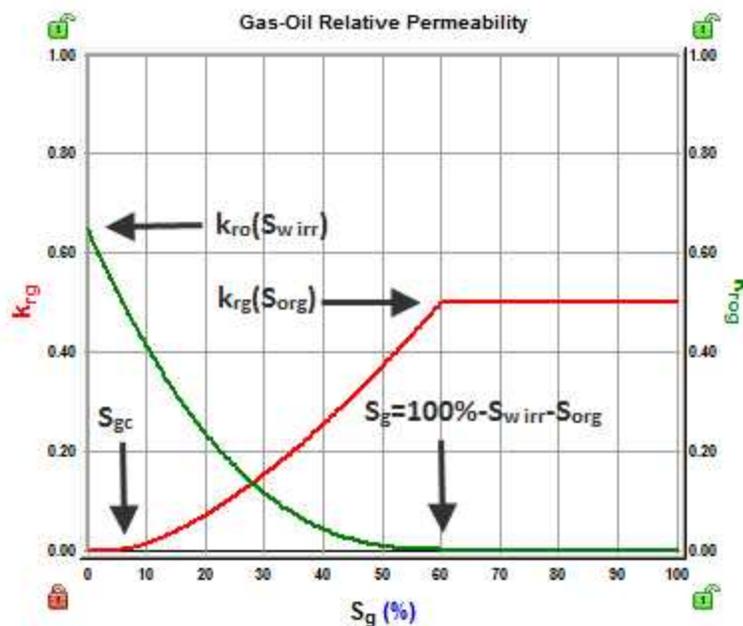


Oil-gas section

Parameters in the Oil-Gas section describe relative permeabilities for the case when oil and gas are flowing together:

- $S_{w\text{ irr}}$ — irreducible water saturation. This is the immobile water when oil or gas is the displacing fluid.
- $S_{o\text{ rg}}$ — residual oil saturation to gas. This is the immobile oil when gas is the displacing fluid.

- S_{gc} — critical gas saturation. This is the minimum saturation for gas to become mobile.
- $k_{ro}(S_{w\ irr})$ — oil relative permeability at $S_{w\ irr}$.
- $k_{rg}(S_{org})$ — gas relative permeability at S_{org} .
- n_{og} — oil relative permeability exponent to gas. This parameter describes how much the oil relative permeability curve bends.
- n_q — gas relative permeability exponent to gas. This parameter describes how much the gas relative permeability curve bends.

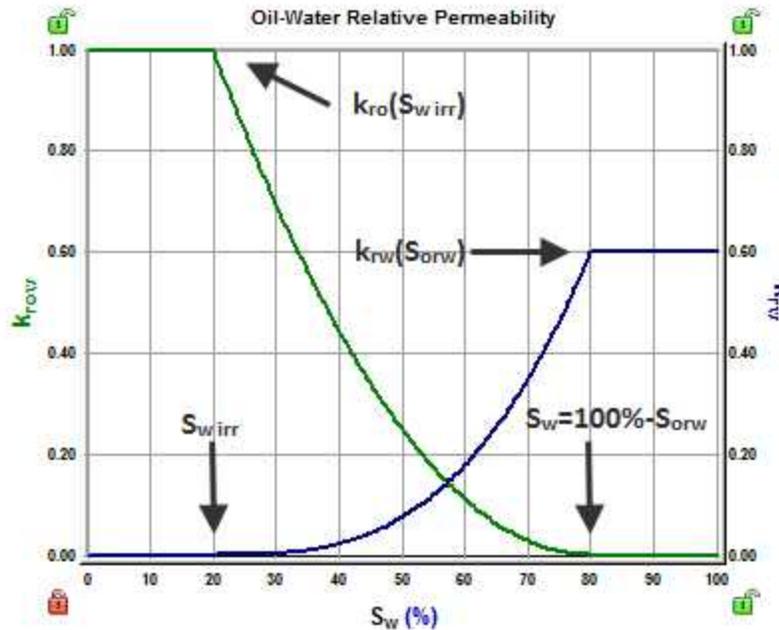


Water-oil section

Parameters in the Water-Oil section describe relative permeabilities for the case when oil and water are flowing together:

- $S_{w\ irr}$ — irreducible water saturation. This is the immobile water when oil is the displacing fluid.
- S_{orw} — residual oil saturation to water. This is the immobile oil when water is the displacing fluid.
- $k_{rw}(S_{orw})$ — water relative permeability at S_{orw} .
- $k_{ro}(S_{wirr})$ — oil relative permeability at S_{wirr} .

- n_w — water relative permeability exponent. This parameter describes how much the water relative permeability curve bends.
- n_{ow} — oil relative permeability exponent to water. This parameter describes how much the oil relative permeability curve bends.



Multilayer wells: Properties editor differences

Single-layer wells versus multilayer wells are contrasted below:

- The Properties editor is available to the well entity of a multilayered well, and it is also available to layer entities.
- Functionality changes for multilayer wells: You can type properties at the well level and at the layer level. The properties typed for a layer are used by that layer's analyses. However the sandface pressure calculations take its fluid properties from the well entity rather than attempting to mix fluid properties from the layers.

Note: Typing properties at the well level does not automatically propagate to the layer level, or vice versa.

Wellbore editor

In the Wellbore editor (located within the Editors pane), you can create multiple wellbore configurations for a well. Wellbore configurations are used to calculate flowing pressures in the Production editor. Configurations are assigned a date and are used in calculations until the date of the next configuration. Temperature and deviation surveys can also be added for the initial configuration. A schematic of the wellbore is displayed on the right side of this editor.

After you have entered completion data and set temperature gradients, this data can be used in analyses and pressure calculations.

Note: Many Reservoir analyses use sandface flowing pressures. In order to calculate sandface flowing pressures, you must enter wellbore information.

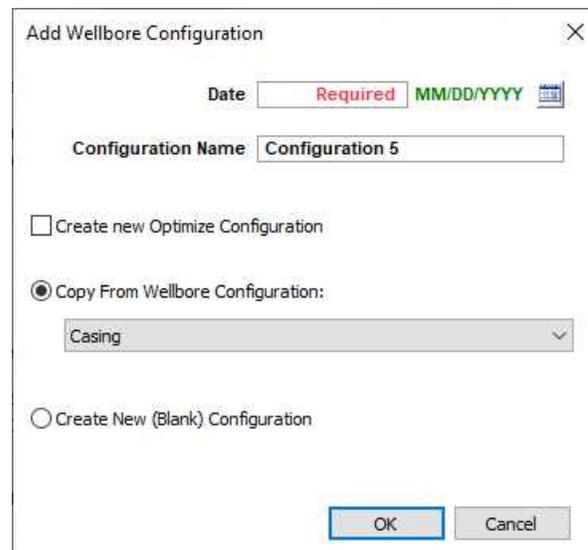
Toolbars

There are two toolbars associated with the Wellbore editor: primary and schematic.

Primary

The primary toolbar has the following icons:

-  **Add Configuration** — opens the Add Wellbore Configuration dialog box where you can select an existing wellbore or configuration to copy from, or create a blank configuration. Select either a regular configuration with a date or a Optimize Configuration.



Add Wellbore Configuration

Date: MM/DD/YYYY 

Configuration Name:

Create new Optimize Configuration

Copy From Wellbore Configuration:



Create New (Blank) Configuration

-  **Delete Configuration** — this icon is enabled after you select a wellbore in the Editors pane. If the initial configuration is removed, the next configuration is set as the Initial Configuration. When only one configuration exists, it cannot be deleted.

Note: Pressures are not updated after deleting a wellbore until the Calculate icon is clicked. If the Auto Calculate feature is enabled, pressures are recalculated when a wellbore is deleted.

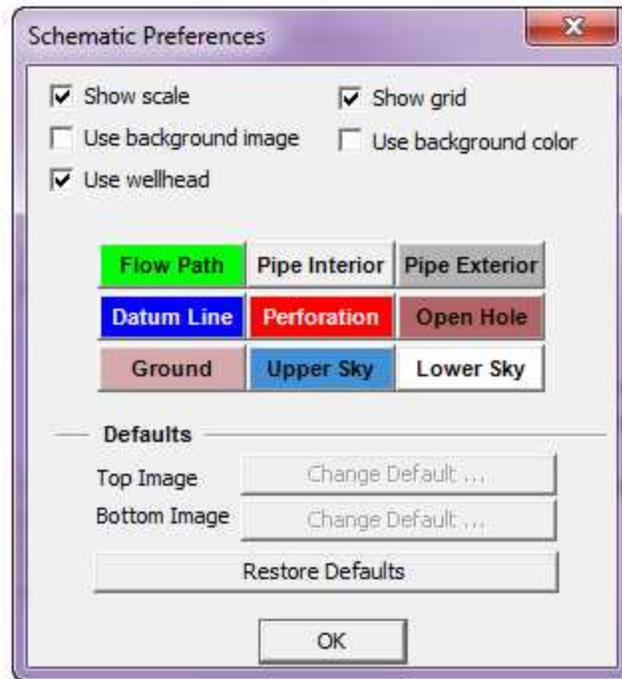
-  **Liquid Loading** — opens the Liquid Loading Parameters dialog box where you enter the required parameters:
 - select the correlation used to calculate liquid-loading conditions.
 - select the liquid type.
 - select how the critical gas rate used to determine liquid-loading conditions is calculated: at Datum, or at end of tubing (at EOT).
Note that for configurations with a casing flow path, the critical gas rate is always calculated at Datum.
-  **Calculate Sandface Pressure** — calculates sandface pressure each time you click this icon.
-  **Toggle Name / Date** — toggle between the name and date of the configuration in the pane below. This can also be set in the [Options dialog box | Wellbore node](#).
-  **Copy to / Paste from Clipboard** — copy / paste configurations.

Tip: To set various elevations (for example, ground level, kelly bushing), enter these values in the [Attributes tab](#).

Schematic

The schematic pane is located on the right-side of this editor in the Schematic pane, and has the following icon:

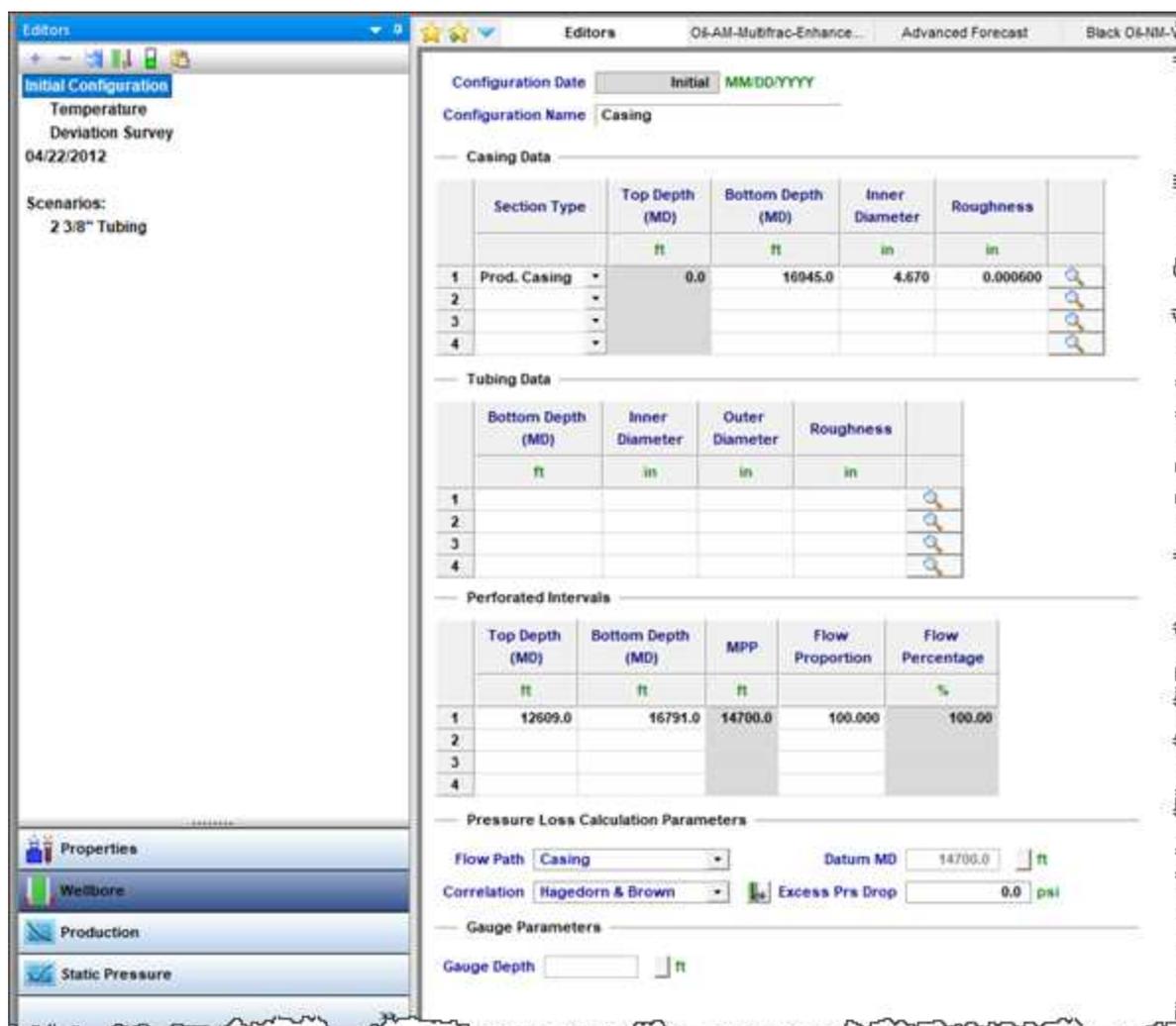
-  **Preferences** — opens the Schematic Preferences dialog box where you can customize your schematic.



Main pane

In the main pane, you can edit your wellbore configuration data, including tubulars, temperature, and deviation survey.

Click **Initial Configuration** in the Editors pane; then enter values in the Casing Data, Tubing Data, Perforation Intervals, and Pressure Loss Calculation Parameters areas.



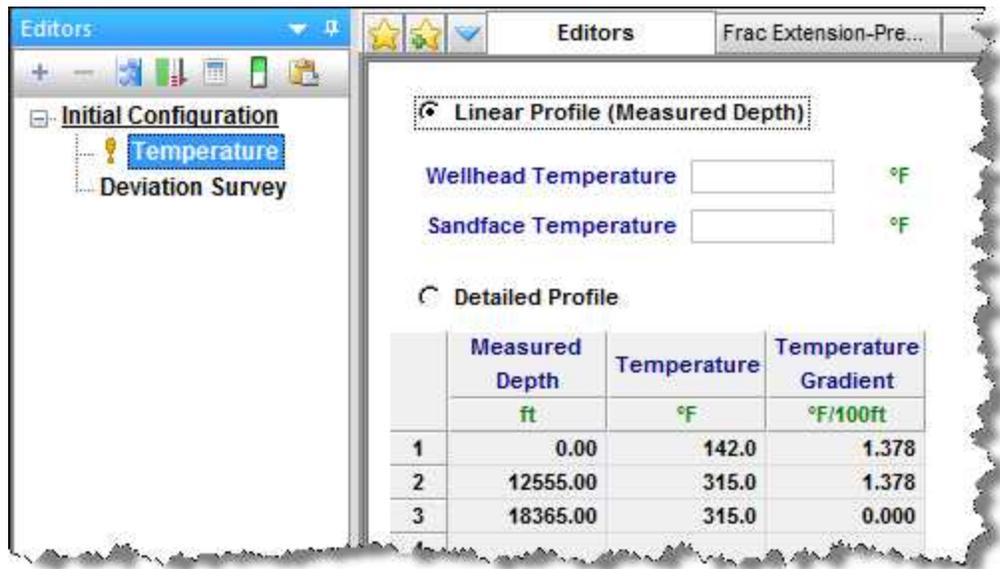
When entering casing or tubing data, clicking the  icon on the right-side of each row opens the Sizes dialog box, where common tubing / casing / pipe sizes can be selected from a list.

If you select **Pumping** in the **Flow Path** drop-down list and **Auto Template** is selected (default setting), these columns are displayed in the Production editor:

- Gas Volume
- Casing Pressure
- Pressure Source
- Active Pressure
- Calculated Sandface Pressure

- Liquid Level (MD)
- Average Liquid Gradient
- Gas Gradient
- Oil Gradient
- Water Gradient

Click **Temperature** in the Editors pane; then enter your temperature profile.



Click **Deviation Survey** in the Editors pane; then enter measured depth and TVD. In this way, you can emulate a horizontal or directional well. For a vertical well, deviation data is unnecessary.

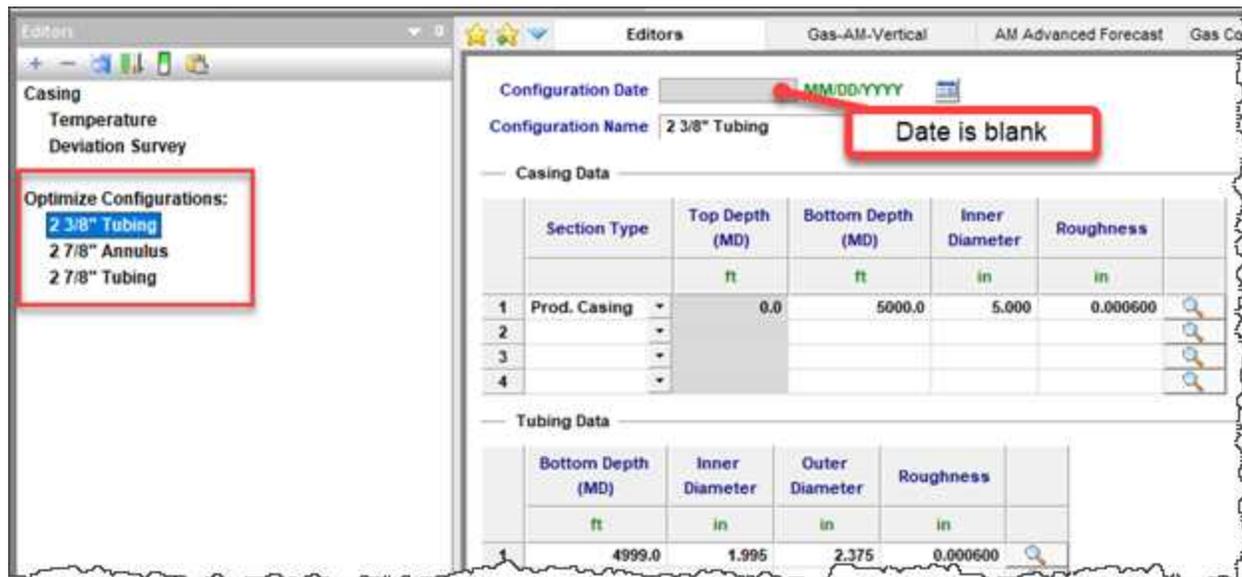
The screenshot shows a software interface with a sidebar on the left containing 'Initial Configuration', 'Temperature', and 'Deviation Survey'. The main window displays a table titled 'Deviation Survey' with the following data:

	Measured Depth	TVD	Deviation Angle	Easting	Northing
	ft	ft	°	ft	ft
1	1063.00	1062.82	1.1		
2	1155.00	1154.78	1.7		
3	1246.00	1245.63	3.3		
4	1429.00	1428.14	4.2		
5	1611.00	1609.62	4.3		
6	1793.00	1791.14	4.2		
7	1975.00	1972.67	4.1		
8	2158.00	2155.17	4.2		
9	2341.00	2337.69	4.2		
10	2524.00	2520.36	3.4		
11	2705.00	2701.17	2.6		
12	2887.00	2882.98	2.6		
13	3071.00	3066.83	2.3		
14	3255.00	3250.74	1.8		
15	3437.00	3432.69	1.3		
16	3618.00	3613.65	1.2		
17	3801.00	3796.63	0.8		

If you want to add a deviation survey with 3-dimensional data, enter your data in the Easting and Northing columns.

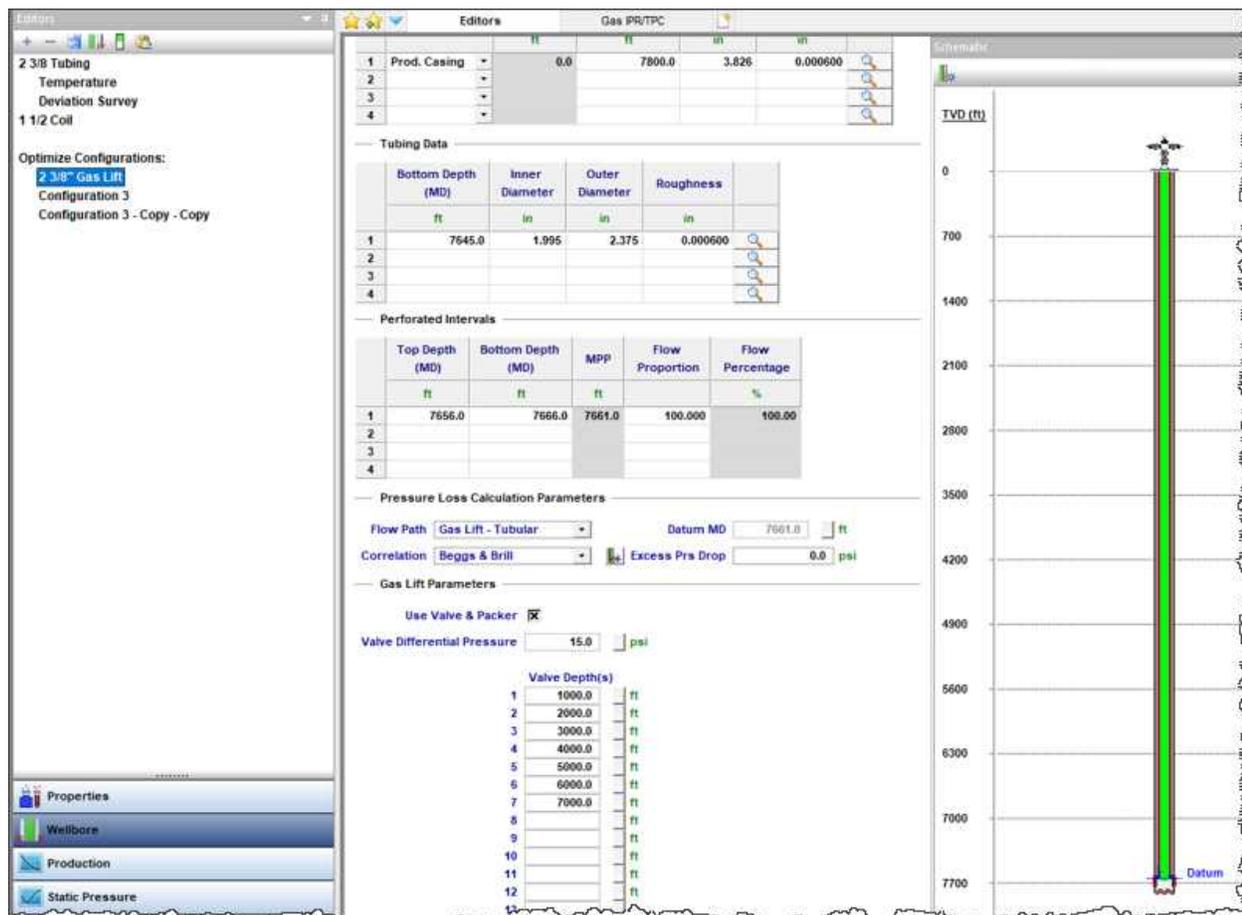
Optimize Configurations

When performing comparisons of completion changes within Optimize worksheets, you may want to consider hypothetical or future changes without affecting the sandface pressure calculations within the production history. This can include different sizes of tubing or variations on the pressure loss correlation. These can be created as Optimize Configurations, which do not have dates and are only available to Optimize analyses.



Optimize Configurations also contain more robust inputs for Artificial Lift calculations within Optimize worksheets.

Gas Lift: Optimize Configurations support multi-valve Gas Lift configurations. Set the Flow Path of an Optimize Configuration to Gas Lift - Tubular or Gas Lift - Annular. Type up to 15 unique valve depths, as well as a valve differential pressure. These configurations can be used In the IPR / TPC and Flowing Gradient worksheets to evaluate and compare gas lift configurations and production response to gas lift.

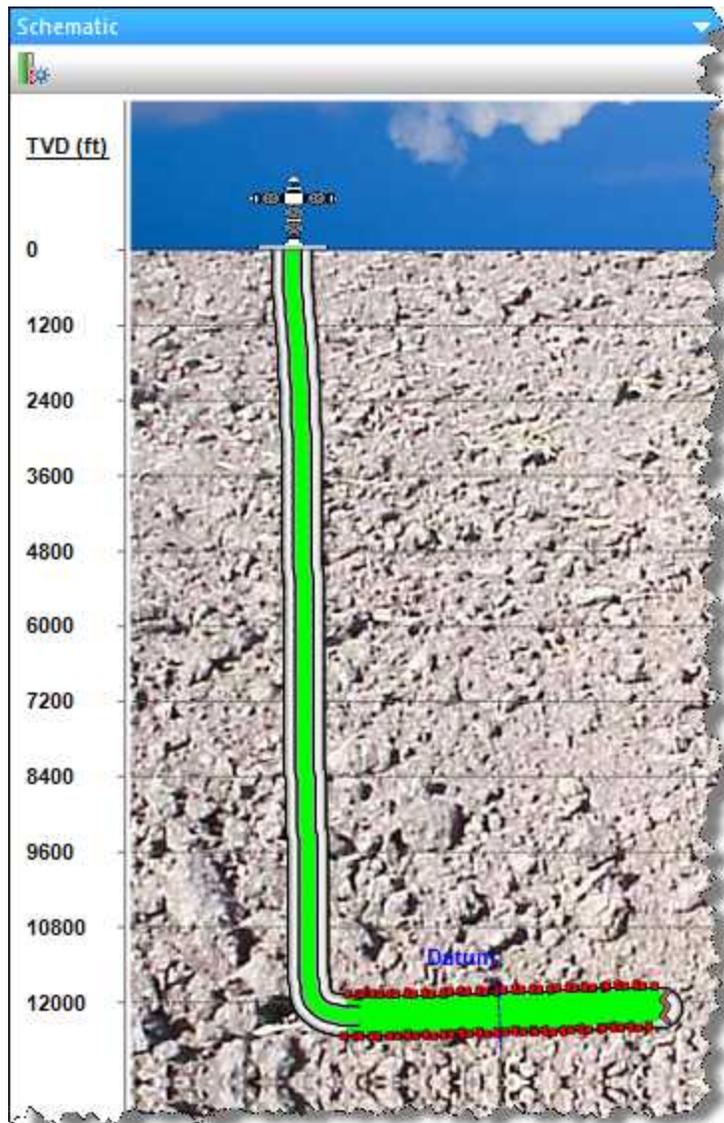


Electrical submersible pumps (ESPs)

Optimize Configurations now support the addition of ESP calculations in Optimize worksheets. Set the Flow Path Optimize Configuration to Pumping. In the Pumping Parameters section below, select a Pump to apply to this Optimize Configuration. The pump depth is automatically set to the End of Tubing.

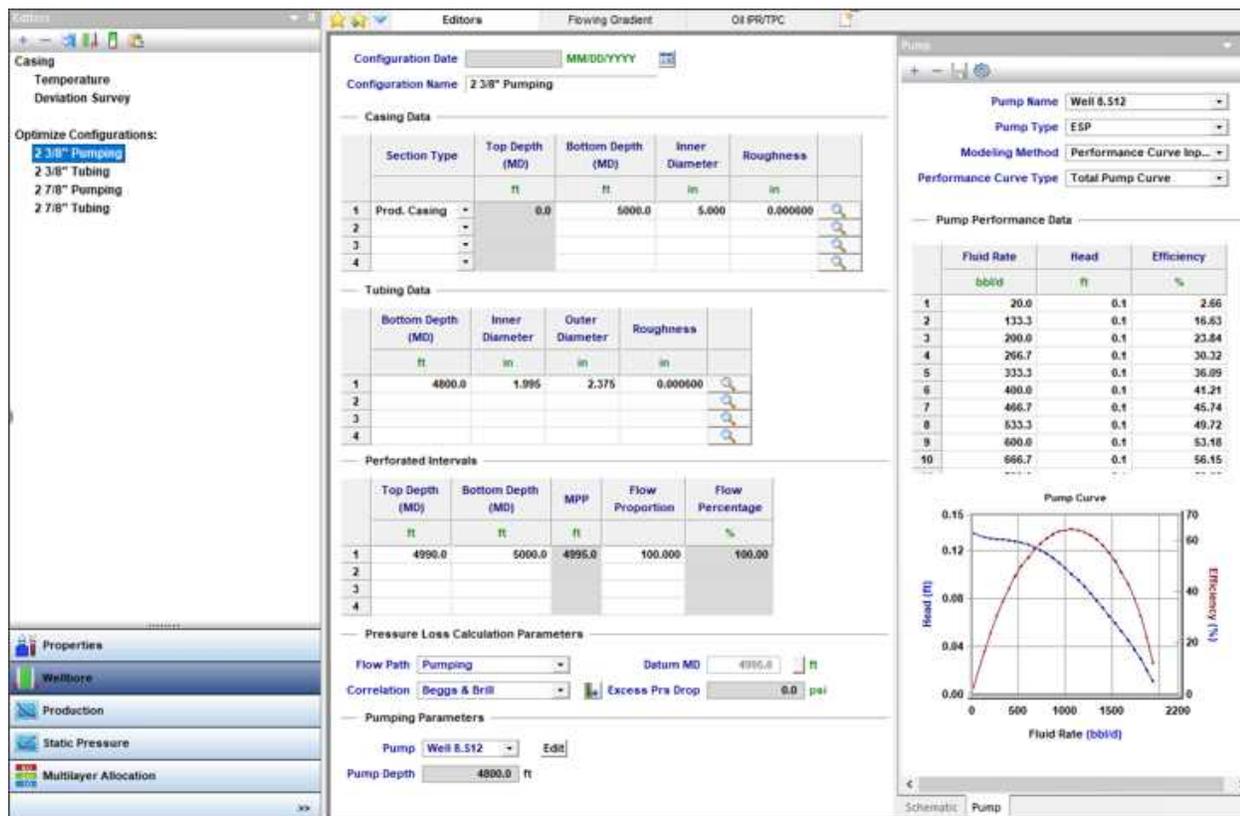
Schematic pane

By default, the wellbore Schematic pane opens to the right of the configuration parameters. This schematic is a two-dimensional visual representation of the well information that has been provided. The depth scale appears to the left of the wellbore. The flow path of the produced fluid in the well is displayed in green, and injected fluid is displayed in red. Perforations are indicated in red, and the datum is depicted with a dashed blue line.



Pump pane

With your Harmony Optimize license, you have access to ESPs for Optimize Configurations. Pumps can be viewed, created, and edited by clicking the Pump tab at the bottom of the Schematic pane.



Individual pump specifications can be created in this pane.

To create a new pump:

1. Click the **Add New Pump** icon (+)
2. In the Pump Name field, type a name for your pump, or select from the drop-down list.
3. In the Performance Curve Type drop-down list, select either **Single Stage Curve** or **Total Pump Curve**.
4. If you selected Single Stage Curve, in the Number of Stages field, type your number of stages.
5. In the Pump Performance Data table, type or paste your pump specifications.
The Pump Curve plot is automatically updated as the table is populated.

Multilayer wells: Wellbore editor differences

The Wellbore editor is available to the well entity of a multilayered well, but it is not available to layer entities.

Layout changes for multilayer wells:

- Only one perforated interval is available per layer. The layer datum is the depth at which the flowing pressures for that interval (that is, for that layer) are calculated.
- The Well MPP field is the overall datum. This is the depth at which the flowing pressures for that well entity are calculated.

Configuration Date YYYY-MM-DD

Configuration Name

Casing Data

	Section Type	Top Depth (MD)	Bottom Depth (MD)	Inner Diameter	Roughness	
		ft	ft	in	in	
1	▼					
2	▼					
3	▼					
4	▼					

Tubing Data

	Bottom Depth (MD)	Inner Diameter	Outer Diameter	Roughness	
	ft	in	in	in	
1					
2					
3					
4					

Perforated Intervals

	Layer Name	Top Depth (MD)	Bottom Depth (MD)	Datum
		ft	ft	ft
1	Layer 01			
2	Layer 02			

Pressure Loss Calculation Parameters

Flow Path

Well MPP ft

Production editor

In the Production editor (located within the Editors pane), you can manipulate imported production and flowing pressure data, and create new production records. To open the Production editor, click **Production** at the bottom of the pane.

The required inputs for calculating sandface pressure (including auto-calculated sandface pressure) are:

1. A complete wellbore (wellhead + sandface temperature, casing, tubing (if flow path != casing), datum).
2. Properties for the fluids being produced (gas, oil, water, and condensate).
3. An active pressure (set by Pressure Source; either casing, tubing, gauge depth, or imported sandface pressure).
4. Production for the fluids being produced (although sandface pressures are calculated without production / assumed to be shut-in)

The Production editor consists of the following parts:

- [Toolbars](#)
- [Selection tree](#)
- [Grid \(table\)](#)

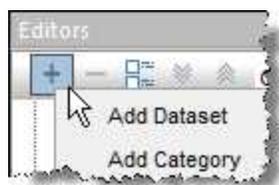
Toolbars

The Production editor has two toolbars: primary and secondary. The unique items are described below; for a description of common icons, see [toolbars](#).

Primary toolbar

The primary toolbar for the Production editor is located directly below the Editors pane.

Clicking the + icon on this toolbar lists two options.

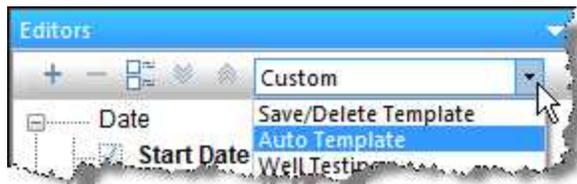


- **Add Dataset** — opens the [Create Custom Dataset dialog box](#). You can create two different types of custom datasets: input (using values you enter) and calculated (using equations you enter). The selection tree updates after you add your dataset and your update is viewable on the Plot Selection pane and Diagnostics tab.
- **Add Category** — opens the Create Custom Category dialog box where you can create custom categories to group your data. The selection tree updates after

you add your category and your update is viewable on the Plot Selection pane and Diagnostics tab.

You can click the – icon after selecting the custom dataset or category you want to delete. You are prompted to confirm your decision when deleting a custom dataset, but a custom category is immediately deleted.

After you have customized the table / grid display to your liking, you can save your configuration as a template for re-use. Click the drop-down arrow on the toolbar and select **Save / Delete Template**. To load a previously saved template, select it from the drop-down list.



If you select **Auto Template** (default setting), the following columns are displayed, if they have data:

- Gas Volume
- Oil Volume
- Water Volume
- Cond Volume
- CO2 Volume
- Gas Lift Inj Volume
- Gas Inj Volume
- Water Inj Volume
- Casing Pressure
- Tubing Pressure
- Line Pressure
- Gauge Depth Pressure
- Imported Sandface Pressure

The following Flowing Pressure columns are displayed, if at least one of these columns has data: casing pressure, tubing pressure, gauge depth pressure, or imported sandface pressure:

- Pressure Source
- Active Pressure
- Calculated Sandface Pressure

The following columns are displayed if any wellbore configuration has the Flow Path set to "Pumping":

- Gas Volume
- Casing Pressure
- Pressure Source
- Active Pressure
- Calculated Sandface Pressure
- Liquid Level (MD)
- Liquid Level (TVD)
- Average Liquid Gradient
- Gas Gradient
- Oil Gradient
- Water Gradient

Downhole gauge pressure data can be used to calculate the sandface pressure. This functionality is only available for Tubing, Pumping and Casing flow paths with the following assumption: gauge and tubing are landed above datum (MPP).

Note: For the pumping flow path the gauge cannot be above the end of tubing (EOT).

Secondary toolbar

This editor has the following important icons on its secondary toolbar (to the right of the Editors pane):

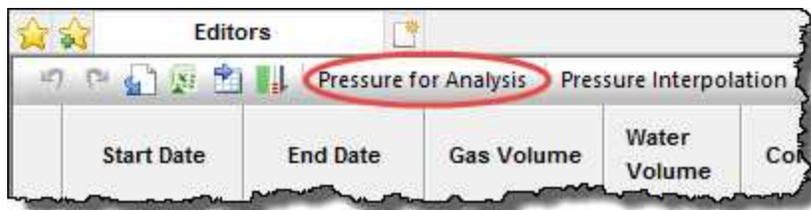
-  **Add Data** — adds data to the current well. Select either:
 - **Enter Data** — opens the Import Data dialog box where you assign column headers (by clicking the drop-down arrows) and type in your data.

- **Import Data** — browse to the undefined text file (for example, .csv, .txt, etc.) you want to import. For more information, see [import well data from a file](#).
-  **Prior Production** — loads prior production data into the table.
-  **Calculate Sandface Pressure** — calculates sandface pressure each time you click this icon.
- **Pressure for Analysis** — select either Use Active Pressure or Use Calculated Sandface Pressure. For more information, see [pressure for analysis](#).
- **Pressure Interpolation** — select either Linear (affects Custom CGR and Liquid Level MD columns) or Step (affects Pressure Source and CGR Source columns). Interpolated pressures are displayed in gray and populate rows that have not been specified. For more information, see [pressure interpolation](#).

Pressure for analysis

With this option, you can specify which flowing pressure is used in any analyses with calculations that require this value (for example, analytical models, etc).

The Pressure for Analysis option is located in the toolbar of the Production Editor grid.



When selected, there are two options to choose from:

1. **Use Active Pressure** — uses the pressure that has been set under the Pressure Source column of the grid (that is, casing, tubing, gauge depth, or imported sandface pressure) as the flowing pressure in analyses.



Note: If active pressure has been set to a wellhead pressure (for example, tubing pressure), and "Use Active Pressure" has been selected, all analyses will use the tubing pressure as the flowing pressure in calculations. This could result in significant differences in results compared to using a calculated sandface flowing pressure. If imported sandface pressures are not available, we recommend calculating a sandface pressure and setting the pressure for analysis to "Use Calculated Sandface Pressure".

2. Use Calculated Sandface Pressure — uses the calculated sandface pressure in the Production editor for flowing pressure in analyses. This is the default selection.

Start Date		End Date	MMscf	psi(a)	Gauge Depth Pressure	Active Pressure	Pressure Source	Calculated Sandface Pressure
YYYY-MM-DD	YYYY-MM-DD	YYYY-MM-DD						psi(a)
1	1997-10-13	1997-10-14	2.016	354.69	605.49	605.49	Gauge Depth Pressure	605.49
2	1997-10-14	1997-10-15	2.603	352.90	699.11	699.11	Gauge Depth Pressure	699.11

Note: A valid wellbore is needed to calculate sandface pressures.

The pressure used in analyses is highlighted in turquoise.

Pressure interpolation

Flowing-pressure columns automatically populate empty cells with data, whenever possible. The values are interpolated based on whether you select Linear or Step:

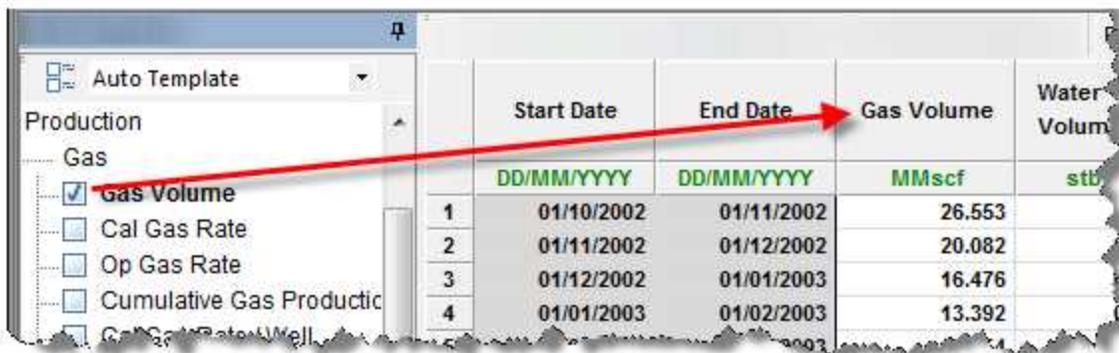
- For both the linear and step methods, all rows prior to the first-specified value are set to the first-specified value. All rows after a specified value are set to the last-specified value.
- For the step method, all rows after a specified value are set to the specified value until the next specified value.
- Cells in gray have been calculated or interpolated.
- For the linear method, all rows between two specified values are linearly interpolated. Linear interpolation is calculated at the mid-period for each row. The table below demonstrates this interpolation.

Start Date	End Date	Value	Mid-period Date
2010/01/01	2010/02/01	100.00	2010/01/16 12:00:00
2010/02/01	2010/03/01	132.96	2010/02/15 00:00:00
2010/03/01	2010/04/01	165.92	2010/03/16 12:00:00
2010/04/01	2010/05/01	200.00	2010/04/16 00:00:00

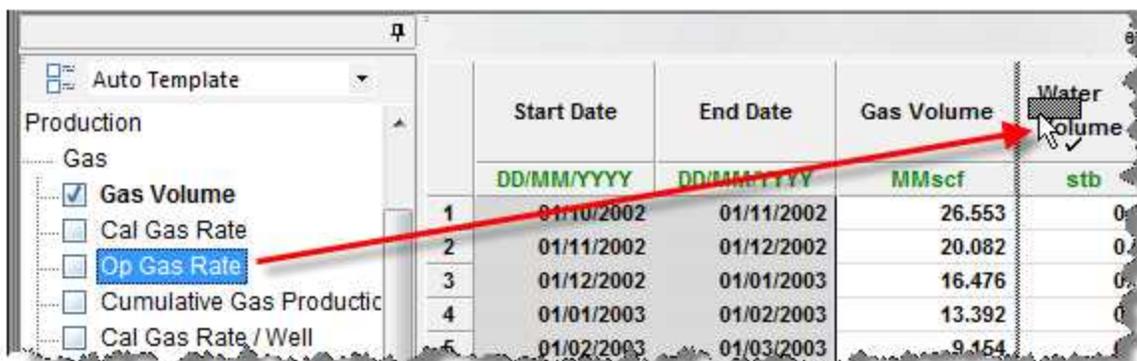
For more information, see [interpolation theory](#).

Selection tree

The selection tree has production / injection, flowing pressure, and other data reported by date / time. To display data in the table to the right, click your dataset's checkbox in the tree structure. Deselecting a dataset's checkbox removes it from the table.



You can also add data to the table by clicking the dataset name and dragging it to its desired location



If you want to rename a custom dataset or category, right-click it in the selection tree and select Rename. (You can add these custom datasets and categories using the [primary toolbar](#).)

Grid (table)

The grid (or table), located on the right-side of the Production editor, displays the selected entity's production data. The Start Date and End Data columns are always displayed as the left-most columns in the grid, and cannot be moved or removed. All of the other columns can be

shown / hidden by selecting / deselecting the parameter's name in the selection tree, or by moving the parameter within the grid.

	Start Date	End Date	Gas Volume	Op Gas Rate
	YYYY/MM/DD	YYYY/MM/DD	MMscf	
1	2000/09/09	2000/09/10	0.000	0.000
2	2000/09/10	2000/09/11	0.550	0.550
3	2000/09/11	2000/09/12	0.550	0.550
4	2000/09/12	2000/09/13	0.550	0.550

To change the units, click the unit sub-header and select from the list. You can also set precision.

	Start Date	End Date	Op Gas Rate	Gas Volume
	YYYY/MM/DD	YYYY/MM/DD	MMscfd	
1	2000/09/09	2000/09/10	0.000	
2	2000/09/10	2000/09/11	0.550	
3	2000/09/11	2000/09/12	0.550	
4	2000/09/12	2000/09/13	0.550	
5	2000/09/13	2000/09/14	0.550	
6	2000/09/14	2000/09/15	0.550	
7	2000/09/15	2000/09/16	0.550	
8	2000/09/16	2000/09/17	0.550	
9	2000/09/17	2000/09/18	0.550	
10	2000/09/18	2000/09/19	0.550	
11	2000/09/19	2000/09/20	0.200	
12	2000/09/20	2000/09/21	0.300	
13	2000/09/21	2000/09/22	0.550	
14	2000/09/22	2000/09/23	0.550	
15	2000/09/23	2000/09/24	0.550	
16	2000/09/24	2000/09/25	0.400	

Fields with a white background can be edited by typing within the field, or pasting from another source (for example, Excel).

Note: If you select multiple wells, or a well group in the Entity Viewer, you cannot edit any of the fields. Gray fields (including cumulative production, ratios, and aggregates) are read-only.

To remove a row from the grid, right-click the row number and select Remove Row. You can only remove rows at the end of production.

Multilayer wells: Production editor differences

The Production editor for a layer entity is read-only, and the production data is calculated from the well entity's production data and the allocation factors from the Multilayer Allocation editor.

In the Production editor for a multilayer well, Pressure Source can be set to: Casing Pressure, Tubing Pressure, or Gauge Depth Pressure. Imported Sandface pressure is not supported for multilayer wells.

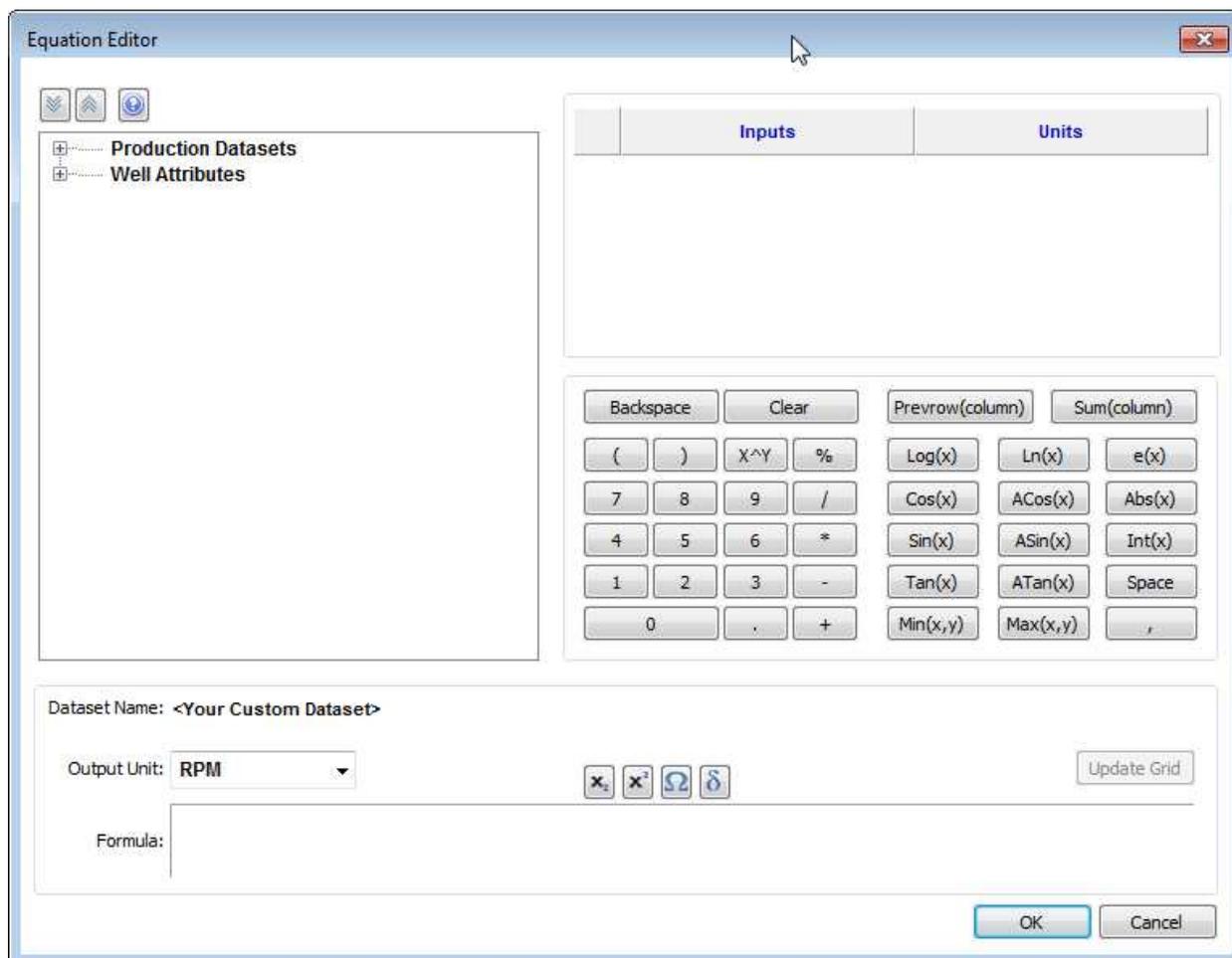
Create Custom Dataset dialog box

This dialog box is commonly used when you add custom datasets.

- **Dataset Name** — type your dataset name. This is a required field and you cannot click OK until this field has been entered. "Invalid Dataset Name" is displayed until you type a name.
- **Unit Type** — select from the drop-down list. Note that this field cannot be edited after it is set.
- **Default Field Unit** — select your default field unit from the drop-down list.
- **Default Metric Unit** — select your default metric unit from the drop-down list.
- **Location** — select the dataset's location in the Production Editor's tree structure from the drop-down list.
- **Input** — uses values you enter.
- **Calculated** — opens the Equation Editor dialog box where you enter formulas for this dataset.

Equation Editor dialog box

This dialog box is commonly used when you add custom datasets or add custom attributes, and you want to use a Calculated type of dataset or attribute.



The Equation Editor has the following components:

- **Tree structure** — displays an updated list of all the production datasets that exist in the Production editor, as well as the numerical attributes that exist in the Attributes tab. This includes custom-calculated datasets, custom-input datasets, custom-input attributes, and custom-calculated attributes. Clicking an item in the tree structure inserts it into the formula.
- **Inputs / Units pane** — displays the units associated with each input.
 - If a dataset or attribute is displayed in an equation twice, only one unit can be associated with that variable.

- The table / grid displays a list of datasets / attributes in the formula pane when you click the **Update Grid** button, *after* you enter a valid formula. You can also update the table / grid each time you make a modification to the formula by clicking the **Update Grid** button.
- Note that if your formula is invalid, clicking **OK** or **Update Grid** displays an error message in the lower left corner of the dialog box.
- **Calculator** — consists of numbers and mathematical functions.
- **Formula pane** — displays the formula as you create it.
 - The *output unit* is the unit associated with the output of your formula.
 - By clicking the four icons directly above the formula area, you can insert subscript, superscript, and symbols within the formula.
 - You can use both the on-screen calculator (by clicking the buttons in the dialog box) and your keyboard.

Tip: When entering a formula, make sure to add the closing “)” when using a function that opens with a “(“. If your formula is invalid, clicking **OK** displays an error message in the lower left corner of the dialog box.

Referencing other datasets / attributes

You can enter a formula into the Formula pane using the keyboard. To reference another dataset or attribute, you must use the following format:

- Attribute: [A:Attribute Name]
- Dataset: [P:Dataset Name]

Dataset-specific functions

There are four special functions: *MinCol*, *MaxCol*, *Avg*, and *ValueAt*. These functions require production datasets (in columns) as inputs, and normalized time must also be specified.

- The units of normalized time can be selected in the Inputs / Units pane in this dialog box.
- The values "start" and "end" can also be entered as normalized time values. "Start" refers to the beginning of production history, and "end" references the last date of production.

Note: Normalized time must be specified as an integer.

1. **MinCol** — this function returns the smallest value of the specified column, over a specified period of normalized time.

Equation Format: MinCol(column, start time, end time)

Example: MinCol([P:Gas Volume], end-6, end)

This returns the minimum gas volume during the last six months of production.

2. **MaxCol** — this function returns the highest value of the specified column, over a specified period of normalized time.

Equation Format: MaxCol(column, start time, end time)

Example: MaxCol([P:Gas Volume], start, end)

This returns the maximum gas volume during the entire production history of the well.

3. **Avg** — this function returns the weighted average of the specified column, over a specified period of normalized time.

Equation Format: Avg(column, start time, end time)

Example: Avg([P:Gas Volume], 3, 12)

This returns the average gas volume between the 3rd and 12th months of production, based on the following equation:

$$average(x, t) = \frac{\Sigma(x * \Delta t)}{\Sigma \Delta t}$$

Although you can specify the period in months, Harmony Enterprise inputs the Δt in days when calculating the weighted average. So, based on the month in the year, Δt can be 28 - 31 days for a full month.

4. **ValueAt** — this function returns a scalar value from the specified column, at a specified normalized time.

Equation Format: ValueAt(column, time).

Example: ValueAt([P:Gas Volume], 1.5)

This returns the gas volume at 1.5 months. Calculations are done using days, and monthly values are converted using 365.25/12. So, in this case, 1.5 months would be equivalent to 45.6 days. Harmony returns the value at the row that covers the time range which includes this specific time.

Note: The start time in Harmony Enterprise is inclusive, and the end time is exclusive.

Pressure calculations

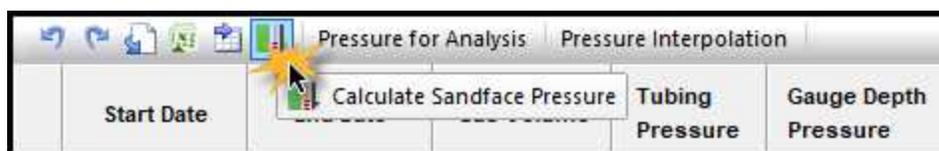
The Production editor can be used to perform pressure calculations along a wellbore. Another term for this is sandface pressure calculations, since the wellbore is used to calculate the pressure at the sandface from some reference pressure (for example, wellhead pressure or a gauge pressure). There are three main types of calculations that can be performed:

1. Production calculations
2. Injection calculations
3. Static calculations

For detailed information on pressure calculations, see [calculations and correlations](#).

Triggering pressure calculations

To trigger pressure calculations manually, click the **Calculate Sandface Pressure** icon in the toolbar.



You can also calculate pressure automatically by importing production data (see [get well data into Harmony Enterprise](#)). For more information, see [autocalc settings](#).

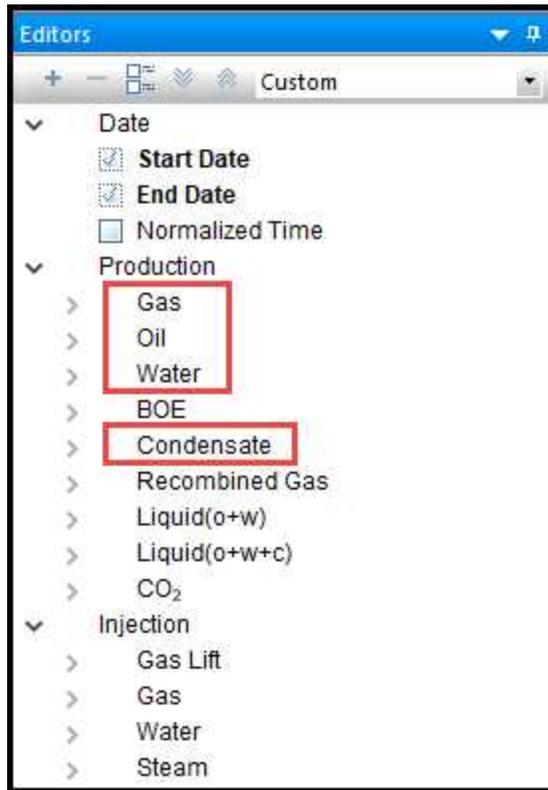
Starting pressure

All calculations use Active Pressure as the starting value. The active pressure is defined by your Pressure Source selection.

Pressure Source	Active Pressure
	psi(a)
Gauge Depth Pressure	605.49
	699.11
Casing Pressure	1057.31
Imported Sandface Pressure	658.58
Tubing Pressure	805.39
Gauge Depth Pressure	675.49
Gauge Depth Pressure	596.86

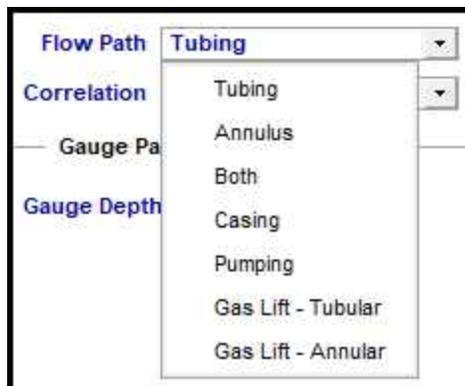
Production calculations

Production is defined as flow from the sandface (or reservoir) to the wellhead (surface). Consequently, if any of the gas, oil, condensate, or water production rates are positive, then the Production editor takes into account that the wellbore is producing.



Supported wellbore flow paths

All of the wellbore flow paths are supported for pressure calculations in the Production editor.

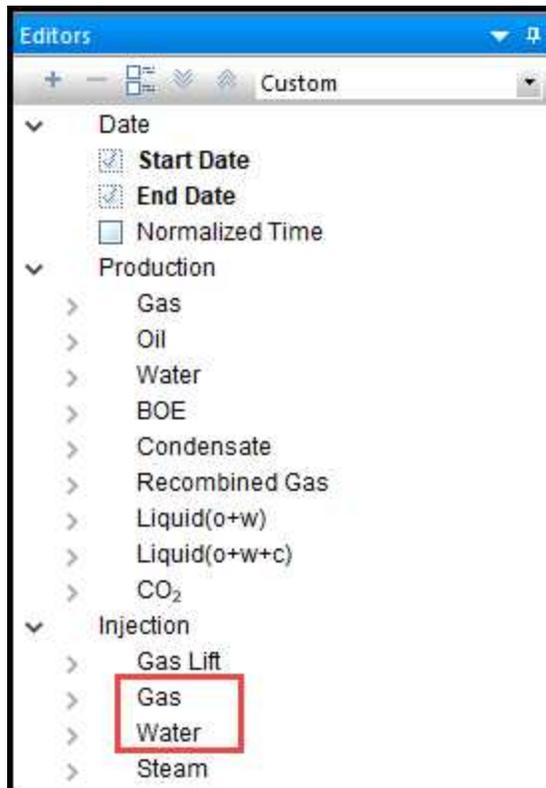


Injection calculations

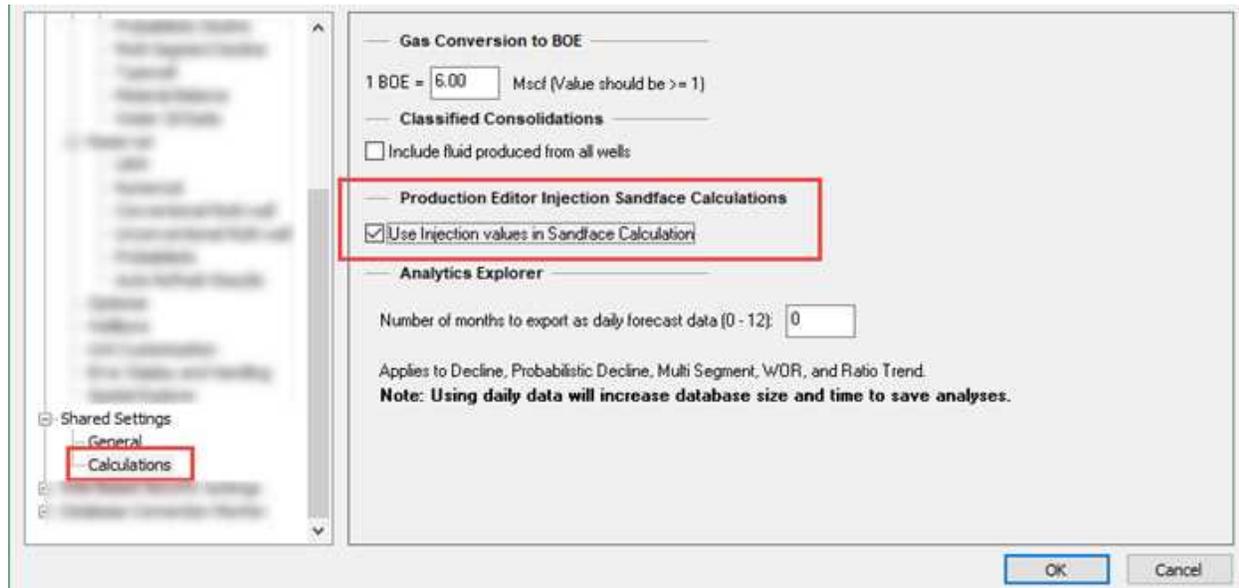
Injection is defined as flow from the wellhead (surface) to the sandface (reservoir).

For the Production editor to account for injection:

- The production gas, oil, condensate, and water rates must all be zero (or blank).
- The injection gas or water rates must be positive.

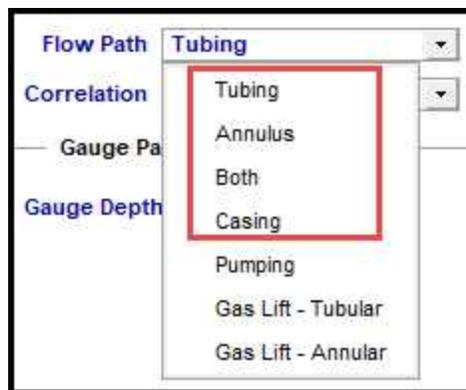


In addition, in the Options dialog box, the **Use Injection values in Sandface Calculations** checkbox must be selected.



Supported wellbore flow paths

For injection, only these flow paths are supported for pressure calculations in the Production editor: tubing, annulus, both, and casing.



Note: Quiet-side calculations are not supported.

Static calculations

A static (or shut-in) wellbore is defined when no flow exists in the wellbore.

For the Production editor to take into account that the well is static:

- The production gas, oil, condensate, and water rates must all be zero (or blank).

- The injection gas or water rates must all be zero (or blank).

And if a gas-lift flow path is selected, then the gas lift rate must be zero (or blank).

Supported wellbore flow paths

All of the wellbore flow paths are supported for static calculations in the Production editor.

- For the pumping flow path, the liquid level and gradient(s) are used to calculate the sandface pressure.
- For other flow paths, the wellbore is assumed to be filled with gas.

Note: Static calculations in the Production editor are different from calculations in the Static Pressure editor.

Static Pressure editor

In the Static Pressure editor (located within the Editors pane), you can view, enter, and modify static pressures for wells. Static pressures can also be viewed at the group level, but not manipulated. In addition, you can view static pressures for scenarios.

The Editors pane on the left-side has a list of data series that you can select to be displayed in the table. By default, all of the series are selected to be displayed. In addition, the following columns are always displayed (that is, they cannot be hidden): test date, static gauge depth pressure, gauge depth, use in analysis, static sandface pressure, and static pressure at datum).

The screenshot shows the 'Editors' pane with a 'Data Series Selection' list on the left and a 'Pressure Data Table' on the right. The table includes columns for Test Date, Static Gauge Depth Pressure, Gauge Depth (TVD), Use in Analysis, Static Sandface Pressure, Static Pressure at Datum Depth, Effective Gradient, RD - Datum Offset, and Shut-in Time. A 'Toolbox' at the top right of the table area lists well parameters: Top Perf (TVD) 3972.1 ft(KB), Bottom Perf (TVD) 3988.5 ft(KB), Sandface Depth (TVD) 3980.3 ft(KB), KB Elevation 2546.6 ft(MSL), and Datum (msl) -1433.7 ft(MSL).

Test Date	Static Gauge Depth Pressure	Gauge Depth (TVD)	Use in Analysis	Static Sandface Pressure	Static Pressure at Datum Depth	Effective Gradient	RD - Datum Offset	Shut-in Time
MM/DD/YYYY	psi(a)	ft(KB)		psi(a)	psi(a)	psi/ft	ft	h
1	10/17/1981	1548.13	<input checked="" type="checkbox"/>	1548.13	1548.13		0.000	
2	10/28/1981	1547.84	<input checked="" type="checkbox"/>	1549.20	1549.20	0.129	10.499	0.000
3	11/05/1981	1543.64	<input checked="" type="checkbox"/>	1546.56	1546.56	0.055	53.150	133.000
4	06/13/1986	1451.10	<input checked="" type="checkbox"/>	1453.63	1453.63	0.049	51.509	118.600
5	06/13/1986	1454.29	<input checked="" type="checkbox"/>	1454.94	1454.94	0.049	13.123	120.200
6	06/13/1986	1455.16	<input checked="" type="checkbox"/>	1455.16	1455.16		0.000	
7	06/12/1988	1325.64	<input checked="" type="checkbox"/>	1326.46	1326.46	0.043	19.029	168.000
8	06/14/1989	1261.68	<input checked="" type="checkbox"/>	1262.31	1262.31	0.048	13.123	155.000
9	06/14/1989	1261.39	<input checked="" type="checkbox"/>	1261.39	1261.39		0.000	
10	09/19/1992	1037.02	<input checked="" type="checkbox"/>	1038.62	1038.62	0.122	13.123	349.300
11	09/19/1992	1037.02	<input checked="" type="checkbox"/>	1038.62	1038.62	0.122	13.123	349.300
12	09/07/1996	623.37	<input checked="" type="checkbox"/>	623.69	623.69	0.024	13.123	102.000
13	05/06/1999	475.58	<input checked="" type="checkbox"/>	474.78	474.78	0.015	-54.790	135.700
14	05/06/1999	453.82	<input checked="" type="checkbox"/>	455.38	455.38	0.014	111.549	133.200
15	05/06/1999	463.54	<input checked="" type="checkbox"/>	463.54	463.54		0.000	

Depths

The perforation intervals, sandface depth, kelly bushing (KB) elevation, and datum for the entity are displayed above the pressure data table. Some import file types (such as *.mer) include this well data. When it is not imported, the data that is specified in the Wellbore editor is used to populate these values. For wells, the sandface depth midpoint of perforation (MPP) is assumed to be the same as the datum depth. When a group is viewed, a common datum is determined for the group based on the datum of each well. No sandface depth is displayed for a group, as it is not meaningful.

Header

These items are displayed above the table in the main pane:

- **Top Perf (TVD)** — the uppermost perforation depth from the Attributes tab or the Wellbore editor. (The Wellbore editor's perforation interval inputs override the Attributes tab's inputs.) The top perf depth is converted from measured depth (MD) to true vertical depth (TVD) based on the Deviation Survey entered in the Wellbore editor.
- **Bottom Perf (TVD)** — the lowermost perforation depth. The bottom perf depth is converted from MD to true vertical depth TVD based on the Deviation Survey entered in the Wellbore editor.
- **Sandface Depth (TVD)** — the midpoint of the perforated interval (MPP). You cannot change the Sandface Depth in the Static Pressure editor by changing the Datum Depth in the Wellbore editor. It is calculated based on top and bottom perf inputs (from the Attributes tab or Wellbore editors) only. You cannot type a fixed reservoir datum depth.
- **KB Elevation** — the kelly bushing (KB) reference elevation. All datum calculations reference the KB elevation.
- **Datum (msl)** — the true vertical depth relative to mean sea level (msl). This value changes depending upon the launched entity as described below:
 - For Well entities: "Datum" depth is always the Sandface or MPP depth in TVD for the well. This is *not* the Datum Depth referred to in the Wellbore editor.
 - For Group entities: "Datum" depth is calculated from the average well Datum Depths of the wells in the group. As group membership changes, the group datum depth changes. The intention is to automatically minimize the Datum Depth correction required for each well in the group. You cannot type a fixed reservoir datum depth.

Pressure data table

The minimum requirements for an entry in the pressure table are a date and a static gauge depth pressure. Additional information that can be provided includes the gauge depth, shut-in time, static wellhead pressure, gauge pressure gradient, gauge depth temperature, comment, and test info.

In the Use in Analysis column, you can select which static pressures are displayed on worksheets and which are used in the analysis. By default, all static pressures are selected.

When a gauge depth is not provided, the gauge depth is assumed to be the same as the datum. When a gauge depth is available, the gauge depth pressure gradient is used to convert the static pressure at the gauge depth to a datum pressure. The same approach is used to convert static pressures from a well datum to a group datum. When the gauge depth pressure gradient is not provided (or if the input value is 0), fluid properties from the Properties editor are used to estimate a pressure gradient.

Column headers

Column headers are defined as follows:

- **Static Gauge Depth Pressure** — the gauge measured pressure in absolute pressure units.
- **Gauge Depth** — the depth of the gauge used to measure the static pressure.
- **Static Sandface Pressure** — the Gauge Depth Pressure corrected to the Sandface Depth or MPP of a launched well entity.
- **Static Pressure at Datum Depth** — the Gauge Depth Pressure corrected to the Datum Depth for a launched group entity. You cannot type a fixed reservoir datum depth. The Static Pressure at Datum Depth for a well entity, or a group with only one well, is always the same as the Static Sandface Pressure. The Static Pressure at Datum Depth and the Static Sandface Pressure are only different when there are multiple wells in the group with differing MPPs based on datum depths.
- **Effective Gradient** is either:
 - (a) the “Gauge Pressure Gradient” you entered, or
 - (b) An internally calculated gradient based on the specified Primary Fluid in the Attributes tab, the input Gauge Depth Pressure, the reservoir temperature in the Properties editor, as well as inputs in the Wellbore and Fluid Properties editors.

- We use (a) when the Gauge Gradient contains a non-zero value
 - We use (b) when the Gauge Gradient contains a zero, or is blank.
- **Static Wellhead Pressure**— you can type a value for information purposes. In rare circumstances, we have only measured well static pressure data and no gauge measured data. In those cases, you can copy / paste the Static Wellhead Pressures over to the Gauge Depth Pressure column. If you specify a Gauge Depth of "0" (zero) and set the Primary fluid to gas, oil, or water, Harmony Enterprise calculates Sandface and Group Datum pressures based on sandface depth (MPP) and the Effective Gradient. This method can be used for gas, oil, or water, but generally should only be used for gas. It also assumes there are no wellbore or reservoir fluid contacts between the wellhead and the calculated datum depth.
 - **Gauge Pressure Gradient** — the pressure gradient measured at or near the gauge depth in the wellbore. You should be careful when using imported values, as these gradients generally reflect wellbore fluid contacts, and not necessarily the fluid contacts in the reservoir.

Note: The remainder of the column headers are provided for information only, and are not used in the calculations.

Multilayer wells: Static Pressure editor differences

The Static Pressure editor is available to the well entity of a multilayered well, but it is not available to layer entities.

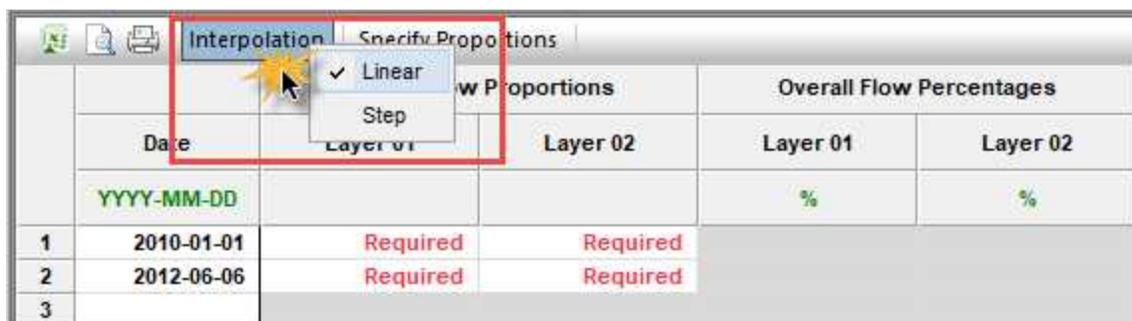
Multilayer Allocation editor

With the Multilayer Allocation editor (located within the Editors pane), you can assign flow proportions for each layer in a multilayered well. Using these flow proportions, rates for each layer can be calculated from the overall well rates in the Production editor. (Typing values in this editor must be done at the well level.)

Since flow proportions are allocated on a time basis, the first step is to specify at least one calendar date. If only one date exists, then the flow proportions apply to every date in the Production editor. However, if the proportions are changing over time, then multiple dates can be typed into the Multilayer Allocation editor.

Interpolation

Interpolation is used to determine the allocation between the specified dates in the Multilayer Allocation editor. There are two interpolation options: linear and step.

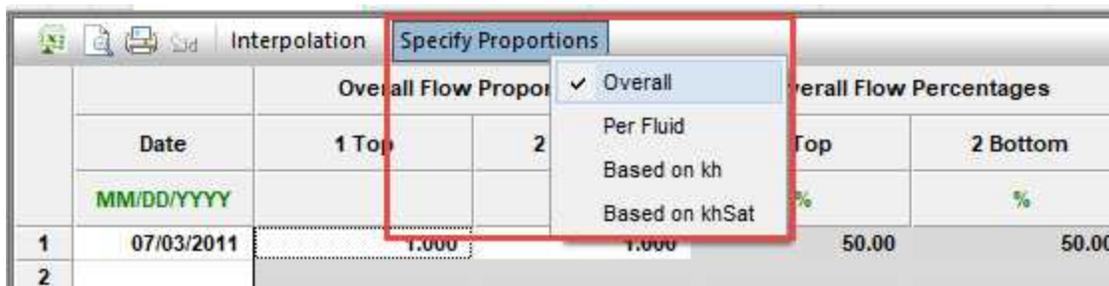


1. Linear interpolation calculates an average change in flow proportions from one date to the next. This is the default setting.
2. Step interpolation keeps the proportions static until the next date is reached. When that next date is reached, the proportions instantly change.

Regardless of the specified interpolation method, any entries in the Production editor that occur before the first date in the Multilayer Allocation editor use the allocation percentages in the first row. Likewise, any production data after the last-specified allocation date continues to use that allocation.

Specifying proportions – overall

The simplest way to allocate is to specify the overall flow proportions. This method applies the same allocation to all fluids equally. The only thing that can be set is the percentage of the total fluid that comes from each layer. Percentages are set indirectly by typing values into the flow proportion fields. For example, in a two-layer well, if each layer is specified with a proportion of “1”, then 50% of the total fluid is allocated to each layer.



Specifying proportions – per fluid

By specifying proportions on a per-fluid basis, you can have greater control over allocations. For example, if you are producing only gas from one layer, and only water from another layer, then a per-fluid allocation is necessary.

Date	Gas Flow Proportions		Gas Flow Percentages		Water Flow Proportions		Water Flow Percentages	
	1 Top	2 Bottom	1 Top	2 Bottom	1 Top	2 Bottom	1 Top	2 Bottom
MM/DD/YYYY			%	%			%	%
1 07/03/2011	0.000	1.000	0.00	100.00	1.000	0.000	100.00	0.00
2								

By selecting **Per Fluid** from the toolbar, fluid proportion fields become editable (and any overall proportions are ignored).

Specifying proportions – based on kh

If you know permeability (k) and net pay (h) for each layer, you can allocate layer production based on kh. Type your known layer permeabilities, then type net pay, or click the **Pull Defaults** icon () for layer properties to bring net pay from your layer's Properties editor.

Date	Permeability		Net Pay		Overall Flow Percentages	
	1 Top	2 Bottom	Top	2 Bottom	1 Top	2 Bottom
MM/DD/YYYY	md		ft	ft	%	%
1 07/03/2011	Required	Required	200.0	120.0		
2						

Specifying proportions – based on khSat

If you know permeability (k), net pay (h) and fluid saturations for each layer, you can allocate layer production based on khSat. Type your known layer permeabilities, then type net pay and fluid saturations. Or, you can click the **Pull Defaults** icon () for layer properties to bring net pay and fluid saturations from your layer's Properties editor, and you need to specify saturation for each of the phases that are present in the Production editor.

Date	Permeability		Net Pay		Gas Saturation		Water Saturation	
	1 Top	2 Bottom	Top	2 Bottom	1 Top	2 Bottom	1 Top	2 Bottom
MM/DD/YYYY	md		ft	ft	%	%	%	%
1 07/03/2011	Required	Required	200.0	120.0	80.00	70.00	20.00	30.00
2								

Special Considerations

There are special considerations for condensate and time on production / injection.

Condensate

Whenever pressure calculations are performed with condensate (Constant Rv), extra attention should be paid to the Multilayer Allocation editor. Since both gas and condensate rates can be allocated differently, the condensate-gas ratio can be quite different from one layer to the next.

In the Production editor for the well, there are two ways to control the CGR Source. When “CGR” is selected, it uses the allocated condensate volume and gas volume to calculate a CGR for each row. However, if “CGRcustom” is selected, then the per layer CGRcustom is calculated as follows:

$$\{CGR_{custom\ for\ the\ layer}\} = \frac{CGR_{custom\ for\ the\ well}}{GasFlowPercentage} \times CondensateFlowPercentage$$

Time on Production / Injection

Whenever a layer has none of the proportions allocated to it for a given row, it has zero allocation for the time on production (or injection). Otherwise, 100% of the time on production (or injection) is allocated.

Entity Viewer - Custom

The Entity Viewer - Custom displays private groups and shared groups. You can create custom groups from your list of wells in the hierarchy based on locations and groupings that are not possible within the hierarchy structure.

Note: Property correlations and the gas type are initialized for a group based on the values you have specified for its constituent wells. If these settings are not identical for all the wells in the group, Harmony Enterprise uses the default values.



If you import custom groups, they are shared, and each custom group is guaranteed a unique name. Note that custom groups are not imported when their ID already exists.

Clicking an entity in this pane highlights the entity in the [GIS map](#) and displays the entity's data under the other tabbed headings. (Only well and meter station entities are shown on the GIS map, and only if they have valid location information entered in their attributes.)

You can scroll through wells using your keyboard's arrow keys by doing the following: click the tab you want to view (for example, Analysis or Diagnostics), click a well in the Entity Viewer, and then press the Up and Down arrow keys on your keyboard.

You can select multiple entities by clicking wells while holding down the **Ctrl** key (to make individual selections), or the **Shift** key (to make bulk selections).

Toolbar

The Entity Viewer - Custom has the following important icons:

-  **Add Group** — create an empty custom group or create a group from entities you have selected.
-  **Remove Selected Entities** — select an entity or group in the tree structure and then click this icon to remove it. Note that if you delete an entity in a custom group, it is removed from the group, but it still exists in the project.
-  **Search** — opens a search box where you can search for entities by name. (You can also initiate a search by pressing **Ctrl + F**.)
-  **Query** — opens the [Query Wells dialog box](#) where you can query and filter wells using attribute data.

For a description of common icons, see [pane toolbars](#).

Note that if you selected a previously created filter (see [project filters](#)) prior to creating a new custom group, this custom group automatically exists in the filter.

Private groups tab

On this tab, you can view groups that only you can see.

These entities are user-specific and are not accessible by others unless you right-click a custom group and select **Share Group**. This moves the custom group to the Shared Groups tab.

Shared groups tab

On this tab, you can view groups and wells that are shared with users who have access to the database.

Work status icons

The Entity Viewer panes can use icons to indicate the work status of entities. You can set your work status manually by right-clicking the entity and selecting **Set Entity Work Status**. To reset your work status, right-click and select **Clear Status**.

The icons are as follows:

-  (**Complete**) — an analysis has been completed for this entity.
-  (**In Progress**) — this entity has been selected, and an analysis has been started, but it has not yet been completed.
-  (**Invalid**) — data for this entity has changed, and any analyses are no longer be valid.

Context menu

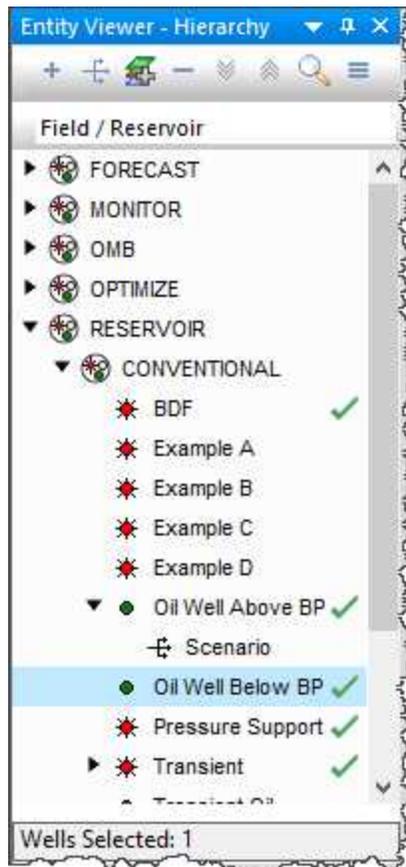
Right-clicking within this pane lists various options, which depend on the type of entity you select (for example, a well, group, or multiple wells).

- **Rename** — renames the entity.
- **Remove Selected Entities** — removes the selected entities from the custom group, but retains the entities in the database.
- **Rerun Well Query** — (visible after you have run a well query): if you have modified wells in your database, running the query again updates your results.
- **Select Constituent Wells** — (for groups): selects all of the wells that belong to the group. (This selection is applied to the Entity Viewer - Hierarchy as well.)
- **Set Entity Work Status** — changes the work status icon for the selected entity.
- **Apply Workflow to Selected Entities** — applies your workflow to the entities you selected. For more information, see apply a workflow.

- **Refresh Results for URM and FMB** — updates the FMB and URM results for the selected entities (wells, scenarios, or groups).
- **Refresh Results for Optimize** — updates the Gas IPR / TPC and Oil IPR / TPC results for the selected entities (wells, scenarios, or groups).
- **Refresh results for Declines** — updates the saved forecasts for decline analyses when the portion to be stored as daily is changed. For more information, see shared settings.
- **Move Selected into Custom Group** — moves the selected entities into a custom group.
- **Duplicate Selected into Custom Group** — copies the selected entities into the custom group you select from the submenu.

Entity Viewer - Hierarchy

The Entity Viewer - Hierarchy displays the entities in a project, which you can view, sort, and select for analysis. Note that there is a well count at the bottom, which counts wells and scenarios (but not groups).



Clicking an entity in this pane highlights the entity in the [GIS map](#) and displays the entity's data under the other tabbed headings. (Only well and meter station entities are shown on the GIS map, and only if they have valid location information entered in their attributes.)

You can scroll through wells using your keyboard's arrow keys by doing the following: click the tab you want to view (for example, Analysis or Diagnostics), click a well in the Entity Viewer, and then press the Up and Down arrow keys on your keyboard.

You can select multiple entities by clicking wells while holding down the **Ctrl** key (to make individual selections), or the **Shift** key (to make bulk selections).

Toolbar

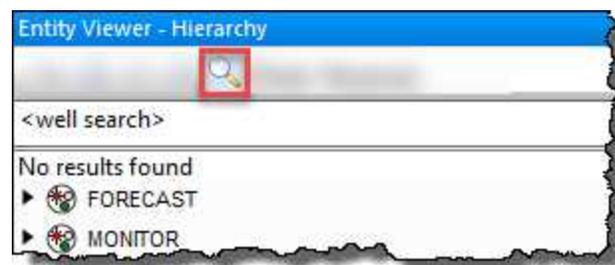
The Entity Viewer - Hierarchy has the following important icons:

- **+ Add Well** — opens a submenu where you can select your well type (for example, gas, oil, water, and so on).

-  **Add Scenario** — (for wells) adds a scenario child item below the parent well in the Entity Viewer - Hierarchy pane.
-  **Add Layer** — (for wells) adds a layer to the selected well.
-  **Remove Selected Entities** — select an entity / scenario in the hierarchy structure and then click this icon to remove it. This removes the entity from the database, so you are prompted to confirm your decision.

Any entities that you add or delete are reflected in the GIS, Diagnostics tab, analysis tab, Results tab, and Attributes tab. Deleting a well or group also removes it from the active filter.

-  **Search** — opens a search box where you can search for entities by name. (You can also initiate a search by pressing **Ctrl + F**.)



-  **Contextual Commands** — select from the Context menu options.
- **Hierarchy Structure** — you can add a hierarchy structure, modify an existing hierarchy structure, or select Field / Reservoir. If you select Add / Modify Hierarchy Structure, you can drag-and-drop fields from the Available Fields pane to the Current Hierarchy pane.

For a description of common icons, see [pane toolbars](#).

Work status icons

The Entity Viewer panes can use icons to indicate the work status of entities. You can set your work status manually by right-clicking the entity and selecting **Set Entity Work Status**. To reset your work status, right-click and select **Clear Status**.

The icons are as follows:

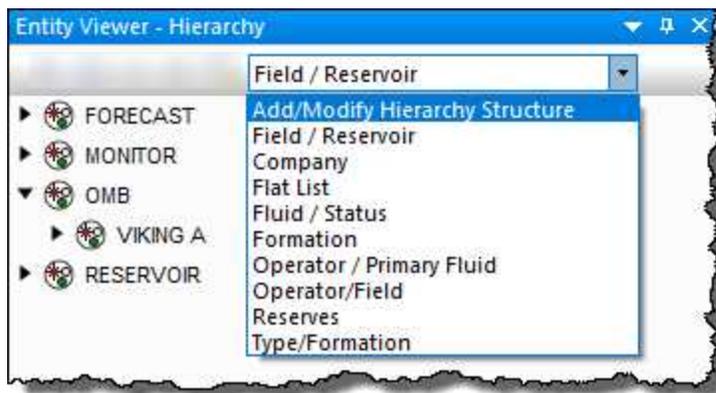
- ✓ **(Complete)** — an analysis has been completed for this entity.
- ! **(In Progress)** — this entity has been selected, and an analysis has been started, but it has not yet been completed.
- ? **(Invalid)** — data for this entity has changed, and any analyses are no longer be valid.

Hierarchy structure

The Hierarchy pane organizes entities in a hierarchical structure according to specific attributes, which you can view in the [Attributes tab](#).

To initially view wells, Harmony Enterprise provides a default hierarchy structure: Field / Reservoir. To create a new hierarchy structure, select **Add / Modify Hierarchy Structure** from the drop-down list.

After creating additional hierarchy structures, you can select it from the drop-down list on top of the pane.



Context menu

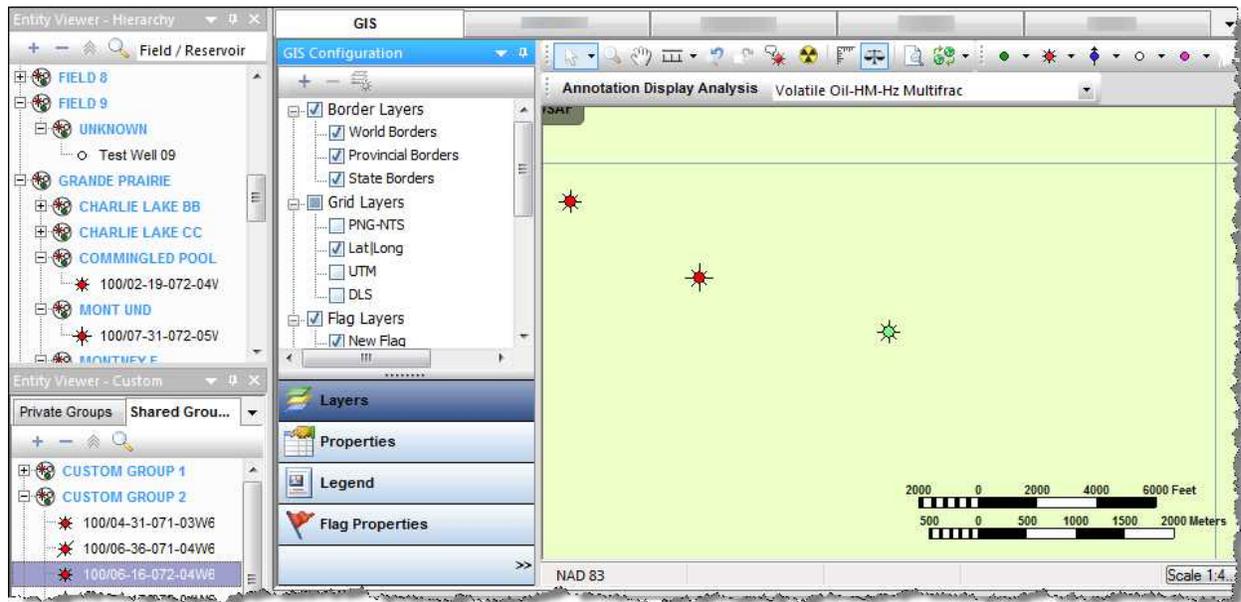
Right-clicking within this pane lists various options, which depend on the type of entity you select (for example, a well, group, or multiple wells).

- **Add Scenario** — adds a scenario child item below the parent well in the Entity Viewer - Hierarchy pane.
- **Duplicate Scenario** — (for scenarios) copies your currently selected scenario.

- **Promote to Well** — (for scenarios) replaces the parent well with the selected scenario, and demotes the parent well to a scenario. You are prompted to confirm your decision.
- **Rename** — opens a dialog box where you can type a new name for your entity (well or scenario).
- **Delete Selected Entities** — you are prompted to confirm the deletion, which removes the entities from the database. Note that you are not able to delete an entity that is locked by another user. To see the latest list of entities, click the **Refresh** icon () on the main toolbar.
- **Set Entity Work Status** — changes the work status icon for the selected entity.
- **Select Constituent Wells** — (for groups): selects all of the wells that belong to the group.
- **Expand Selected Group Only** — (for groups): expands the selected group.
- **Apply Workflow to Selected Entities** — applies your workflow to the entities you selected. For more information, see [apply a workflow](#).
- **Refresh Results for URM and FMB** — updates the FMB and URM results for the selected entities (wells, scenarios, or groups).
- **Refresh Results for Optimize** — updates the Gas IPR / TPC and Oil IPR / TPC results for the selected entities (wells, scenarios, or groups).
- **Refresh results for Declines** — updates the saved forecasts for decline analyses when the portion to be stored as daily is changed. For more information, see [shared settings](#).
- **Copy / Paste from Clipboard** — copies / pastes data from the Properties editor.
- **Go To** — after selecting an entity, you can right-click it and select Go To, which highlights the entity on the GIS map with a blinking circle. If location information is not available for the well, a warning message is displayed in the Status Window.

GIS

The geographic information system (GIS) tab displays entities on a map based on one of the standard coordinate systems.



Entities are displayed on the GIS map only if their attributes include geographical coordinates. If you expect to see well on the GIS map and it is not there, highlight it in the Entity Viewer - Hierarchy or Custom, click the **Attributes tab**, double-click **Location** in the tree structure, and verify that the latitude / longitude attributes are valid. For more information, see [GIS map](#).

Toolbars

There are four toolbars on the GIS tab:

1. GIS Configuration pane
2. GIS toolbar
3. GIS design mode tools
4. Active analysis

GIS Configuration pane

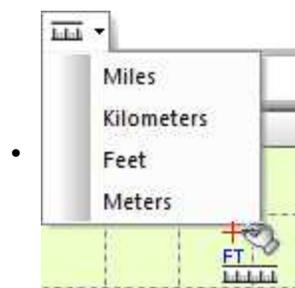
This toolbar handles layer functionality.



- **Add Layer** — adds various types of layers (that is, a shapefile layer, image layer, general annotation, bubble map layer, or a flag layer).
- **Remove Layer** — deletes a layer. Note that you cannot delete Project Layers.
- **Layer-specific options** — select from these options: group display layers by type, shapefile info, DBF info, customize shapefile drawing, highlight shape(s), and show / hide labels.

GIS toolbar

This toolbar handles map-related functionality. For a description of common icons, see [toolbars](#).



Measure — select your scale from the drop-down list.

Click the first location on the map and then drag the mouse to the second location. The distance is displayed between the two points, and updates automatically when the distance changes.

-  **Go back to Previous Extents** — reverts your display to the previous zoom setting.
-  **Go to Next Extents** — updates your display to the next zoom setting.

The current extents are saved on a per-user, per-project basis. When you open the project again, the last-used extents (zoom level) is applied.

-  **Annotation Display Options** — opens the [Facility Annotation Editor dialog box](#) where you can customize your annotation display. This icon is grayed-out when the annotation layer is not supported because there are too many wells on-screen.
-  **Reset GIS** — zooms out to display all the wells on the map, or if there are no wells, the map zooms out to display the entire world).

-  **Rulers** — displays a ruler along the top and left-side of the map. This can be toggled on or off.
-  **Scale** — displays a map scale in the lower right corner of the map. This can be toggled on or off.
-  **NAD Conversion** — from the drop-down list, select NAD 83 (North American Datum, modified in 1983), NAD 27 (North American Datum, created in 1927), or WGS 84 (World Geodetic System, modified in 1984).

Tip: To reset to the default mouse pointer, press the **Esc** key.

GIS design mode tools

Use this toolbar to draw wells on the map.



From left-to-right, the icons enable you to add an oil well (green), gas well (red), water well (blue), location (white), and other well (pink) to the GIS map.

Note: Icons on this toolbar are only active if you are zoomed-in close enough.

Active analysis

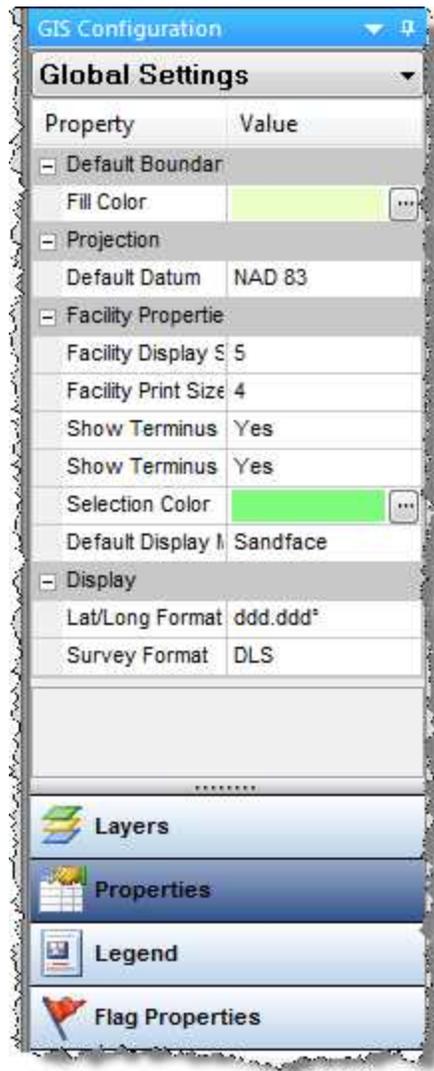
From this toolbar, you can select an analysis name from the drop-down list. The data from this analysis is used in Results annotations.



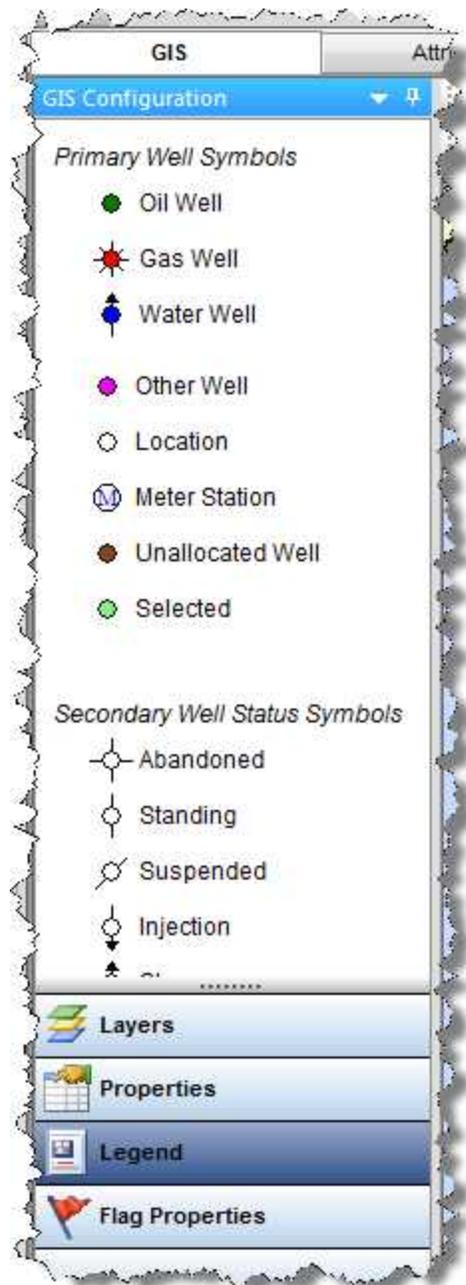
GIS Configuration pane

The GIS Configuration pane has the following buttons:

- Layers
- **Properties** — are used to fine-tune the GIS map. Property descriptions are displayed at the bottom of the pane as they are selected.



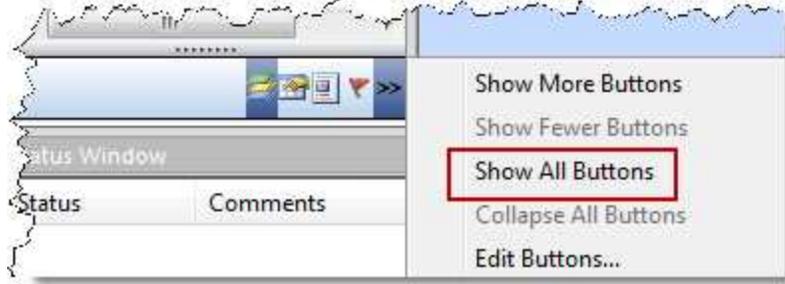
- **Legend** — lists all of the symbols that may be found on the GIS map.



Note: Meter stations are displayed on the GIS map only if they are included in an imported .dp2 or a 298 file.

- Flag Properties

If you do not see these buttons, click the angle brackets (>>) and select **Show All Buttons**.



Context menus

Right-clicking within the GIS Configuration pane lists various options, which depend on the type of layer you select (for example, border layers, grid layers, and so on):

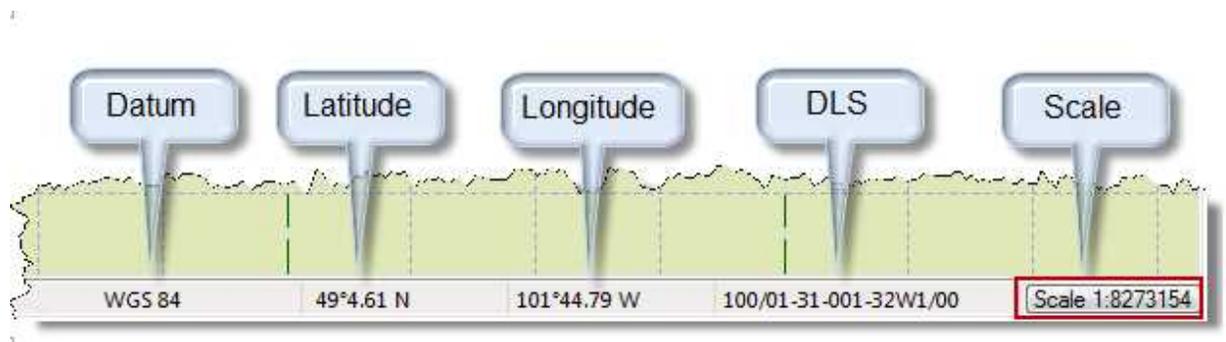
- **Select All Layers** — selects all of the layers for that layer type (for example, border layers).
- **Deselect All Layers** — deselects all of the layers for that layer type.
- **Group Display Layers By Type** — selecting this option groups layers by type; deselecting displays a flat list.
- **Add Shapefile Layer** — browse to your shapefile (.shp) file.
- **Shapefile Info** — opens the Shapefile Info dialog box where detailed information is provided (such as, the number and type of shape, label selection) along with a preview image.
- **DBF Info** — opens the DBF Info dialog box where attribute information is displayed. (The information in the DBF file is used when shapes are converted to facilities.)
- **Customize Shapefile Drawing** — opens the Customize Shapefile Drawing dialog box where you can change the line color, line thickness, fill color, and other visual attributes of the shape. You can also reset the settings to the default values.
- **Highlight Shapes** — highlights the selected shape.
- **Show Labels** — displays the label title for the shape.
- **Rename Shapefile Layer** — opens the Rename Layer dialog box where you can type in a new name for your shapefile.
- **Remove Shapefile Layer** — deletes the shapefile layer. Note that you are not prompted to confirm your decision.
- **Add Flag Layer** — adds a flag layer to the map.

- **Flag Properties** — opens the flag properties for that flag.
- **Remove Flag Layer** — deletes the flag layer.
- **Options** — opens the Bubble Map Editor dialog box where you can customize your bubble-map display.
- **Auto Range** — calculates a range based on the data for the entities used in the pie chart bubble map.
- **Legend** — select the item you want to display in the legend from the submenu (for example, color, size, section, and so on).
- **Rename** — opens the Rename Layer dialog box where you can type in a new name for your bubble-map layer.
- **Remove Bubble Map Layer** — deletes the bubble-map layer. Note that you are not prompted to confirm your decision.
- **Add General Annotation** — opens the General Annotation Editor dialog box where you can type your annotation and customize its display. You can also anchor the annotation to a specific location.

Map

The GIS map displays entities (wells and groups) as long as their attributes include geographical coordinates.

When you mouse over the GIS map, the status bar displays the latitude, longitude, and dominion land survey (DLS) at the current location.

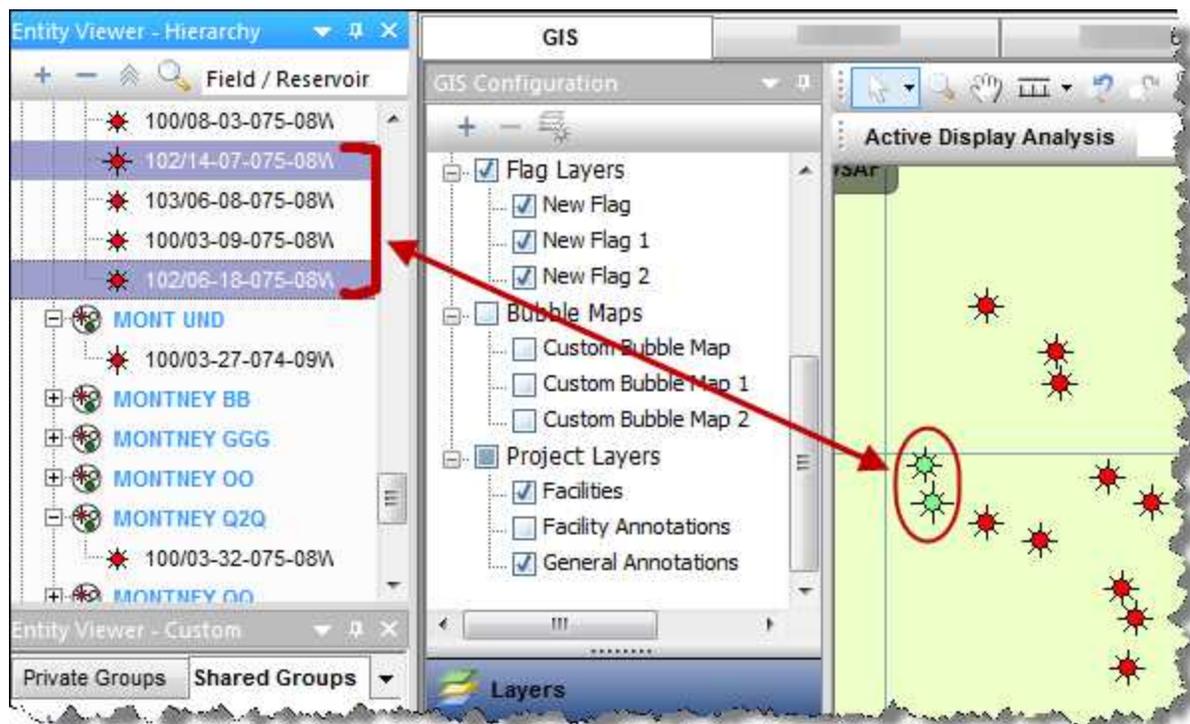


The GIS map supports three datum systems / projections:

1. NAD 27 (North American Datum, created in 1927)
2. NAD 83 (North American Datum, modified in 1983)
3. WGS 84 (World Geodetic System, modified in 1984)

To create new facilities, click the icons located on the GIS design mode tools toolbar. If you want other options (for example, setting a flag), right-click the well on the map.

When you select a well on the map, it is synchronized with the Entity Viewer and vice versa. Selected wells are highlighted in the Entity Viewer and are displayed in light green on the GIS map.



Context menus

If you right-click the map, you can add a general annotation by selecting **Create General Annotation**. This anchors the annotation at the point on the map you clicked.

If you right-click an annotation, you can edit it.

If you right-click a well on the map, these options are displayed:

- **Flags**
 - **Create New Flag** — adds a flag layer for this well and displays the flag properties in the GIS Configuration pane.
 - **Delete Flag** — deletes the flag for this well.
 - **Add Selection to Flag** — select your flag from the submenu.

- **Remove Selection from Flag** — this option is enabled if a flag layer is already in place. Delete the appropriate flag by selecting it from the sub-menu.
- **Flag Properties** — displays the flag properties in the GIS Configuration pane.
- **Bubble Maps**
 - **Create New Bubble Map** — opens a dialog box where you can create and customize your [bubble map](#).
 - **Add to Bubble Map** — select your bubble map from the submenu.
 - **Remove From Bubble Map** — this option is enabled if a bubble map is already in place. Delete the appropriate bubble map by selecting it from the submenu.

Layers

Layers are graphical strata that you can display on top of the GIS map. Layers include gridlines, geopolitical borders, and well icons. You can show and hide layers by selecting or deselecting items in the tree structure.

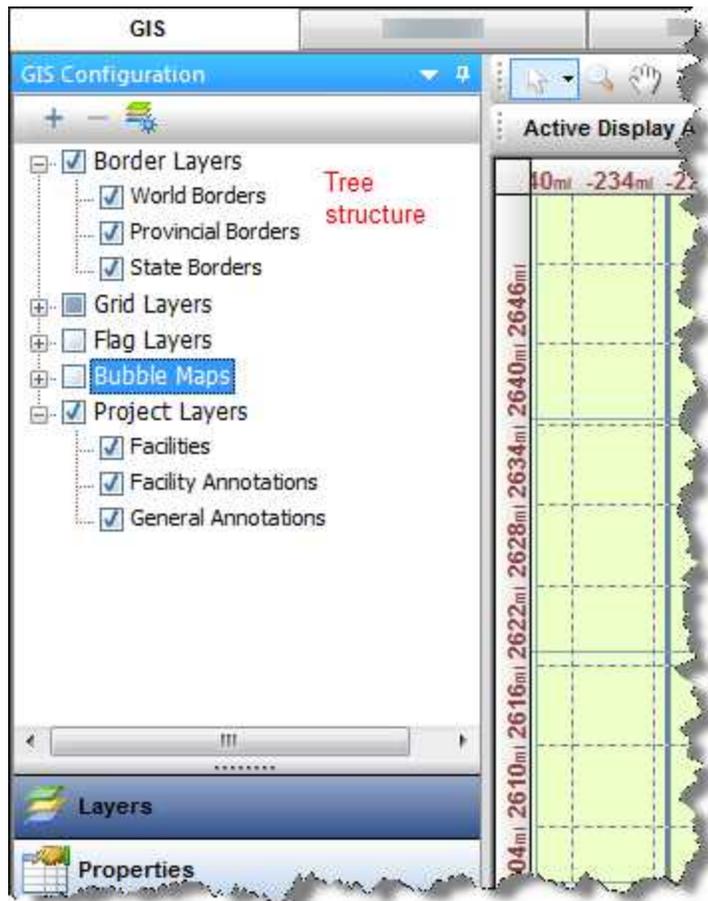
Tip: All layers are user-specific. Therefore, any layers you create are not seen by other users in a multi-user environment.

Layers include the following:

- **Border Layers** — displays the political borders for all countries, the provincial borders in Canada, and the state borders in the United States.
- **Grid Layers** — displays each of the available coordinate systems. The [DLS](#) and [NTS](#) coordinate systems are only available within certain regions.
- **Shapefile Layer** — a shapefile is a collection of files that contains simplified geo-spatial and attribute information to describe points, arcs, and polygons. These points and shapes represent objects or locations on a map (for example, a well, a lake, or political borders). For more information, see [shapefiles](#).
- **Image Layer** — any image (for example, a photograph) can be imported as an image layer. While importing an image file you are prompted to set desired coordinates for three points on the image. These points are used to position the image on the GIS map.

- **Project Layers** — includes all wells / facilities and annotations.
 - **Facilities** — this layer includes all wells and meter stations.
 - **Facility Annotations** — annotations connected to a specific entity (such as, wells) that display selected attribute and analysis information. For more information, see the [Facility Annotation Editor dialog box](#).
 - **General Annotation** — annotations to be displayed on the GIS map. While adding a general annotation, you can customize the text, appearance, and position.
- **Bubble Map Layer** — bubble maps graphically represent attributes associated with wells and other entities. For more information, see [bubble maps](#).
- **Flag Layer** — flags are similar to bubble maps, but they do not reflect well attributes. Instead, they are simple markers that can be used to designate individual or multiple entities. For more information, see [flags](#).

By default, layers are displayed with Project Layers being drawn on top of the GIS map, followed by Grid Layers, and Border Layers. This corresponds to Project Layers being at the bottom of the tree structure and Border Layers being at the top.



To change your display order, drag the category in the tree to your new location.

Note: Drawing layers on top of others may hide certain information. You can avoid this by setting the transparency of the top layer by right-clicking it in the tree and editing its properties.

Shapefiles

With Harmony Enterprise, you can only select shapefiles with the .shp extension, but shapefiles usually contain a collection of files with different extensions. Harmony Enterprise uses the following file types to make the import process faster and more accurate:

- **DBF** — contains shapefile information and labels for the data. (The information this file contains is used when shapes are converted to facilities.) This file is the least critical; if it is missing, the shapefile is still imported.

- **PRJ** — contains the datum for the shapefile in projection, unit, datum format. (Harmony Enterprise supports NAD27, NAD83, and WGS84.) If this file is missing, the shapefile may not be placed in the correct location.
- **SHX** — loads individual shapes from the file. This file reads the bounding boxes of an area and works as a sort of index for the .shp file, so that all the data contained in the .shp does not need to be cached. If this file is missing, loading may be slow and more memory may be consumed.

These files make using shapefiles easier, so we recommend keeping them together in the same directory.

Compatibility

If you encounter issues importing a shapefile, it may be because your shapefile is incompatible with Harmony Enterprise. Ensure that your shapefile meets the following requirements:

- Mercator projection
- Geographic coordinate system (GCS)
- NAD 27, or NAD 83, or WGS 84
- Latitude and Longitude in decimal degrees

Facility Annotation Editor dialog box

This dialog box is commonly used when you click the Annotation Display Options icon on the GIS toolbar.

Important: Clicking **OK** applies your changes to all your annotations *excluding* those that have been individually modified by right-clicking specific annotations. Clicking **Apply to All** updates every annotation.

- **Search** — type a search term in this field, and results are automatically displayed.
- **Attributes** — select the attributes you want displayed in your annotation.
- **Results** — select the results you want displayed in your annotation.
- **Include in Apply to All** — if you select this checkbox, the settings in the Label Position section are applied to all of your wells when you click **Apply to All**. When this checkbox is deselected, only the well annotations that have not been individually edited are modified.

- **Angle** — sets the angle that the annotation is offset at from the well. A negative value is rotated counterclockwise from the well.
- **Distance** — sets the distance (in inches) that the annotation is offset at from the well.
- **Display** — select one of the display options for title, value, and unit.
- **Draw Settings** — if you select **Frame**, a box is drawn around your annotation. If you select **Anchor**, your annotation is fixed to the well.
- **Background** — set your background color and transparency for the annotation.

Bubble maps

Bubble maps provide a means of graphically representing attributes and analyses associated with specific wells.

Bubble maps are represented as layers within the GIS tab, and can be selectively enabled or disabled like other layers. To create these graphic representations, a colored shape is overlaid on the entity. Both the color and the shape reflect one of the properties associated with the entity. As the value of the property changes, the color changes within a set range. In more complicated cases, multiple properties can be associated with different settings including variations in color, size, angle, and shape, according to the scale you set.

To show or hide the bubble map, select or deselect it in the tree structure.



To add / create a bubble map, start by selecting wells for the bubble map. In the GIS Configuration pane, click the + icon and select **Add Bubble Map Layer**.

Create Bubble Map: Select Name and Type

Name: _____

Custom Bubble Map

Select the Bubble Map type: _____

Bubble

Drainage Area

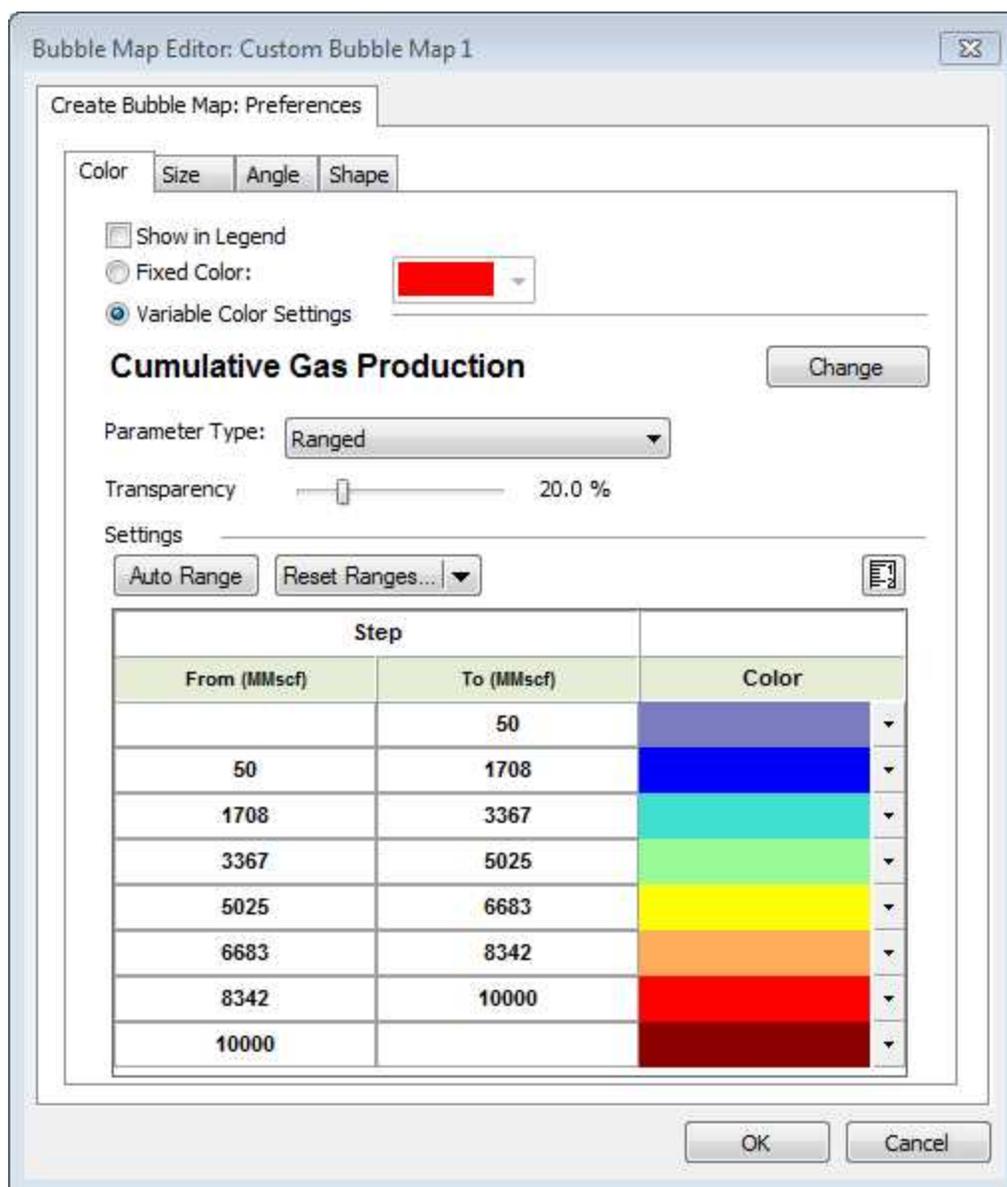
Analysis for Drainage Area: _____

Analysis 1

< Back Next > Cancel

Type a name for your bubble map layer and click **Next**. If you create a bubble map with the same name, a number is incrementally added to the name (for example, custom bubble map 1, custom bubble map 2, and so on).

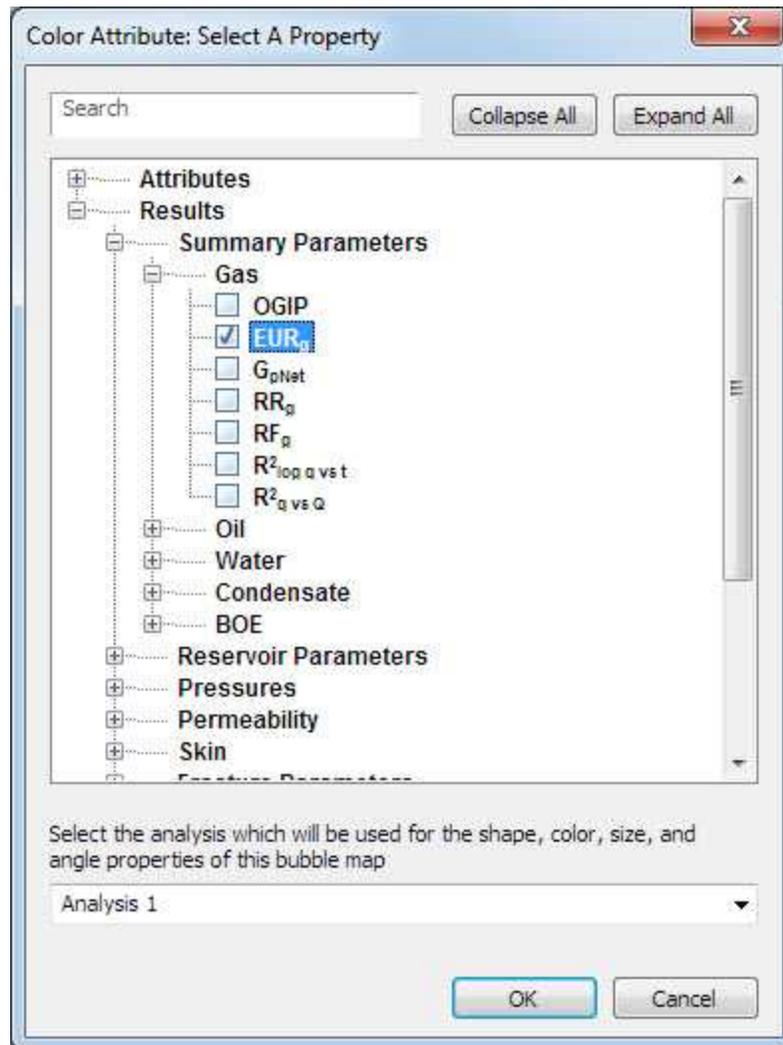
Each tab in Preferences enables you to customize a different property that varies with well properties. (Fixed settings are used by default.)



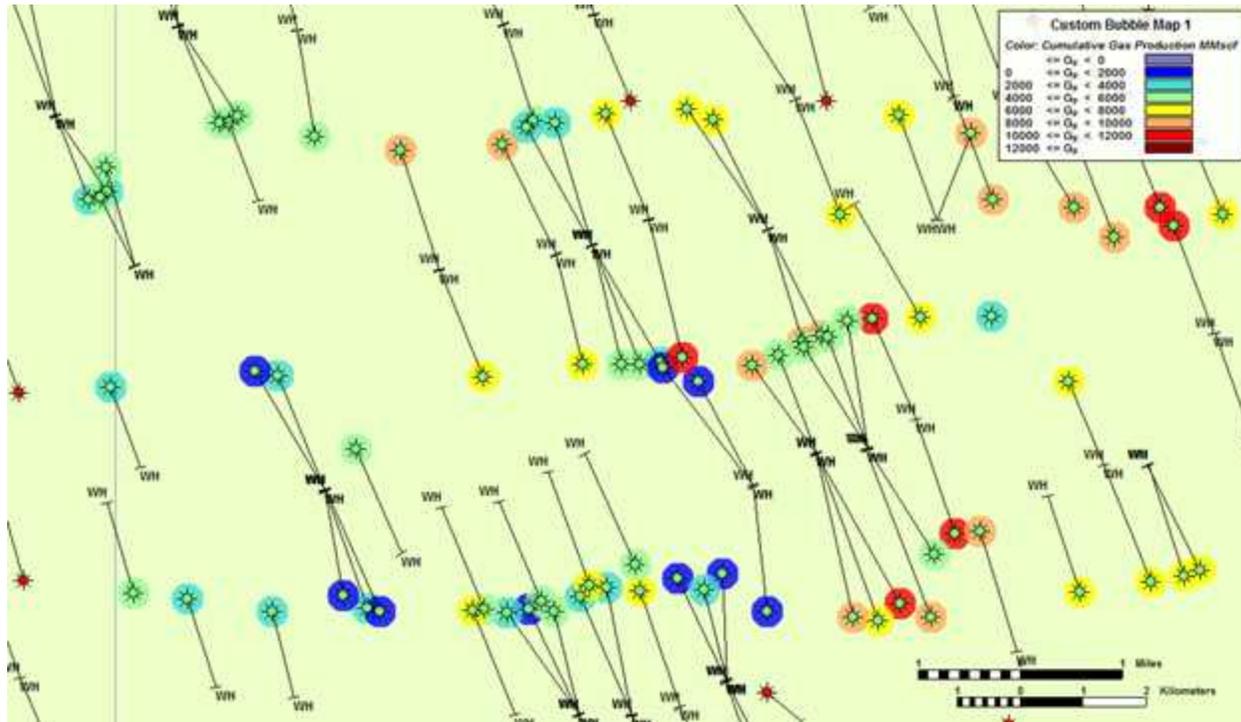
- **Show in Legend** — select whether this property is displayed in the legend. If the property is using a variable color setting, by default, the property is displayed in the legend.
- **Fixed Color / Size / Angle / Shape** — all wells show the same property, as set in the dialog box.
- **Variable Color / Size / Angle / Shape** — select an attribute or analysis result on which to vary the property. When selecting analysis results, an analysis name must also be selected.

- **Parameter Type:**
 - **Ranged** — the color, size, etc. displayed corresponds to a range of property values for each parameter.
 - **Set Point** — the color, size, etc. displayed corresponds to a specific value for each parameter.
- **Transparency** — use the slider to set the level of transparency / opacity for your bubbles.
- **Auto Range** — for each ranged property, Harmony Enterprise automatically detects the appropriate range and division to separate values.
- **Reset Ranges** — reverts back to a previously saved range, or to the default values.
- **Change** — when you click this button, the <Color> Attribute: Select a Property dialog box opens.

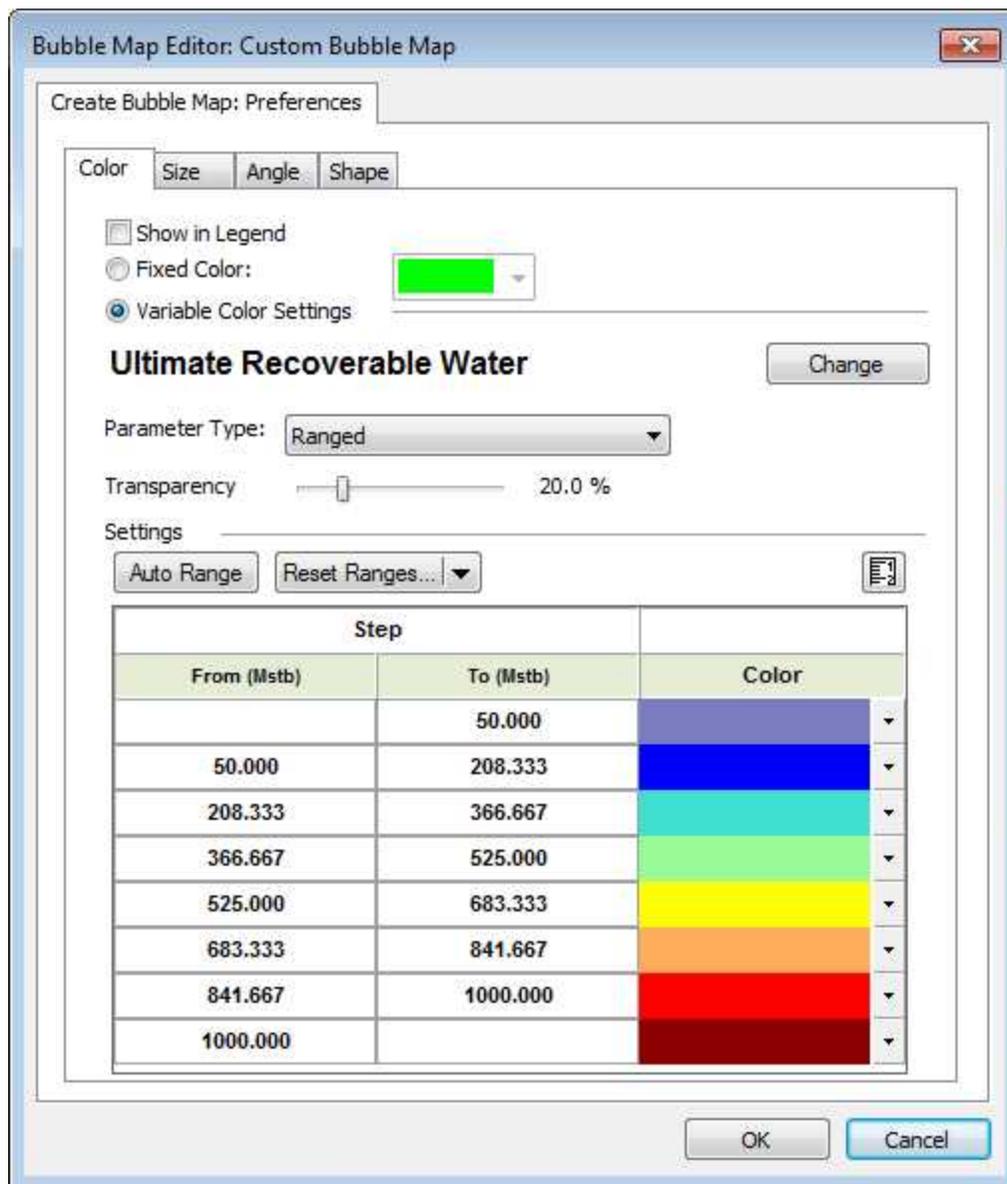
Select the attribute / result from the tree structure.



- **Search** field — type your search term to find attributes or analysis results.
- **Analysis** drop-down list — select the analysis to populate values for the selected property. Note that this only applies to the Results tree structure, and does not apply to attributes.



To edit an existing bubble map, right-click it in the tree structure and select **Options**. If you click **Variable Color Settings**, the **Change** button is enabled and you can set the <color> for a specific attribute.



To add wells to an existing bubble map, select the well, right-click it and select **Bubble Map, Add to <bubble map name>**.

Drainage area maps

A drainage area map is a bubble map (plotted as a circle), which plots the drainage area of a well to scale on the GIS map, based on the area each well is draining. While traditional bubble maps can plot drainage areas, they only show relative areas, with the size of the bubble corresponding to the range you set.

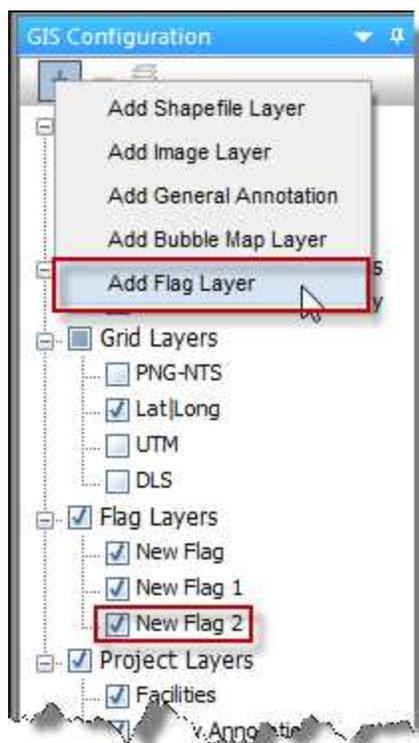
Note: If the drainage area is small, you may have to zoom in to see the bubble map.

To add a drainage area map, see [bubble maps](#). Note that with drainage area maps, color is the only variable preference that can be set.

Flags

Flags are similar to bubble maps, but they do not reflect well attributes. Instead, they are simple markers that can be used to designate individual or multiple entities.

If you add a flag layer (click the + icon on the GIS Configuration pane), a corresponding node in the tree structure is added. You can show or hide flags by selecting or deselecting their check-boxes.

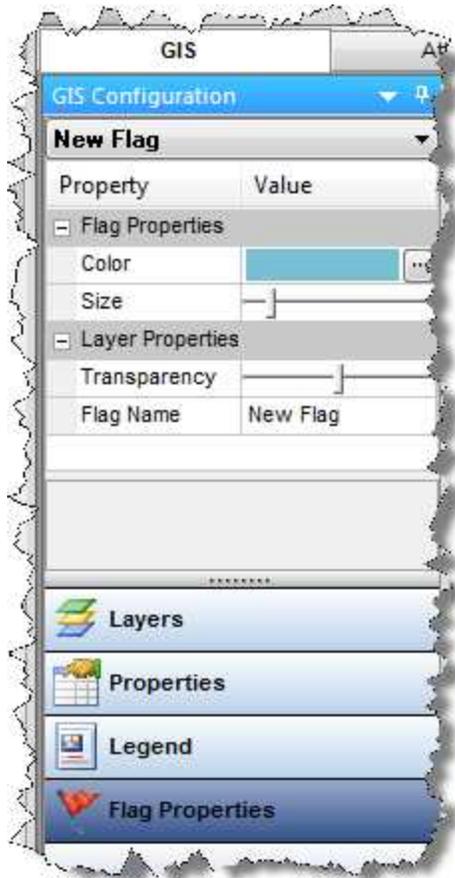


To add wells to an existing flag, select the appropriate wells on the GIS map, and then right-click and select **Flags, Add Selection to Flag**.

To modify flags, right-click the flag in the tree structure and select **Flag Properties**. Edit your flag's name, color, size, or transparency.

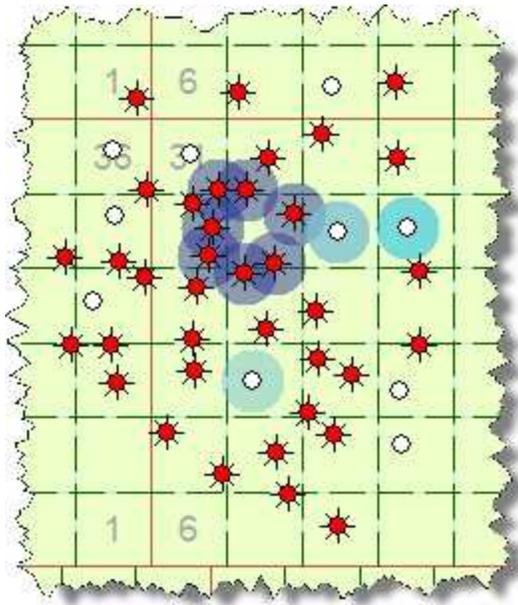
Flag properties

When you click the Flag Properties button at the bottom of the GIS Configuration pane, you can edit the appearance of flags displayed on top of entities on the GIS map. The drop-down list at the top of the pane determines which flag is being edited.



- **Color** — click the ... button and select the color for the selected flag.
- **Size** — click the slider to increase or decrease the size of the circle displayed on the map for the selected flag.
- **Transparency** — click the slider to increase or decrease the transparency of the selected flag. Moving the slider to the left, makes the flag more opaque, and moving the slider to the right, makes the flag more transparent.
- **Flag Name** — use this field to type a name for the selected flag layer.

Flags are similar in appearance to bubble maps, but they do not reflect well attributes. Instead, they are simple markers that can be used to designate individual or multiple entities.



Flags are represented as layers on the GIS map, and can be selectively enabled or disabled like other layers.

Import functionality

To prevent other users from modifying data at the same time, wells must be locked while they are imported. Importing a new well does not impact other users because the well is not visible to them until the well import is complete. However, when you are updating existing wells, these wells are locked to other users. If Harmony Enterprise is unable to lock a well during importing or updating, the update of this well fails, and an error message is displayed in the Status Window.

Import functionality includes the following:

- Scheduling well updates
- Scheduling auto refresh results (for FMB & URM)
- Import Data dialog box
- Link Incoming Wells to Existing Wells dialog box
- Updating existing wells
- Data Reduction dialog box

Scheduling well updates

In most cases, scheduling well updates refers to specifying a time to import additional data for one or more wells. For more information, see [Windows Task Scheduler](#) and [command line](#).

Note: This functionality does *not* apply to SE licenses.

You can schedule well updates on a one-time basis using the [Import Database wizard \(step 13\)](#), or automatically using the auto-import feature. If you decide to import your wells automatically, you can schedule imports to occur outside of business hours on a recurring basis without using a Harmony Enterprise license. For more information, see the [Import Options dialog box](#).

In order to schedule well updates, you need:

- permission to modify and execute tasks. If adjustments are needed, see your IT department.
- permission to import data. For more information, see [role-based security](#).
- to be logged in to Windows when the updates occur. Note that locking your computer is fine.

After your automatic well import is complete, a log file is generated, which is viewable by double-clicking the summary message in the [Status Window](#).

Troubleshooting

You can customize well-linking-logic in Harmony Enterprise 2019.3. Well-linking-criteria selections are saved with other Scheduled Import settings. Pre-existing scheduled imports will persist when upgrading, but they will not contain well-linking-criteria selections. Existing scheduled imports will be aborted, and that information is reported in the Status Window, as well as in a log file.

To fix your pre-existing scheduled imports, you only need to revise your existing scheduled imports *once* by configuring the well-linking-criteria hierarchy for each saved database connection. Your selections are saved, and scheduled imports resume during their regular time frame. For more information, see [importing well data from a database](#) and the [Well Linking Criteria dialog box](#).

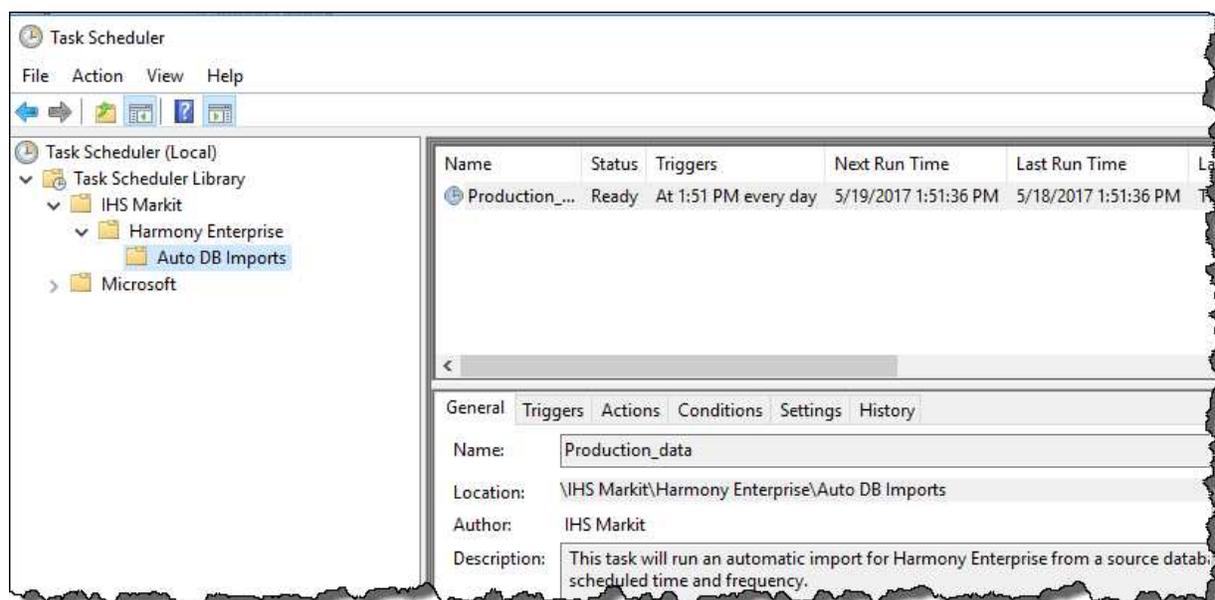
Windows Task Scheduler

The Windows Task Scheduler is commonly used when setting Auto Import options in the [Import Options dialog box](#).

To use the Task Scheduler:

- Type a name for your task.
- Set a start date and time.
- Select the frequency of the task from the drop-down list (that is, daily, weekly, or monthly).
- To rename your task, type a new name in the Task Name field, and click **Save Task**.
- To save your task, click **Save Task**.
- To delete your task, click **Delete Task**. (You are *not* prompted to confirm your decision.)

When your task is scheduled, you can preview it in the Task Scheduler.



Command line

Command line is commonly used when setting Auto Import options in the Import Options dialog box.

Copy and paste the text in the Program and Arguments fields to your application or script. If you are not able to open a Command prompt, you may need to contact your IT dept.

Command line arguments include the following (see the Example below):

- **Harmony Enterprise Database** — the data source name (DSN). This is the defined connection to your data source.
- **Database Connection Name** — automatically connects to the connection you previously set up.
- **Options** — update options can be specified with a single letter. For more information, see Options below.
- **Calculate Sandface Pressures (Wells)** — type **y** (yes) to automatically calculate sandface pressures on wells when importing. If you type **n** (no), sandface pressures are not automatically calculated.
- **DataReduction** — type **y** (yes) to perform automatic data reduction based on your default settings for all wells. If you type **n** (no), no data reduction is done.
- **Calculate Sandface Pressures (Scenarios)** — type **y** (yes) to automatically calculate sandface pressures on Scenarios when importing. If you type **n** (no), sandface pressures are not automatically calculated.

Example

A command line example is as follows:

```
"C:\Users\Public\Documents\Harmony Shared\Harmony Enterprise 2021.1\HarmonyExamples.hldb" -AutoDBImport "MyConnection" -Options "nnonn" -Autocalcs "n" -DataReduction "n" -ScenarioAutocalcs "n"
```

Harmony Enterprise Database	Database Connection Name	Options	Calculate Sandface Pressures (Wells)	Data Reduction	Calculate Sandface Pressures (Scenarios)
"C:\Users\Public\Documents\Harmony Shared\Harmony Enterprise 2021.1\HarmonyExamples.hldb"	-AutoDBImport "MyConnection"	-Options "nnonn"	-Autocalcs "n"	-DataReduction "n"	-ScenarioAutocalcs "n"

Note: In this example, since the Options parameter is set to "nnon", data is imported as follows: Production Data = merge no overwrite, Attributes & Properties = new, Analysis Data = overwrite, Wellbore = new, and Static Pressure = new.

Options

Command line options are as follows:

Data Type	Import Options	Abbreviation
Production Data	Append	a
	Merge no overwrite	n
	Merge with overwrite	o
	Discard and replace	d
Attributes & Properties	Ignore	d
	New	n
	Overwrite	o
Analysis Data	Ignore	d
	New	n
	Overwrite	o
Wellbore	New	n
	Append	a
	Discard and replace	o
	Ignore	d
Static Pressures	New	n
	Overwrite	o

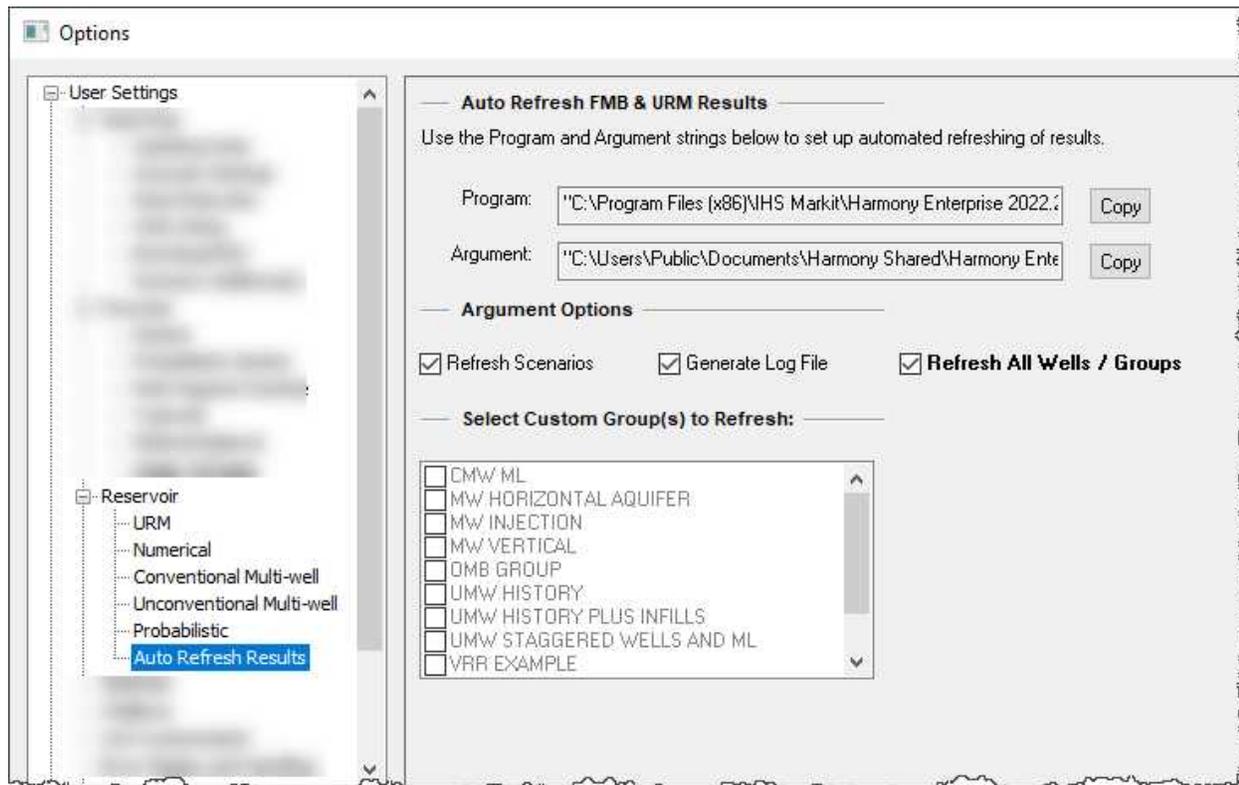
For a description of import options, see [updating data](#).

Scheduling auto refresh results (FMB & URM)

When new production data is imported, [FMB](#) and [URM](#) analyses (for groups, wells, and scenarios) can be recalculated. You can manually select wells in the [Entity Viewer - Hierarchy](#), right-click them and recalculate results, but this can be time-consuming.

To schedule automatically refreshed results:

1. Open the [Options dialog box](#) and click the **Auto Refresh Results** node.



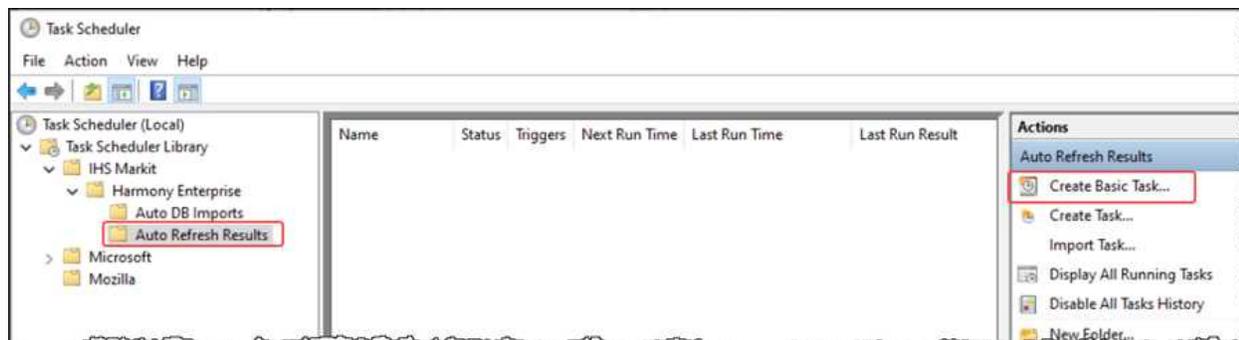
- By default, all wells and groups are updated. In order to select Custom Groups from the list at the bottom of the dialog box, deselect the **Refresh All Wells / Groups** option. As you select Custom Groups, Program and Argument strings are automatically generated.

Assignment Options:

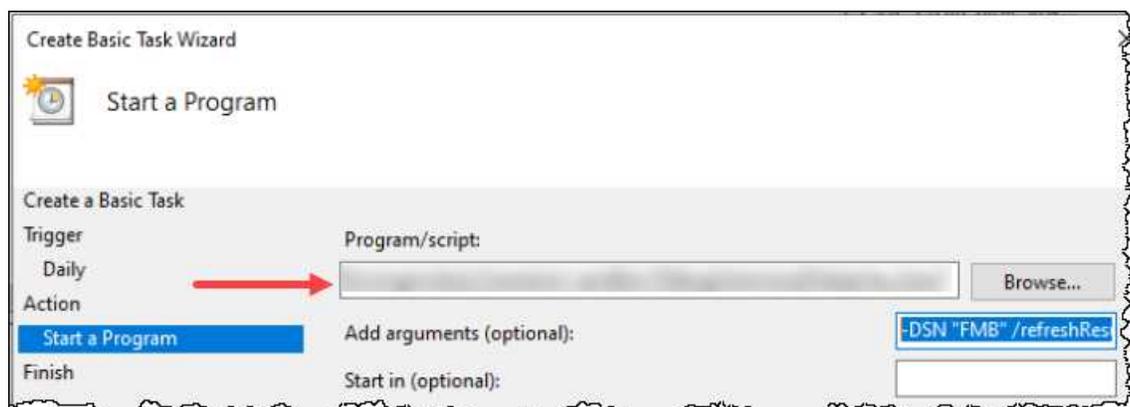
- **Refresh Scenarios** — corresponds to **-Scenarios** in command line, and controls whether scenarios should also be refreshed. The default setting is “True”.
- **Generate Log File** — corresponds to **-Log** in command line, and overrides the Program's logging state. If **-Log** is followed by “False”, Harmony Enterprise does not create a text log of refreshing the results. The default setting is “True”.
- **Refresh All Wells / Groups** — corresponds to **/refreshResults** in command line, and this is the main argument and must be followed by a string of entity IDs separated by a semicolon. If the string is left empty, all entities in the database with an FMB or URM analysis are updated (unless the **-Scenario** argument prevents it).

- Click the **Copy** button in the Program section.
- Open the Windows Task Scheduler.

5. In the left-side pane, navigate to the **Task Scheduler Library, IHS Markit, Harmony Enterprise, Auto Refresh Results** folder.



6. Click **Create Basic Task**. Type the required information: Name, Description, and Trigger (when the task is to occur).
7. For Action, select **Start a Program** and then paste the Program string from [step 3](#) into the **Program / script** field.



8. Similar to the previous step, copy the Arguments string into the **Add arguments** field.
9. Click **Next**, then **Finish**.

The new task runs at the trigger interval, and Harmony Enterprise opens and refreshes the specified results. After the task is complete, Harmony Enterprise closes.

Note: Auto-refreshing results generates a log file (unless overridden by the - Log argument), which is located at: C:\Users\\Documents\FAST\Harmony Enterprise <version number>\RefreshResultsLogs

Things to keep in mind:

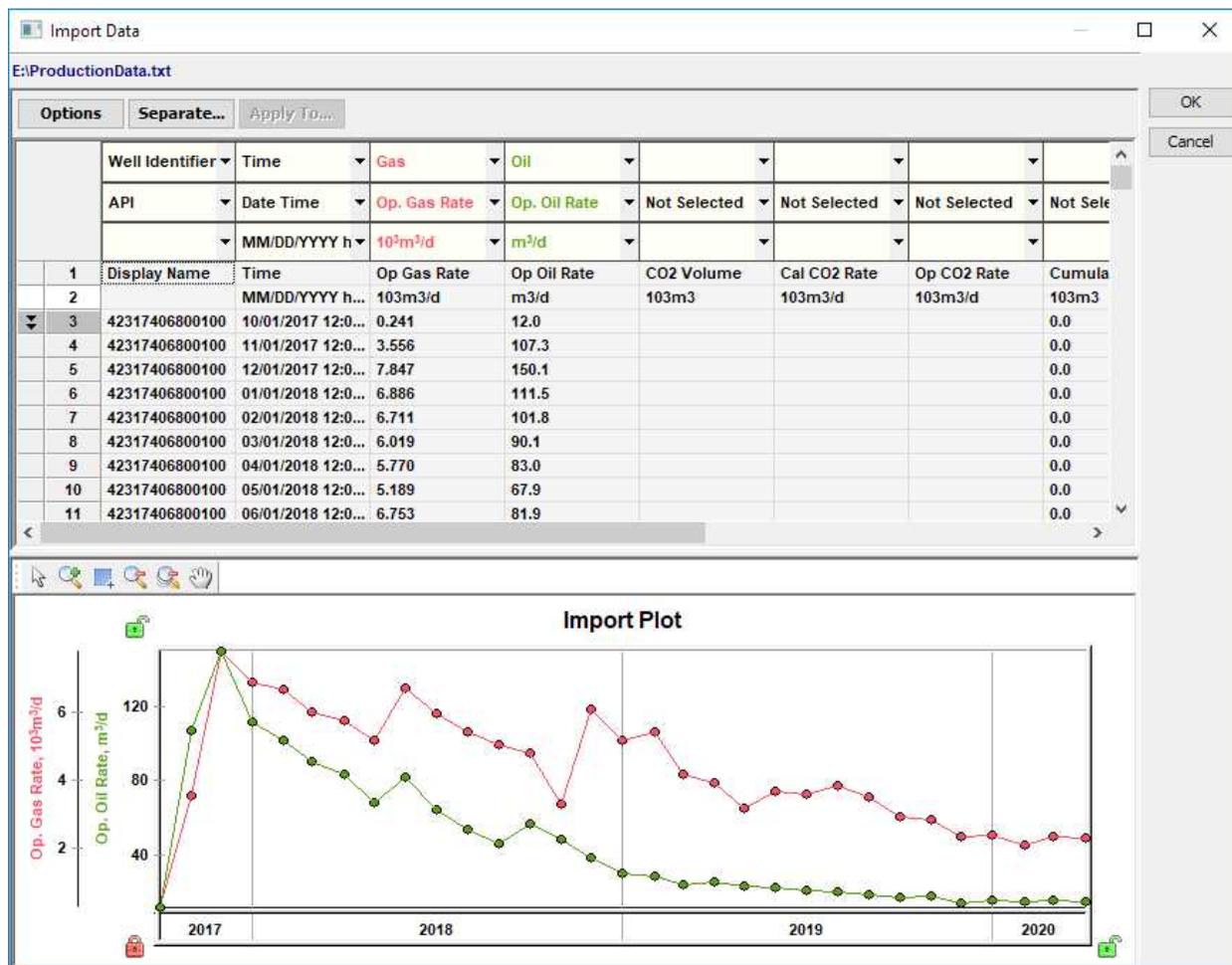
- you can only update custom groups.
- the string in the Arguments field has a GUID that applies to the GUID for the entire custom group.
- setting up automated scheduled recalculations is best handled by experienced database administrators because they access to the GUIDs.
- a best practice is to import production data and update sandface pressures (see scheduling well updates) *before* updating FMB or URM.

Examples:

- -DSN "FMB" /refreshResults "FD692F72-8FD2-489F-A6E0-C3C42DF6E0A5;XX699Y76-8FW3-721A-A9D0-Z3T67DF6E0A9" -DSN "FMB"
- -Log "False" -Scenarios "False" /refreshResults ""

Import Data dialog box

This dialog box is commonly used when you import well data from a file. The main purpose of this dialog box is to assign column headers (by clicking the drop-down arrows) to your data, which brings this data into Harmony Enterprise.



Toolbar

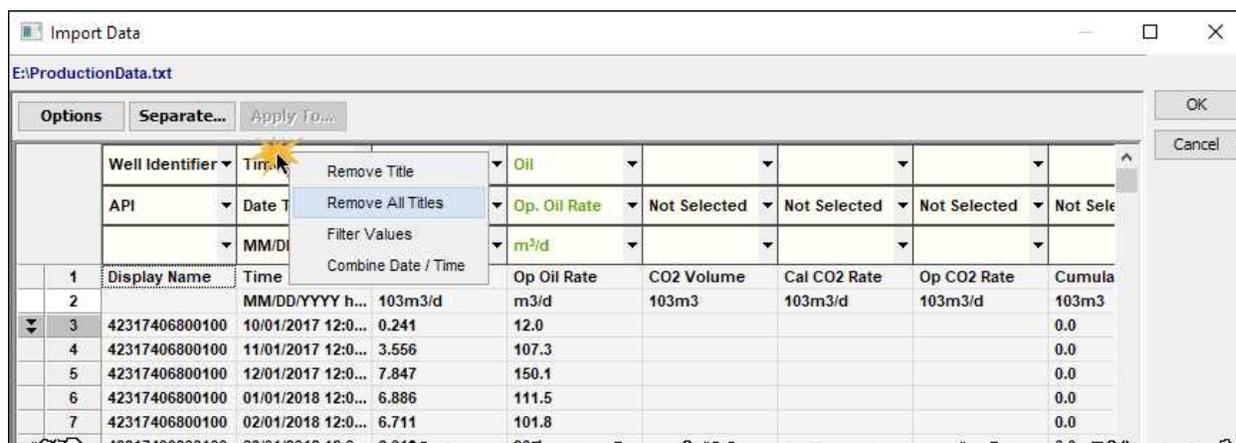
This dialog box has these buttons on its toolbar:

- **Options** — opens the Import Options pane.
- **Separate** (Production data only with multiple wells in one file; not applicable to attributes) — if you specify a Well Identifier for your first column and click **Separate**, multiple wells in the same file are listed as tabs, which divides the single import file into multiple entities for import.
- **Apply To** — applies the column headers you have set in one worksheet to all of the other worksheet tabs in the spreadsheet file. The single import file generates multiple entities for importing, with each one named according to the original worksheet name.

Context menu

Right-clicking any of the headers lists these options:

- **Remove Title** — reverts this column to the initial “Not Selected” state.
- **Remove All Titles** — reverts all columns to the initial “Not Selected” state.
- **Filter Values** — prevents the import of a specified value for that column.
- **Combine Date / Time** — takes a date column and a time column and combines them into a single column before importing.



Import Options pane

This pane opens when you click the **Options** button.

The screenshot shows the 'Import Data' window with the following components:

- Table:** A table with columns: Well Identifier, Time, Gas, Oil, and CO2 V. It contains 10 rows of data for well 42317406800100, showing gas and oil rates from 2017 to 2020.
- Import Plot:** A line chart showing 'Op. Gas Rate, 10³m³/d' (red line) and 'Op. Oil Rate, m³/d' (green line) over time from 2017 to 2020. The gas rate starts at approximately 0.241 and fluctuates, while the oil rate starts at 12.0 and generally decreases over the period.
- Import Options Dialog:** A dialog box on the right with sections for:
 - Local Atmospheric Pressure:** 101.325 kPa(a)
 - Standard Conditions:**
 - Metric:** Standard Temperature: 15.000 °C, Standard Pressure: 101.325 kPa(a)
 - Field:** Standard Temperature: 60.000 °F, Standard Pressure: 14.650 psi(a)
 - Rows:** Start Import from row: 3, End Import at row: 33
 - Template:**
 - Save format for this file while importing
 - Save current format as default while importing
 - Remove default format (if it exists) while importing

You can change import options, including the standard operating conditions of the file to be imported, and the configuration of the unit list.

Rows

(You can also right-click rows to set this range.)

- **Start Import from row** — set the first row number in the table that you want to import.
- **End Import at row** — set the last row number in the table that you want to import.

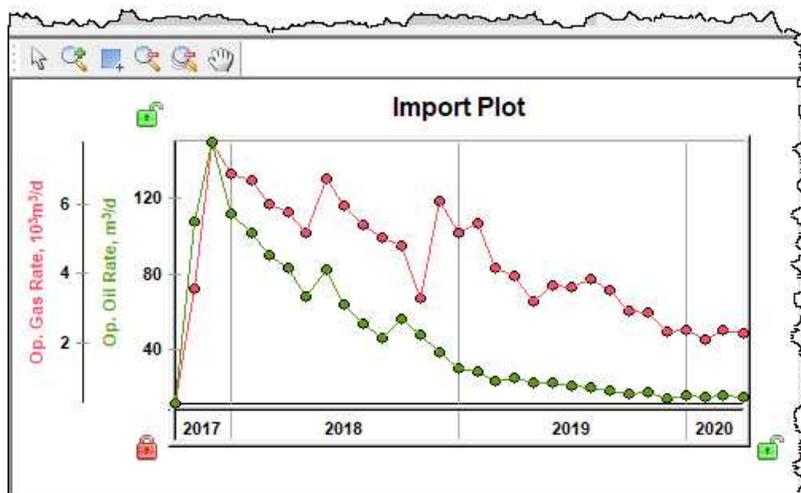
Template

- **Save format for this file while importing** — saves your column and row mapping for this file.

- **Save current format as default while importing** — saves your column and row mapping as the default setting for other files.
- **Remove default format (if it exists) while importing** — resets your settings, so you can remap columns and rows.
- **Save current format as** — saves your current mapping as a template.
- **Saved Formats** — select the saved formats you want to apply or delete.
- **Multi-level unit picker** — when selected, the column-mapping menus display the menu items horizontally in multiple columns, instead of the default setting of a single vertical column.
- **Continuous time track** — this option is selected by default for cumulative time. If you deselect this option, gaps in your order, as determined by irregularities in the data sampling interval, are interpreted as shut-ins. For additional information, see [continuous time track](#).
- **Sample interval for Date / Time matching** — we recommend keeping the default setting. This option specifies the interval for comparisons. For example, every 50 rows a comparison is performed on the date / time column to verify if the format is acceptable.
- **Date / Time Sensitivity Level** — we recommend keeping the default setting. You can use the slider to specify how closely a format has to match. For example, a 100% setting means that the imported file has to match your format exactly.

Import Plot section

Data is plotted for a single well import, if you have a time column (x-axis) and appropriate data (y-axes). Note that the preview plot does *not* display data, if you are importing multiple wells in the same worksheet, or if you are importing attributes.



Link Incoming Wells to Existing Wells dialog box

If at least one well matches the criteria below, this dialog box opens after the import process is complete. All of the wells that meet any of these conditions are listed:

1. Wells that have multiple potential matches to existing wells.
2. Wells imported without a well identifier (for example, a *.csv file for a single well).
3. Wells with potential matches that cannot be updated due to access restrictions in Well Security (see [configuring well security](#)) are skipped, and an error message for the well is displayed.

The OK button is enabled after the incoming wells are linked up and are displayed in the Linked Well (Incoming | Existing) pane. In other words, incoming wells cannot be imported unless they are linked to existing wells, or are categorized as new wells.

In this dialog box, you can:

- Display which incoming wells are linked, and which are not, as a result of the auto-mapping process.
- Link an incoming well to a well in the database manually.
- Compare the production data for any two wells (one from the import, and the other from the database, or from a pair of linked wells).
- Compare the well attributes of two or more wells (one from the import, and the other(s) from the database).

The options in this dialog box include the following:

- **Display Wells by** drop-down list — the default setting is Entity Name. Any Entity Header attributes containing data can be selected to identify wells, and they set how the wells are displayed in this dialog box.
- **Link by** drop-down list — the default setting is Import Linking Criteria. With this setting, you can select a header that was not initially used in import linking and trigger matching based on the secondary setting. For example, if you are importing wells and the linking criteria is set to match on API and you have duplicate existing wells for an incoming well, you can have a secondary match on the Entity Number. By clicking the **Auto Link** button (described below), the incoming well is linked to an existing well with matching on Entity Number.
- **Incoming Wells** section — lists incoming wells that have not been linked up.
- **Link** button — links a single well from the incoming list to a single well from the database list. After a link has been made, the two linked items are moved to the Linked Wells pane. This button is disabled if the two selected items are not compatible. For example, in an unallocated .dp2 or .298 file, a meter station cannot be linked to an unallocated well.
- **New well** button — enabled when incoming wells are selected that are not currently in the database. Clicking this button moves the selected wells to the Linked Wells pane.
- **Ignore well** button — enabled after you select a well(s) in the Incoming Wells pane. By clicking this button, you can exclude these wells from the import process.
- **Existing Potential Well Matches** section — lists wells in the database that are a potential match for the incoming wells based on the Display Link by setting. Or, if the Show all wells option is selected, lists all wells in the database. A well in this list is not updated on import.
- **Show all wells** option — when this checkbox is selected, all of the wells in the database are displayed in the Existing Wells pane.
- **Auto Link** button — clears the current linking results and restarts the auto-mapping process according to the single setting displayed in the Link by field. For more information, see the [Link by description](#). The Auto Link feature operates on a 1:1 basis with wells too. In other words, you cannot auto-map multiple wells to a single well.
- **Unlink** button — removes the items selected in the Linked Wells pane and returns them to their original locations. (If the well ID in a *.harmony file has been used for matching, it cannot be unlinked.)
- **Unlink All** button — removes the links for all of the items in the Linked Wells pane.

- **Reset** button — resets the entire dialog box to its original settings (initial view).
- **Linked Wells (Incoming | Existing)** section — lists the wells that have been linked (incoming to existing), or new wells to be imported. Wells on the left-side of this pane are used to update the corresponding wells on the right-side. Empty wells have only their well name set (their API, DLS, NTS, Production ID, and Well Alias Name are blank) and are listed as new wells in this pane.
- **Compare by** drop-down list — displays the production variables that can be plotted (one at a time).
- **Production** tab — clicking wells in either the Imported Wells or the Existing Wells pane displays the production data for the selected wells. Clicking two wells (one from each of the panes), or a single well in the Linked Wells pane, displays the production data for both wells. Data from the database is displayed in black, while data from the incoming well is displayed in the color of the primary fluid. The plot is disabled when more than one item is selected in the Linked Wells pane.
- **Attributes** tab — clicking wells in the Incoming Wells pane displays their corresponding data in the Attributes tab. Subsequently clicking one or more wells in the Existing Wells pane displays their corresponding data in the Attributes tab.
- **Stop Import** — stops the import process of wells that do not have a 1:1 mapping.
- **Cancel** — cancels the current batch of wells that do not have a 1:1 mapping.
- **OK** button — completes the import of well data, including the addition of new wells, and linking incoming wells to existing wells as specified.

Note: Meter stations cannot be manually linked up in Harmony Enterprise. If meter stations exist in an imported .298 or .harmony file, they are automatically brought into a project when they are imported.

Updating existing wells

When you import wells, Harmony Enterprise checks for links to existing wells, so you can merge existing data, instead of creating new wells. Linking is done using the Entity Headers in the Attributes tab (excluding custom headers). Merging new data to existing wells is handled by your settings in the Options dialog box, Well Linking node.

The following identifiers are used based on the various import types.

Import Format	Order of identifiers for linking
Database connection	Internal Harmony Well Key External Well Key API Number Sandface DLS Sandface NTS Entity Name Prod ID Entity No Entity Alias Name Propnum
Enerdeq, Dwights files, PowerTools	API Number Prod ID
Harmony file, .hldb file	Internal Harmony Well Key API Number Sandface DLS Sandface NTS Entity Name External Well Key Prod ID Entity No Entity Alias Name Propnum
IHDC	Sandface DLS Sandface NTS Prod ID
Merak and Lasser (.mer, .axp, .mxp, .vna, and .prn files)	Sandface DLS Sandface NTS API Number
Piper Forecasts	Internal Harmony Well Key
Text (all text files excluding Dwights)	Well Identifier Sandface DLS Sandface NTS API Number Prod ID Entity Name Prod ID

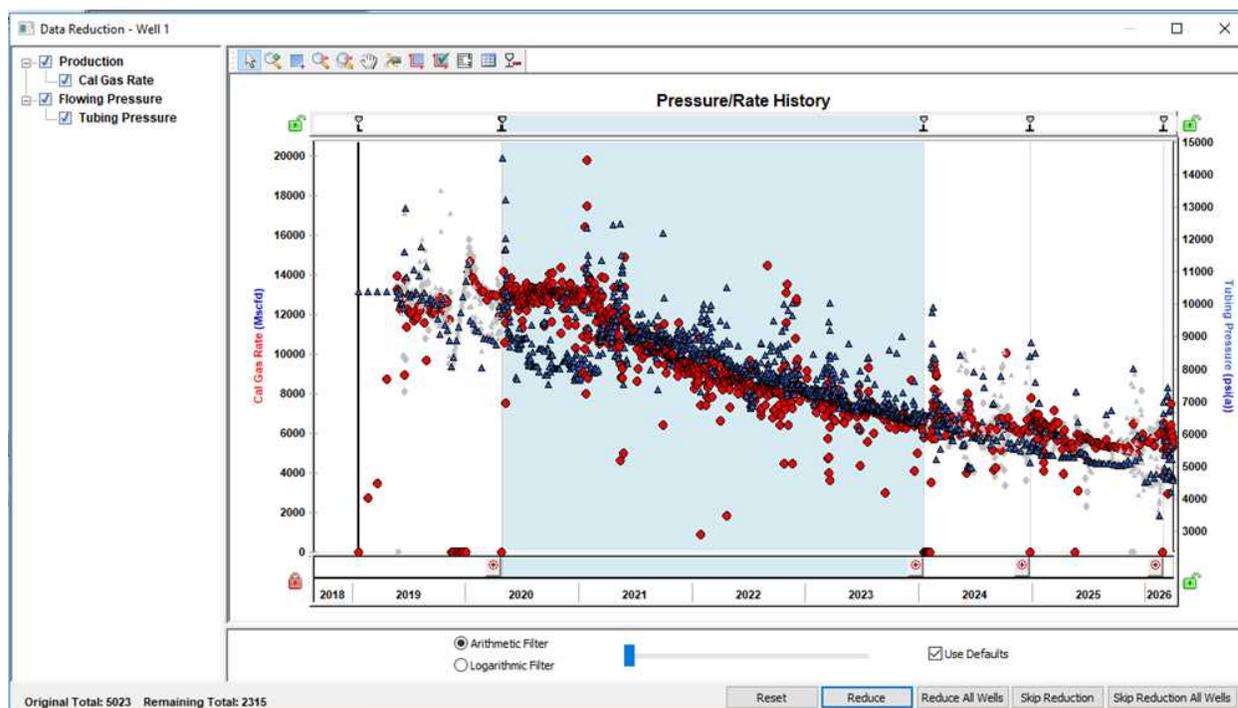
Import Format	Order of identifiers for linking
	Entity Alias Name Entity No External Well Key Propnum
WellTest)	Entity Name

Note: All of the import formats are read-only except for text files and Harmony files. Applying changes in the Options dialog box applies changes globally.

If there are well-matching ambiguities, your input is required. In these cases, the Link Incoming Wells to Existing Wells dialog box opens.

Data Reduction dialog box

Data reduction is the process of reducing high-frequency data prior to importing. This dialog box opens when the number of production rows in a well reaches the threshold defined in the Options dialog box (or the default value of 50,000), or if you have selected the **Always Display** option.



The plot displays the production data categorized automatically with flowing and shut-in periods ("ranges"). Note that automatic detection thresholds for flowing and shut-in periods can be set in [Data Reduction options](#).

The selection tree displays the incoming production data, including producing rates, injecting rates, volumes, and pressure data.

Hovering your mouse over an empty portion of the plot displays the number of points originally in that range, and how many are remaining after applying the current filter. Hovering over a range displays whether you are in a flowing or shut-in period, and whether the range uses default settings. Hovering the mouse over a data point displays that data point's type and date.

With the slider, you can apply a smaller or greater amount of data reduction based on either an arithmetic or logarithmic filter. The slider only applies to the selected range (which is displayed darker on the plot). If you select the **Use Defaults** option, the selected range is filtered based on the [default settings](#).

Toolbar

This dialog box has the following unique icons:

-  **Display Data Reduction Filtering Table** — displays the original and remaining points in each range, and running totals of both. You can select or deselect checkboxes, or click inside a field and enter custom values.

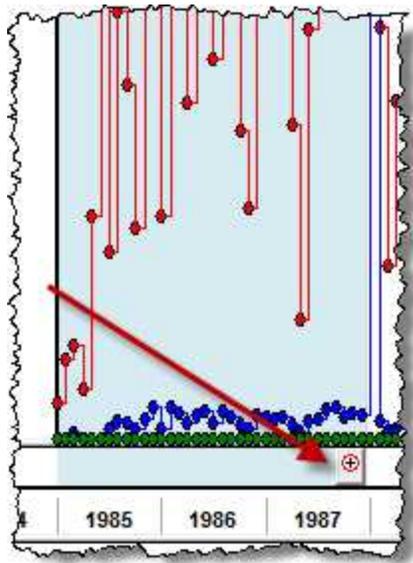
Data Reduction Filtering Table										
	Period	Start Date	End Date	Use Defaults	Arithmetic Filter			Log Filter		
					Use in Period	Points Per Time Step	Target Number of Points	Use in Period	Points per Cycle	Target Number of Points
		DD/MM/YYYY	DD/MM/YYYY			pts/d				
8	Flowing Period 06	23/07/2001	16/12/2002	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	1.000	18	<input type="checkbox"/>	100	18
9	Flowing Period 07	16/12/2002	18/02/2005	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	1.000	27	<input type="checkbox"/>	100	27
10	Flowing Period 08	18/02/2005	10/02/2006	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	1.000	13	<input type="checkbox"/>	100	13
11	Flowing Period 09	10/02/2006	27/03/2007	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	1.000	14	<input type="checkbox"/>	100	14
12	Flowing Period 10	27/03/2007	27/04/2008	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	1.000	14	<input type="checkbox"/>	100	14
13	Flowing Period 11	27/04/2008	01/05/2009	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	1.000	13	<input type="checkbox"/>	100	13

-  **Merge All Ranges** — copies the filter settings to all ranges. For more information, see [adding, resizing, and merging ranges](#).

For information on common plot icons, see [plot toolbars](#).

Zoom

You can zoom into a range by clicking the **Zoom** icon (🔍) in the lower right corner of every range.



To zoom out of the range, click one of the **Zoom Out** icons.

Buttons

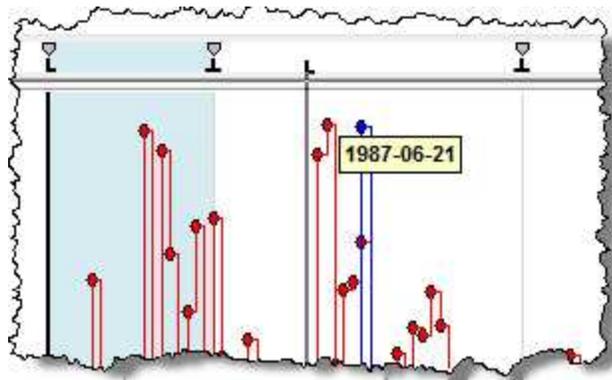
This dialog box has the following buttons:

- **Reset** — resets this dialog box to its initial configuration.
- **Reduce** — reduces the current well's data based on that well's reduction criteria.
- **Reduce All Wells** — reduces the current well's data based on the well's reduction criteria, and all other wells based on the default reduction criteria.
- **Cancel** — imports the current well without applying reduction.
- **Cancel All Wells** — imports all wells without applying reduction.

Adding, resizing, and merging ranges

To add a range:

Click inside the range area just above the main plot area. A marker opens.



To resize a range:

Drag the range marker to the left or right.

Note: You can move any range marker except those at the furthest left and right.

When you merge a range, you copy the filter settings from one range to the next range.

To merge a range:

Click the **Merge All Ranges** icon () in the main toolbar.

Or, right-click a marker and select **Merge Left** or **Merge Right**.

Monitor tab

In this tab, you can monitor the following:

- Production versus forecasts
- Liquid loading

Production vs Forecast sub-tab

In this sub-tab, you can monitor how your forecasts compare to actual production. Therefore, as a prerequisite, you must have overlapping forecasts and production data for a certain period of time. The most common workflow is:

1. Start with production data for one or more wells.
2. Create a forecast or forecasts for each of those wells.
3. At a future date, import additional production data.
4. Compare the existing forecasts against the new production.

Investigate well performance for drop-down list — select a forecast to compare against actual cumulative production.

for <30> days field — type a number of days between 1 and 365 for calculation purposes (30 days is the default value). Note that typing a larger value may influence calculation time.



Calendar icon — select an end date of calculation. For example, if you select August 31st, calculations are run for a production window between August 2nd to 31st (assuming you kept the default value of 30 days). This date defaults to the End of Production for the wells you have selected.

Calculate button — click this button to calculate the cumulative volume difference between actual production and the forecast, as well as percent differences. These calculations apply to the selected well's forecast for all fluid types, or group of wells. Calculations are saved to the database.

Volume variance = cumulative production - cumulative forecast production. A positive difference indicates you are producing more than expected.

% volume variance = cumulative production / cumulative forecast production x 100.

If you select an end date that occurs *after* the last production date, calculations are displayed up to the last date of production, as shown in the **To** column. For example, if you select an end date of Nov 30th, but your production ends on Nov 20th, calculations are shown up to Nov 20th, and the **To** column displays Nov 20th.

Create custom group from selections — see [grouping wells](#).

Note: To copy the full table (all rows) to be pasted into another application, right-click the table and select **Copy Table**, or press **Ctrl-C**.

Tip: If you [export](#) or [import](#) wells with an .hldb file, the data in this tab is not saved, and to have this data, you need to recalculate.

Column sorting

By default, the largest negative cumulative volume is displayed first, sorted by fluid type (that is, gas, oil, water, BOE). Wells are also sorted by status. A red status indicates a forecast has not been found. To fix this, you can select a forecast from the drop-down list, or you can go to the Analysis tab for that well and create a forecast. An orange status indicates incomplete results (for example, missing production data, missing dates, etc.). Be aware that only the first issue with a fluid is reported (for example, no oil production data). A blank status indicates there are no issues.

Note: You can sort tabular data by clicking the column headers. Your first five columns are frozen, so you can keep track of key information as you scroll horizontally.

Selecting a meaningful time period

Since actual production volume can vary substantially, assessing the deviation from a forecast is only meaningful over a defined duration window. The overlapping period of time you select must be sufficiently long enough to minimize the effect of fluctuations in the empirical data, yet brief enough to alert you of any adverse trends. By default, the last 30 days of production are displayed in a tabular format. If there are more than 20 wells, a status bar is displayed after you click **Calculate**.

Grouping wells

After you select entities in the Entity Viewer - Hierarchy pane and click the **Monitor** tab, and then click a well in this tab, the "Create custom group from selections" section opens at the bottom of the tab. Based on your selections, you can create a new custom group. After typing a custom group name and clicking the **Create** button, a new custom group is created in the Entity Viewer - Custom pane.

GIS	Attributes	Diagnostics	Analysis	Eco
Investigate well performance for		Analysis 1		
Well (Entity)	Forecast	From	To	Calculated on
Gas 1	Analysis 1	9/29/2018	10/28/2018	1/31/2019 8:38:19
Gas 3	Analysis 1	9/29/2018	10/26/2018	1/31/2019 8:38:19
Oil 3	<Forecast Missing>			
Oil 1	<Forecast Missing>			
Oil 2	<Forecast Missing>			
Gas 2	<Forecast Missing>			

Create custom group from selections

Liquid Loading sub-tab

In this sub-tab, you can monitor your forecasts for liquid loading.

Before you can use this sub-tab, you need a model for your wells ([analytical](#) or [numerical](#)) and a forecast of future gas production. For information on theory, see [liquid loading monitor theory](#) and [liquid lift calculations](#).

Note: This feature works with your Harmony Optimize™ license.

Predict liquid loading in the forecast for drop-down list — select an analytical or numerical model with a valid forecast.

Calculate button — click this button to calculate the date of liquid loading for each well (or scenario) in the list. These calculations are saved to the database.

Liquid Loading Date — the time at which the forecasted rate falls below the theoretical liquid loading rate.

Forecast Step — indicates the timestep in the forecast that corresponds to the date of liquid loading.

Gas rate — the predicted gas rate at the time of liquid loading. Note that this is the rate from the model's forecast, not the threshold liquid loading rate.

Diameter — the wellbore diameter used to determine the liquid loading rate.

Productivity — calculated from the forecast data with the following equation:

$$Productivity = \frac{q_g}{\bar{p}_R - p_{wf}}$$

Drawdown — calculated from the forecast data with the following equation:

$$Drawdown = \frac{\bar{p}_R - p_{wf}}{\bar{p}_R} \times 100\%$$

Create custom group from selections — see [grouping wells](#). (This works the same way as the Production vs Forecast sub-tab.)

Note: To copy the full table (all rows) to be pasted into another application, right-click the table and select **Copy Table**, or press **Ctrl-C**.

Column sorting

By default, the earliest date of liquid loading is displayed first. You can sort tabular data by clicking the column headers. The first six columns are frozen, so you can keep track of key information as you scroll horizontally.

Status column

The Status column provides information before and after calculations are performed.

- A red status indicates a calculation problem. Commonly this means that you have not selected a model with a valid forecast. To fix this, you may need to select a model from the drop-down list, or you may need to go to the Analysis tab for that well and create a valid model with a forecast.

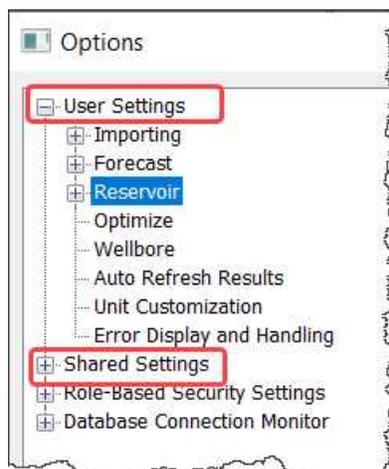
- An orange status indicates that the calculation is either ready to proceed, or it has completed but this well may not be a good candidate for a liquid loading investigation (for example, the wellbore is pumping, or it is on gas lift at the time of liquid loading).
- A blank status indicates there are no issues.

Tip: If you export or import wells with an .hldb file, the data in this tab is not saved. To have this data, you need to recalculate.

Options dialog box

You can access the Options dialog box from the **Tools** menu, or by clicking the **Options** icon (⚙️) on the main toolbar.

Any of the User Settings you change apply after you close the dialog box, and do not affect existing analyses, or other users' analyses. However, Shared Settings are database settings that apply to all entities and other users connected to the database. In some situations, existing analyses are updated as well (for example, BOE and classified consolidations).



Importing

Unreported Volume or Rate

- **Leave as Null (empty)** — assigns no value to volumes / rates whose true value is not reported.

- **Zero** — assigns a value of "0" to volumes / rates whose true value is not reported.
- **Step Interpolate** — carries over the preceding value to an unreported volume. This creates a step-like plot.
- **Linearly Interpolate** — assigns a value to an unreported volume that is equidistant from the preceding and following reported values. This creates a linear plot.

Number Format

Use Comma as Decimal Separator — applies to some European customers where commas are used as a decimal. If this applies to some of your text imports, click to select this option, so that Harmony Enterprise can appropriately handle the numbers.

Import Batch Size

To prevent out-of-memory errors when importing files, you can set your batch size to a fewer number of wells. The default setting is 250 wells (maximum setting) for each of the file types. After you click OK, your settings persist. You do not need to close your database connection in order for your change to take effect.

Import Logging Detail Level

Enable verbose import logging — creates a detailed log after each import, and lists all of the identifiers of incoming wells and which existing well they have linked to (when applicable).

Updating Data

These settings apply globally unless you specify other options on a per-data-source connection basis in the Import Options dialog box.

Production Data

- **Append from last production date** — imports production data from the last production end date.
- **Merge (Overwrite duplicate dates)** — adds new production data and replaces production data for any dates that exist in the current production history.
- **Merge (Do not overwrite duplicate dates)** — adds new production data and keeps production data for any dates that exist in the current production history.
- **Discard all existing data and replace with incoming data** — replaces production data with incoming data.

Attributes and Properties

- **New data only** — imports new attribute and property data and does not overwrite any data.
- **Overwrite / Merge existing data** — adds new attributes and properties, and replaces existing values with newly imported ones.
- **Ignore incoming data** — does not import attribute nor property data.

Analysis Data

These settings only apply when you import well data from a database (Aries), or from PowerTools.

- **New data only** — imports new analyses and does not overwrite any data.
- **Overwrite / Merge existing analyses** — replaces existing analyses when matched with imported ones, and adds new analyses.
- **Ignore incoming data** — does not import analyses.

Wellbore

These settings only apply to Enerdeq, IHDC, .harmony, and .hldb imports:

- **Append with incoming wellbore data** — imports wellbore configurations with dates that occur after the latest configuration for a given well in the Harmony Enterprise project.
- **Discard all existing data and replace with incoming data** — replaces all existing wellbore configurations. Existing configurations are overwritten and new configurations are added to the well. Configuration dates in Harmony Enterprise that are also not in the source data are removed from the Wellbore editor during the import.

Note: When importing deviation surveys, be aware that if the incoming deviation survey is empty, the existing deviation survey is not overwritten by an empty one.

- **Ignore incoming data** — does not import wellbore data.
- **New data only** — the wellbore configurations associated with dates that do not already exist in the Wellbore editor for the well are imported. If the date already exists with an associated configuration, no data is imported.

If importing from Enerdeq or IHDC, only deviation surveys are imported.

- **New data only, Append with incoming wellbore data, and Ignore incoming data Options** — no wellbore data is imported, and existing wellbore data is unchanged.

- **Discard all existing data and replace with incoming data** — only overwrites the deviation survey, *unless* the incoming deviation survey is empty. Existing deviation surveys are not overwritten by null data.

Static Pressures

- **New data only** — imports static pressure data and does not overwrite any data.
- **Discard all existing data and replace with incoming data** — imports all new static pressure data and overwrites data with the same dates as those being imported.

Custom Data

- **Import New Custom Attributes** — if this option is selected, all custom attributes are brought in when importing .hldb or .harmony files. If this option is deselected, values for custom attributes that are already set up in the project are brought in, but no new custom attributes are created on import.
- **Import New Custom Datasets** — if this option is selected, all custom datasets are brought in when importing .hldb or .harmony files. If this option is deselected, values for custom datasets that are already set up in the project are brought in, but no new custom datasets are created on import.

Autocalc Settings

By default, sandface pressure calculations are calculated after your scenarios are imported because this can be a time-consuming process.

- **Do Sandface pressure calculation after importing on wells** — if selected, sandface pressure calculations are done after your wells are imported. If deselected, sandface pressure calculations are not done.
- **Do Sandface pressure calculation after importing on scenarios** — if selected (default setting), sandface pressure calculations are done after your scenarios are imported. If deselected, sandface pressure calculations are not done.

You can select both of these options in which case, sandface calculations are done after both the wells and scenarios are imported. If both options are deselected, sandface calculations are not performed.

Data Reduction

Data Reduction Filter

- **Always Display the Data Reduction Dialog** — opens the [Data Reduction dialog box](#) every time well data is imported into the project.
- **Display the Data Reduction Dialog when threshold is reached** — opens the Data Reduction dialog box only when an incoming well has more than the specified threshold number of production rows.

Data Reduction Thresholds

- **Threshold** — the number of rows of production data in a well that causes the Data Reduction dialog box to open.
- **Gas Rates** — the number below which gas values are treated as shut-in when automatically detecting flowing / shut-in periods in data reduction.
- **Liquid Rates** — the number below which liquid values are treated as shut-in when automatically detecting flowing / shut-in periods in data reduction.

Data Reduction Filter Defaults

- **Arithmetic Filter** — the default value for all periods using the arithmetic filter.
- **Log Filter** — the default value for all periods using the log filter.

Data Reduction Use in Period Defaults

- **Flowing Periods** — sets flowing period defaults to the filter values specified in the Data Reduction Filter Defaults section.
- **Shut-In Periods** — sets shut-in period defaults to the filter values specified in the Data Reduction Filter Defaults section.

Well Linking

By selecting from the **Import Format** drop-down list, you can view the entity header attributes (listed in the [Attributes tab](#)) that are used to link incoming data to existing wells. For information on how Harmony Enterprise updates wells and merges incoming well data to existing wells, see [well linking logic](#).

The default Entity Header attributes used for well linking are listed by Import Format type. For each Import Format type, attributes are listed in order of linking priority. Most import formats do not allow you to edit linking criteria. However, you can edit the linking criteria for Harmony files, Database Connections, and Text-type files.

To exclude attributes from the linking process, deselect their checkboxes. To include attributes, select their checkboxes. To change the order of priority, click the attribute you want to change, and then click the **Move Up** or **Move Down** buttons. As these changes are saved locally, in order

to share your settings, you need to click the **Export Criteria** button when you are finished with your changes. You can then share the .wlc file with other colleagues.

You can import an .wlc file by clicking the **Import Criteria** button (similar to sharing a template). To go back to the original settings for the import format you have currently selected, click the **Reset to Default** button.

Enerdeq / IHDC

These options determine the behavior of the direct connection to IHS Markit.

IHS Enerdeq Direct Connection:

- **Save Login Information** — saves your username and password, so you can log into Enerdeq USA without manually entering your login credentials.
- **Split Enerdeq Wells by Production ID** — when importing wells, you can separate wells based on production ID. For example, this may apply when you are importing US data where the production IDs have changed throughout the life of a well. In Harmony Enterprise, there is one well per API, and production history from individual production IDs are aggregated together to make sure that the whole production history is captured.
- **Aggregate overlapping data in multiple Production IDs** — when an API has multiple production IDs, there can be overlapping production periods between production IDs. Select this option to aggregate production data during periods of overlap. The default Enerdeq import behavior concatenates production data from multiple production IDs, and treats any overlap as duplicate production (duplicate dates are not imported).

Import Oil / Condensate data for Enerdeq and .98c files:

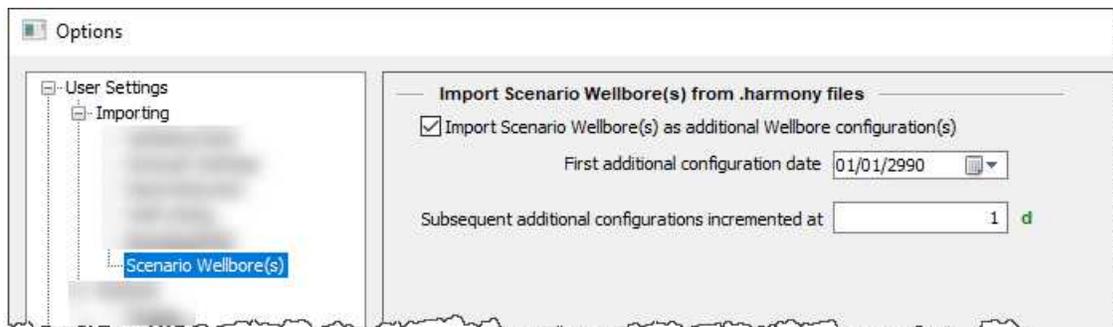
- **Import as identified** — oil and condensate are imported in the same way as they are identified in the source.
- **Import as Oil** — condensate is imported as oil unless there is already oil reported in the same period. Oil is still imported as oil.
- **Import as Condensate** — oil is imported as condensate unless there is already condensate reported in the same period. Condensate is still imported as condensate.

IHS Information Hub Direct Connection (IHDC):

- **Save Login Information** — saves your username and password, so you can log into IHDC without manually entering your login credentials.

Scenario Wellbore(s)

Wells in .harmony files may have several scenario wellbores in addition to a Physical Wellbore.



When importing such files to Harmony Enterprise, you can bring Scenario Wellbores as additional wellbore configurations for the well they belong to. Configurations need to have dates assigned to them, so you can set the date for the first additional configuration, and the subsequent configurations are set at the dates that are incremented after this first date.

Note: We recommend assigning Scenario Wellbore dates that are far in the future, so that these additional configurations do not affect wellbore calculations during production history and wellhead forecasts.

Forecast

To automatically add the Add Analysis menu to a new worksheet, click the Worksheet Creation checkbox (default setting).

Decline

These options set the initialization of new decline analyses and constrain the use of best-fit tools:

You can set the parameters that initialize all decline analyses in Harmony Enterprise, and you can change these initialization values while performing an analysis (within the analysis worksheet).

The decline parameters and settings are as follows:

- **Show results line** — displays / hides a green-dashed line at:
 - i.) the final segment abandonment rate
 - ii.) the point where a segment transitions from hyperbolic to exponential (if applicable).

- **b Value (initialization)** — select either **Best Fit** or **Fixed b**.
 - **Min and Max** — sets the minimum and maximum b value allowed for the best-fit decline. Harmony Enterprise accepts any value between 0 and 5.
 - **Enable b value minimization** — when you add a decline analysis, Harmony Enterprise automatically selects the best subset of your data for an initial best fit. When this option is selected, the b value (slope) is minimized without sacrificing the quality of the fit. This can be of particular use with unconventional reservoirs where there is more curvature in the declines. (This option is deselected by default.)
 - **Fixed b** — if this option is selected, you must type a b value for every decline to initialize on. (The yellow lock icon defaults to a locked  position.) Harmony Enterprise accepts any value between 0 and 5.
- **d (at Forecast Start Date)** — sets an effective decline rate from the forecast start date of a segment, so that each new decline curve initializes with this value. This parameter can be toggled among the effective decline rates (*d sec and d tan*), or the initial nominal decline rate (*a*). When the decline is created, whichever of the three parameters displayed is the default rate type displayed in the Analysis Parameters.
- **d_{lim} (Minimum / Limiting Decline Rate)** — defines a limiting effective decline rate, and every decline switches to an exponential decline (*b=0*) when this value is reached. The default setting is 8%. This parameter can be toggled from *d_{lim} Hyp* to *d_{lim} Exp*. When the decline is created, whichever of the two parameters displayed is the default *d_{lim}* type shown in the Analysis Parameters.
- **Initial Best Fit** — select either **Autoforecast** or **Last X% of data points**
 - **Autoforecast** — (default setting) an automatic rigorous fit of an Arps' decline. This initial best fit identifies the partition to fit to, and excludes outliers before fitting the data.
 - **Last X% of data points** — uses the last-specified percentage of the data to initialize the analyses.
- **Abandonment Criteria** — defines the abandonment rates (*q_f*) for different fluids, or the duration of the decline (Δt) as abandonment criteria.
- **Default Calc Method** — defines the Calculation Method to be used for the initialization of a decline. The options in the drop-down list depend on whether there is a value for the *d_{lim} Hyp* or *d_{lim} Exp*. When there is a value in either of these fields, the drop-down list only contains calculation methods that use *d_{lim}*. When there are no values in either of these fields, all the

calculation methods (including those with d_{lim}) are displayed in the drop-down list.

Probabilistic Decline

These options set the initialization of new probabilistic decline (beta) analyses.

You can set the parameters that initialize all decline analyses in Harmony Enterprise, and you can change these initialization values while performing an analysis (within the analysis worksheet).

The decline parameters and settings are as follows:

- **Initial Best Fit** — select either **Autoforecast** or **Last X% of data points**
 - **Autoforecast** — (default setting) an automatic rigorous fit of an Arps' decline. This initial best fit identifies the partition to fit to, and excludes outliers before fitting the data.
 - **Last X% of data points** — uses the last-specified percentage of the data to initialize the analyses.
- **Plot Defaults | Show results line** — displays / hides a green-dashed line at:
 - i.) the final segment abandonment rate
 - ii.) the point where a segment transitions from hyperbolic to exponential (if applicable).
- **b Value Range** — sets the minimum and maximum b value used in the forecast distribution used to determine percentiles. Harmony Enterprise accepts any value between 0 and 5.
- **d_{lim} (Minimum / Limiting Decline Rate)** — defines a limiting effective decline rate, and every decline switches to an exponential decline ($b=0$) when this value is reached. This parameter can be toggled from d_{lim} Hyp to d_{lim} Exp. When the decline is created, whichever of the two parameters displayed is the default d_{lim} type is displayed in the Analysis Parameters pane.
- **Percentiles** — add and remove percentiles to change which forecasts are created with the probabilistic decline. When a row is selected, you can click the percentile value or analysis name to modify them. The table must have at least two percentiles, and the Remove button is disabled when there are only two rows in the table.
- **Default Calc Method** — defines the Calculation Method to be used for the initialization of a decline. The options in the drop-down list depend on whether there is a value for the d_{lim} Hyp or d_{lim} Exp. When there is a value in either of these fields, the drop-down list only contains calculation methods that use d_{lim} . When there are no values in either of these fields, all the calculation methods (including those with d_{lim}) are displayed in the drop-down list.

- **Abandonment Criteria** — defines the abandonment rates (q_f) for different fluids, or the duration of the decline (Δt) as abandonment criteria.

Multi Segment Decline

You can set the parameters that initialize all multi-segment decline analyses in Harmony Enterprise, and you can change these initialization values while performing the analysis, within the analysis worksheet. The multi-segment decline parameters and settings are as follows:

Gas Defaults

Segment #1:

- **b value** — select your *b* type for the *first segment* from the drop-down list: *Best Fit*, *Input*, or *Custom*.
 - **Input** — enter your *b* value between 0 and 5 inclusively.
 - **Best Fit** — Harmony Enterprise performs a curve-fitting to the selected historical portion of the data and reports a *b* value.
 - **Custom** — if you have already created a custom attribute for *b* values, you can select *Custom* from the *b* drop-down list. (The custom attribute must be without units.)
- **Constraints** — you can define up to four constraints for the *first segment*. Harmony Enterprise needs at least one constraint within this section. If you define multiple constraints, the first constraint that is chronologically encountered, is the constraint that is applied.
 - You can select your Δt_{\max} to be an *Input* or *Custom* value from the drop-down list. A default value of 12 months is used. If you select a custom attribute for your Δt_{\max} , make sure that the attribute has a unit of time. All attributes that have a time unit are displayed in the *Custom* drop-down list.
 - You can also set your constraints to be a minimum production rate (q_{\min}), minimum effective decline rate (d_{\min}), and/or maximum incremental cumulative production (ΔQ_{\max}).

Segment #2:

- **b value** — you can define *b*-value settings for the *second segment*, similar to Segment #1 (see above).
- **d_{\lim} Exp** — click this button to toggle between *exponential d_{\lim}* and *hyperbolic d_{\lim}* . For more information, see [d_{lim} decline options](#). If there is no value in the $d_{\lim, \text{exp}}$ field, a limiting decline calculation is not performed on the *second seg-*

ment. If you toggle this option, any values you enter are saved, and the current selection is what is used.

Liquid Defaults

See the Gas Defaults section above.

Best-Fit criteria

For your *first segment*, you can select to start at either:

- **from initial peak rate** (default setting) — equivalent to the highest rate that the entity has produced throughout its entire history.
- **from initial production** — the first production data point for that entity.

Typewell

These settings apply to the average rate, P90 rate, P50 rate, P10 rate, and the number of producing wells. For additional information, see the [typewell analysis](#).

- **All Rates** — includes all wells in your rate calculations
- **Producing Rates Only** — only includes producing wells in your calculations

Material Balance

These options affect the behavior of material balance analyses:

- **Show abandonment line** — shows / hides the abandonment line on your plot.
- **Abandonment Pressure** — sets which “Abd Calc” method (in the Analysis Parameters view of the Analysis tab) is used by default when an analysis is created.

Water Oil Ratio

You can set the parameters that initialize water-oil ratio (WOR) analyses in Harmony Enterprise. These inputs can be overridden with each analysis, and the Options dialog box inputs are only used when the analysis is created. The WOR parameters and settings are as follows:

- **Show results line** — shows / hides the green-dashed line for abandonment on your plot.
- **WOR** — sets the abandonment WOR. Harmony Enterprise uses 49 bbl/stb as the default.

- **WC** — sets the abandonment water cut (WC). Harmony Enterprise uses 98% as the default.
- **Initial Best Fit** — specifies the percentage of your historical data that you want to be included in the initial best fit.

Reservoir

URM

Display Pseudo-Time Option — if selected, the **Use Corrected Pseudo-Time checkbox** is shown in the Unconventional Reservoir pane. The default setting is to hide this option.

Numerical

Gridding Parameter Defaults

Type your default gridding parameters for new analyses. For a detailed explanation of each of the parameters, see adjusting gridding.

If you want to revert to the original parameters, click the **Reset to Default** button at the bottom.

Wellhead Forecast

In some cases, wellhead forecasts have unstable results: well shut-ins and re-opens multiple times. Click the **Apply TPC Curve Stabilization** checkbox to switch to sandface forecasts during these unstable periods. For more information, see TPC stabilization.

Conventional Multi-well

Type your default gridding parameters for new analyses. For a detailed explanation of each of the parameters, see gridding parameters.

If you want to revert to the original parameters, click the **Reset to Default** button at the bottom.

Unconventional Multi-well

Type your default gridding parameters for new analyses. For a detailed explanation of each of the parameters, see gridding parameters.

If you want to revert to the original parameters, click the **Reset to Default** button at the bottom.

Probabilistic

Set your maximum number of threads for processing [probabilistic analyses](#).

Optimize

Type your default setting for an erosion constant, and select your default H₂S release rate. For more information, see [Optimize analysis types](#).

Wellbore

Select either **Configuration Name** or **Configuration Data** for the default setting in the [Wellbore editor](#) and [Optimize worksheets](#).

For information on importing and updating wellbore information, see [Importing | Updating wellbore](#).

Auto Refresh Results

Set up your automated scheduled recalculations for [FMB](#) and [URM](#) analyses by selecting from the list of Custom Groups. For detailed instructions, see [scheduling auto refresh results](#).

Unit Customization

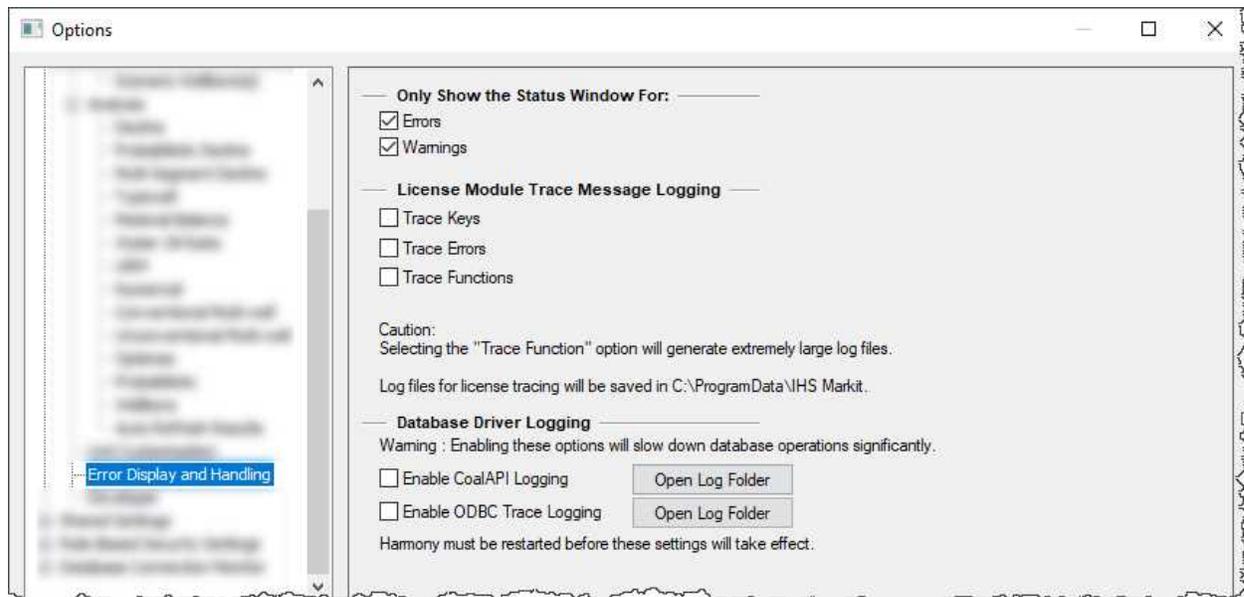
For each of the attributes and properties listed in the main pane, you can set default units by selecting from the drop-down lists.

To import customized units in a .cu file, click the **Import** button.

To export customized units, click the **Export** button.

If you want to revert back to the original default settings, click the **Reset** button.

Error Display and Handling



Only Show the Status Window For — click the checkboxes to show or hide error messages and warnings in the Status Window. By default, errors and warnings are displayed in the Status Window.

License Module Trace Message Logging — to enable logging for the license module, click the options you want. Note that these trace log files are extremely large. The log file directory is C:\ProgramData\IHS Markit.

Database Driver Logging — if you are importing data from a source database and receiving error messages related to that connection, or failure messages from the source database, you can enable database driver logging to capture detailed information to help find a solution. Your database administrator (DBA) can use these logs to isolate the issue and work on a solution. Database drivers are created and set up in the Microsoft ODBC Data Source Administrator, and often require elevated permissions, credentials, schema or views, and proprietary server and port information. Database driver logging provides information specific to your source database and connection, which could potentially include confidential or proprietary information.

You must restart Harmony Enterprise before CoalAPI and/or ODBC Trace logging changes take effect. Due to the nature of these logs, performance related to database operations slows down significantly, including imports. We recommend disabling these logs when you finish troubleshooting.

- **CoalAPI Logging** — uses a registry-based setting on the host computer, which is then used to trace events related to database connections. If you are importing from a source database and receiving error messages that cannot be interpreted, click the checkbox to enable this feature. Then, restart Harmony Enterprise and try connecting to the source database again. A log file is created in the listed directory.
Important: After generating the CoalAPI Trace log, disable this feature and restart Harmony Enterprise to prevent slow performance. We recommend providing your DBA with the log files for assistance.
- **ODBC Trace Logging** — uses the Microsoft ODBC Data Source Administrator Tracing tool. If you are importing from a source database and receiving error messages, click the checkbox to enable this feature. Then, restart Harmony Enterprise and try connecting to the source database again. A log file is created in the listed directory. Note that ODBC trace logs may be several megabytes in size, and Notepad may not be able to open them. Alternatives include Notepad++, Visual Studio, or SQL Server Management Studio.
Important: After generating the ODBC Trace log, disable this feature and restart Harmony Enterprise to prevent slow performance. We recommend providing your DBA with the log files for assistance.

Important: The log files generated from CoalAPI and ODBC trace logging may contain proprietary information (for example, server names, well or analysis information, etc.). We recommend you consider the content of these files before sharing with others.

Shared Settings

These settings are database settings that apply to all entities.

General

Display Name Format — set your display name format (that is, DLS, NTS, API, Name, Number, Alias, Propnum, or External Well Key) from the drop-down list for all new wells (imported or added manually).

Calculations

Gas Conversion to BOE — barrel of oil equivalent (BOE) = oil volume + gas volume / factor. This factor can be changed from the default value of six, but the factor must be greater than one.

Classified Consolidations — select this option to include fluid produced from all wells, if you want to consolidate classified and unclassified decline analyses at the group level for EUR and fluid-produced calculations. The default setting only includes classified decline analyses. After you click OK, all consolidations are adjusted, which may take several minutes.

Production Editor Injection Sandface Calculations — select this option to enable injection rates when performing sandface pressure calculations in the [Production editor](#). For more information, see [injection calculations](#). By default, this option is deselected. This default setting ignores injection rates, and thereby uses the same logic as legacy versions of Harmony Enterprise.

Analytics Explorer — forecasts are stored as monthly increments for export to Analytics Explorer. Decline analyses and ratio trends can be saved as daily data for the start of forecast by setting a number of months to be converted to daily. Because of the large amount of data and performance impacts on the export, this is limited to a maximum of 12 months. The option is used the next time decline analyses are saved. The Refresh option in the Entity Viewer's context menu can be used to update selected wells. For more information, see [context menu](#).

Role-Based Security Settings

These options apply to [role-based security](#). If any of these settings are grayed-out, you do not have permission to make changes in this area.

Enable / Disable

Role-based security checkbox — by clicking this checkbox, you can assign permissions to other users for certain Harmony Enterprise tasks. In order for any changes to take effect, you need to close Harmony Enterprise and re-open it.

Role Definitions

The Superuser and Default roles are always available and cannot be edited nor deleted.

Roles:

- **Add** — clicking this button creates a new role (by default, Role 1, Role 2, and so on). You can rename a role (*excluding* the Superuser and Default roles) by clicking the role and typing a new name.
- **Remove** — after selecting a role and clicking this button, the role is deleted from the Roles pane.

Note: These buttons are only accessible to Superusers and users that have permission to manage security.

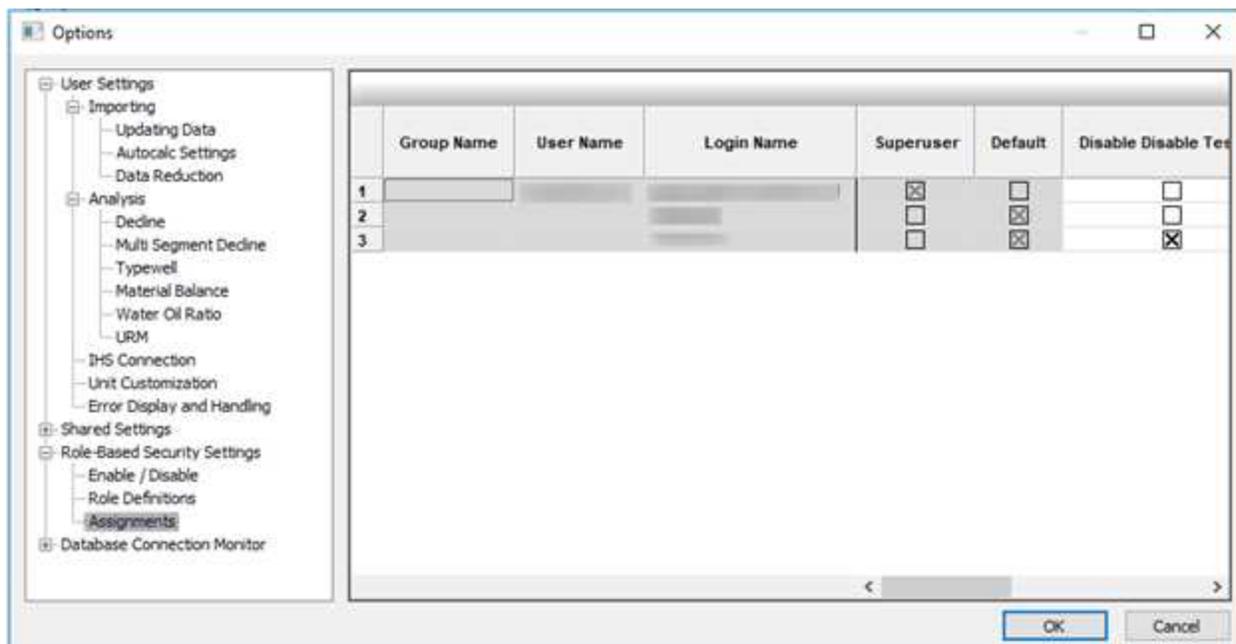
Permissions:

- **Manage Security** — if you select this option, the role selected in the Roles pane can edit permissions for other users (excluding the Superuser and Default users).

- **Import / Update Wells** — if you select this option, the role selected in the Roles pane can import and update wells.
- **Delete Wells** — if you select this option, the role selected in the Roles pane can delete wells in the Entity Viewer - Hierarchy pane, and scenarios can be deleted even when that permission is not explicitly selected.
- **Delete Scenarios** — if you select this option, the role selected in the Roles pane can delete scenarios under wells in the Entity Viewer – Hierarchy pane without requiring permission to delete wells.
- **Modify Editors** — if you select this option, the role selected in the Roles pane can change data in the Editors (that is, Properties, Wellbore, Production, Static Pressure). Note that when Modify Editors is not granted and Import / Update wells is granted, only the Database Connection is available for import. Also note that you are still able to change data in the Editors on a scenario without having this permission. However, you are not able to promote a scenario to become the parent well.
- **Modify Existing Database Connections** — if you select this option, the role selected in the Roles pane can change the mapping and other settings of an existing Database Connection used for imports.
- **Extract to HLDB** — if you select this option, the role selected in the Roles pane can extract wells, scenarios, and groups to an .hldb file.

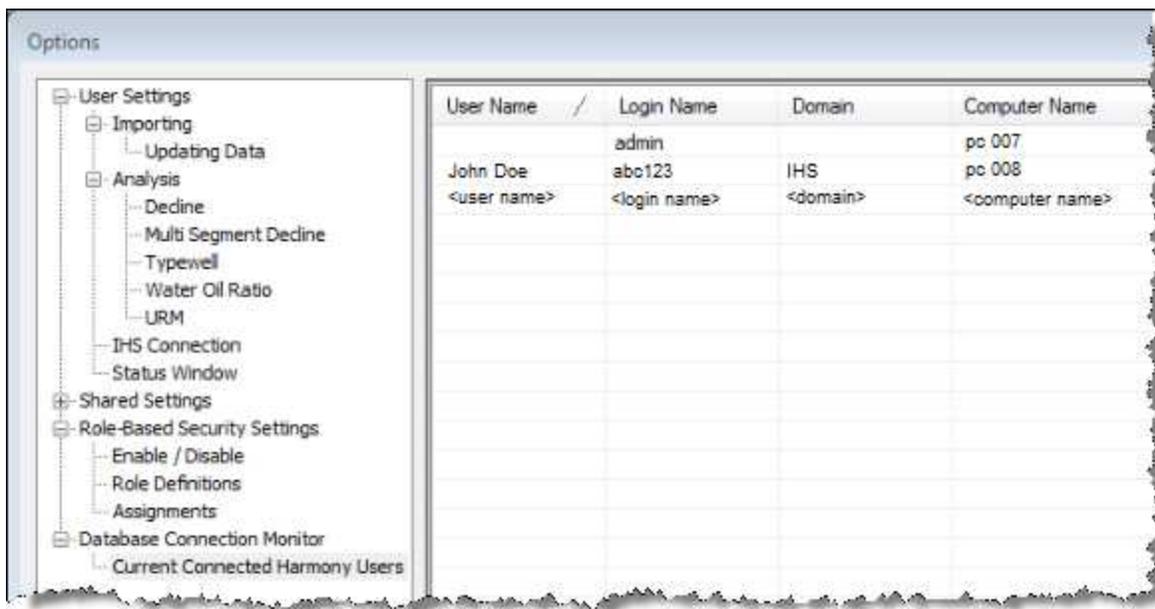
Assignments

You can assign roles to various users by clicking the appropriate checkboxes in the table.



Database Connection Monitor

This table displays all the currently connected users to Harmony Enterprise.



If the **View server state** checkbox is deselected in SQL Server Management Server, you are not able to see this content. If this is an issue, contact your database administrator. For more information, see [active directory](#).

Piper export

Piper export functionality includes the following:

- [Export Type dialog box](#)
- [Analyses Selection dialog box](#)
- [Well-Analysis Pairing Conflicts dialog box](#)
- [Export logs](#)

Export Type dialog box

This dialog box opens when you access the [Piper Export wizard](#) (after the Welcome dialog box). In this dialog box, you select the type of export, and the file name and path for the file you want to export.

Important: Calibration must be done prior to forecasting.

Type of export

Select from these two options:

1. **Building and Calibration** — exports well locations, fluid properties, wellbore, rates, and pressures for each well as of the effective date. This information is used to calibrate your selected wells.

Effective Date — if you have production up to the current month, the default date is midnight on the first day of the current month. Click the date and time fields to select the appropriate snapshot in time for your measured rates and pressures.

Tip: When selecting an effective date, it may be helpful to view the [Diagnostic tab](#).

There are four reasons to select this option:

- a. to build a new model
- b. to add new wells to an existing model

- c. to create conventional deliverability typewells in Piper (e.g., Gas: wellhead test, wellhead c&n, sandface c&n, Gas and oil wells: fixed rate or profile)
 - d. to validate a Piper model (also known as calibration)
2. **Forecasting** — exports well locations and other attributes together with one analytical model per well. This information is used to predict future production.

File name and path

Browse to the appropriate location for your text file to be saved. After you complete the steps in the wizard, you can import this file into Piper®.

Note: If you run the wizard again with the same filename, wells with the same name are overwritten.

Analyses Selection dialog box

This dialog box is part of the Piper Export wizard. In this dialog box, you select your analyses for export, and you are given the option of exporting wells without analyses.

Note: You must select at least one analysis in order to proceed, or you can include wells without analyses.

Analyses for the wells you want to export are displayed by analysis type. You can export well locations and other attributes together with one analytical model per well.

Select one analysis for each well you want to export.

If you want to export wells that are not paired with an analysis, click the checkbox in the lower left. Note that your wells are exported without rate and pressure data.

Well-Analysis Pairing Conflicts dialog box

This dialog box is part of the Piper Export wizard and it only appears when there is more than one analysis paired with a well. In this dialog box, you resolve any conflicts by selecting from the Select Analysis drop-down list.

Note: You must resolve all conflicts in order to proceed.

Any wells that have more than one analysis assigned to them are listed in the Well column.

Select Analysis drop-down list — select either:

- **Exclude from Export** — excludes the well from the export
- **<Analysis name>** — pairs your selected analytical analysis with the well

Piper export logs

You can view these logs by clicking the link in the [Piper Export | Summary](#), or by browsing to your export data file.

Calibration data

An example Calibration data log is shown below.

Piper Export initiated at Wednesday, September 12, 2018, 11:28:03

Wells exported successfully:

- With analyses: 0
- With well data only: 15

Corrections performed during export:

- Sandface pressure recalculations: 0
- Flow path corrections: 1

Details of modified or failed wells:

- Well 4 wellbore has been modified from unsupported casing flow path to tubing flow path.

Forecast data

An example Forecast data log is shown below.

Piper Export initiated at Wednesday, September 12, 2018, 12:01:00

Wells exported successfully:

- With analyses: 15
- With well data only: 0

Corrections performed during export:

- Sandface pressure recalculations: 9

- Flow path corrections: 1

Details of modified or failed wells:

- Well 1 has been modified with its sandface pressure recalculated.

- Well 2 wellbore has been modified from unsupported casing flow path to tubing flow path.

- Well 2 has been modified with its sandface pressure recalculated.

- Well 3 has been modified with its sandface pressure recalculated.

- Well 4 has been modified with its sandface pressure recalculated.

- Well 5 has been modified with its sandface pressure recalculated.

- Well 6 has been modified with its sandface pressure recalculated.

- Well 7 has been modified with its sandface pressure recalculated.

- Well 8 has been modified with its sandface pressure recalculated.

- Well 9 has been modified with its sandface pressure recalculated.

Plots

Plots are a vital tool used in analyzing well data, comparing data (see [comparison plot](#)), and are displayed in many different areas in Harmony Enterprise.

These items apply to plots:

- [Plot components](#)
- [Plot types](#)
- [Diagnostic line](#)

Plot components

Plot components include locks, a legend, and context menus. For information on toolbars, see [plot toolbars](#).

Locks

Each axis has a lock at both ends to control resizing and movement. Locks are represented by two different icons, depending on their state:

Icon	Status	Description
	Unlocked	This end of the axis is free to move or change in scale.
	Locked	This end of the axis is locked down (that is, immobile).

Locks can be toggled independently by clicking them. The state of these locks affects the behavior of the axis when you click-and-drag. The possible lock states and their effects on the axis are described below:

Lock States	Effect on Axis
	Both ends are free to move; dragging the axis pans / slides without changing in scale.
	Neither side of the axis can move; dragging the axis zooms in.
 or 	The end that is unlocked stretches or shrinks, rescaling the axis.

Legend

The legend displays the relevant datasets on the plot. To show or hide a legend on any plot: right-click the plot and select **Show Legend** or **Hide Legend**.

- Single-well plot legends display the available datasets for the selected well.
- Multi-well plot legends display the individual wells as differently colored lines.

Plot context menus

Plots have two sets of context menus.

Axis options

Right-clicking an axis lists these options:

- **Autoscale Axis** — scales the axis to fit the data.
- **Change Axis Units** — select your units from the submenu.
- **Sync - Snap - Square** — links up major axis lines between multiple axis scales.
- **Customize Axis** — select your axis preferences (labels, font settings, and so on) in the Axis dialog box.
- **Move Axis to Right / Left Side** — moves the axis to the other side of the plot.
- **Link / Unlink Axes** — connects axes of different datasets to share a common scale (must be the same units), or disconnects them.
- **Major Grid Lines** — shows / hides major grid lines.
- **Minor Grid Lines** — shows / hides minor grid lines.
- **Snap Scale** — snaps the axis to the closest major grid line division / whole number.
- **Sync all log axes to use 1 log cycles** — synchronizes log axes to 1-log cycles.
- **Show / Hide Toolbar** — shows / hides the tab's toolbar.

Plot options

Right-clicking a plot lists these options:

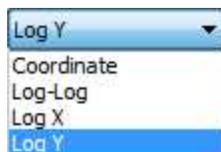
- **Send Dataset to Comparison Plot** — opens a snapshot of your dataset in a new or existing comparison plot. (You must right-click a specific dataset.)
- **Copy / Paste Dataset** — copy and paste your dataset content. For example, you can copy your dataset to the comparison plot as an independent dataset, which retains the customizations you set up (name, line / symbol properties, axis titles, and so on). (You must right-click a specific dataset.)
- **Customize Datasets** — change the display order, and / or customize the display for specific datasets.
- **Customize Plot** — select your plot preferences in the Plot dialog box.
- **Customize Axis** — select your axis preferences in the Axis dialog box.
- **Customize Main Title** — type or select attributes for your title and subtitle in the Titles dialog box.

- **Customize Left Header** — type or select attributes for your left-header information in the Left Header dialog box.
- **Customize Right Header** — type or select attributes for your right-header information in the Right Header dialog box.
- **Show / Hide Legend** — shows / hides the legend.
- **Customize Legend** — select your legend preferences in the Legend dialog box.
- **Copy / Paste Plot** — copy and paste your plot content. For example, you can copy your plot to the comparison plot.
- **Send Plot to Comparison Plot** — opens a snapshot of your plot in a new or existing comparison plot.
- **Show / Hide Toolbar** — shows / hides the tab's toolbar.

Plot types

There are different types of plots in Harmony Enterprise, and often the plots that are available for viewing depend on the datasets currently displayed.

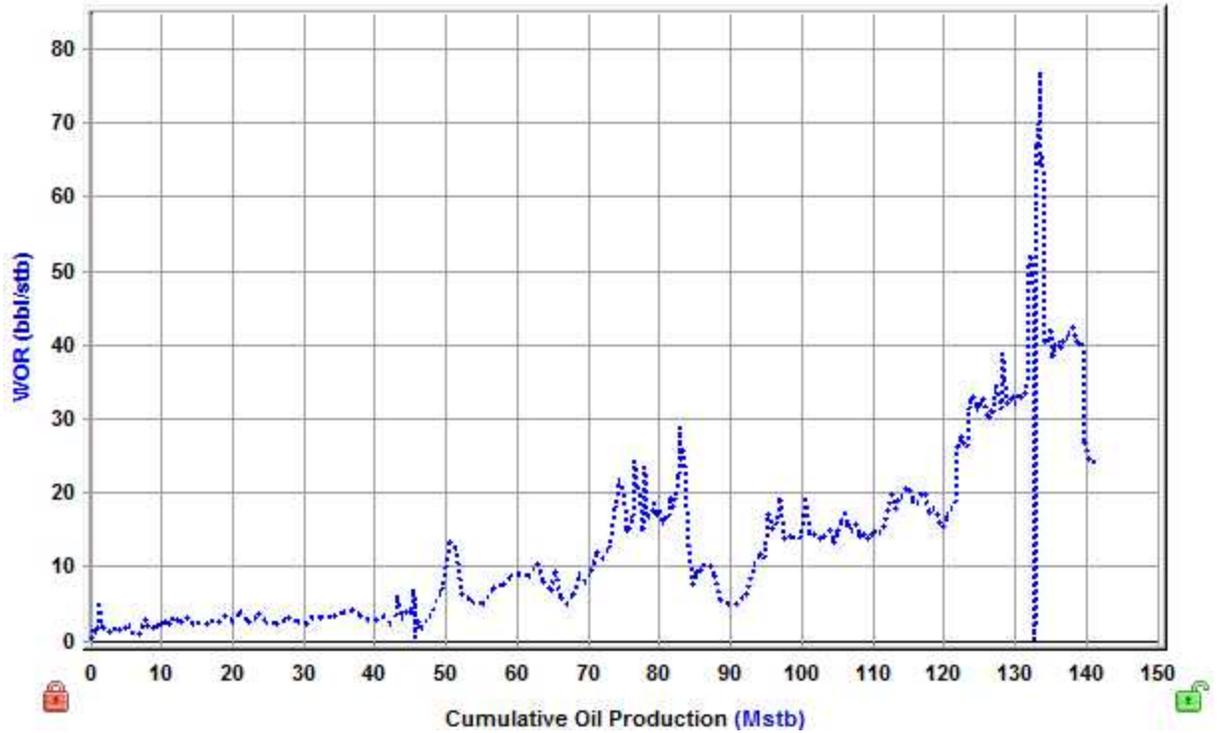
For example, you can select a plot type from the drop-down menu in the Diagnostics tab:



Coordinate plots

Coordinate (also called 'Cartesian') plots display data in a 1:1 ratio with no manipulation of the axes.

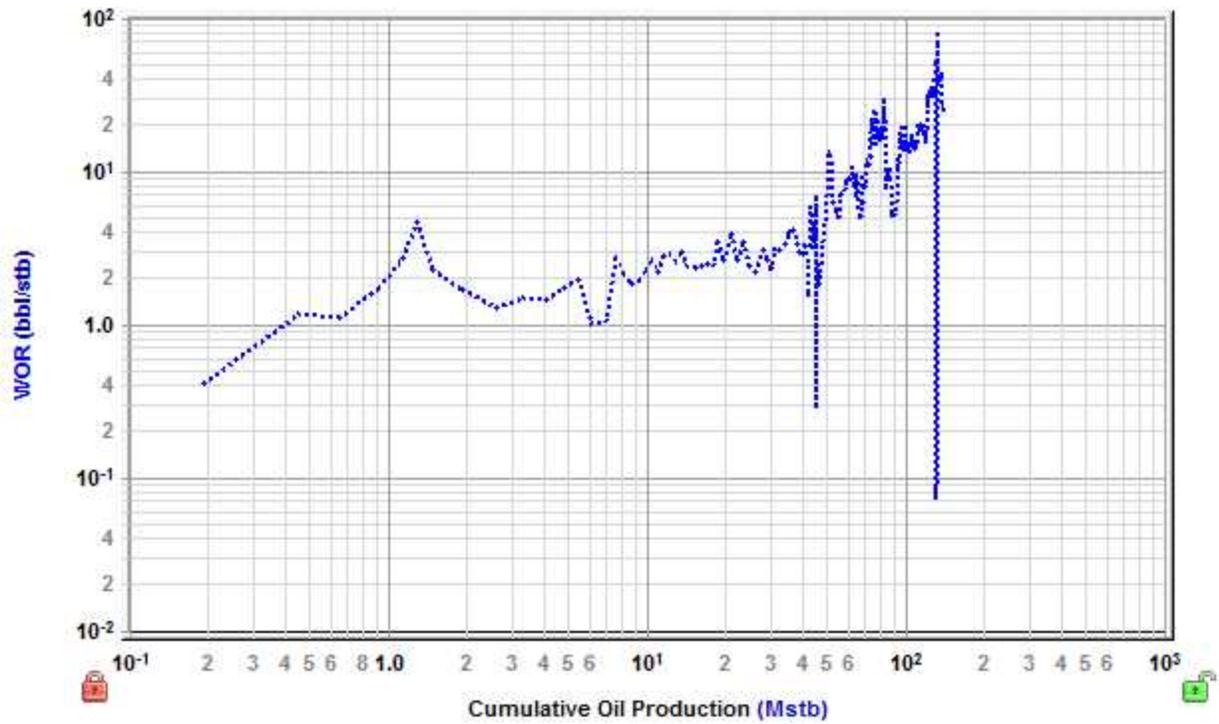
An example of a coordinate plot:



Log-log plots

Log-log plots use logarithmic scales on the x- and y-axes to stretch data in order to view trends in the data that are not apparent with Cartesian coordinates.

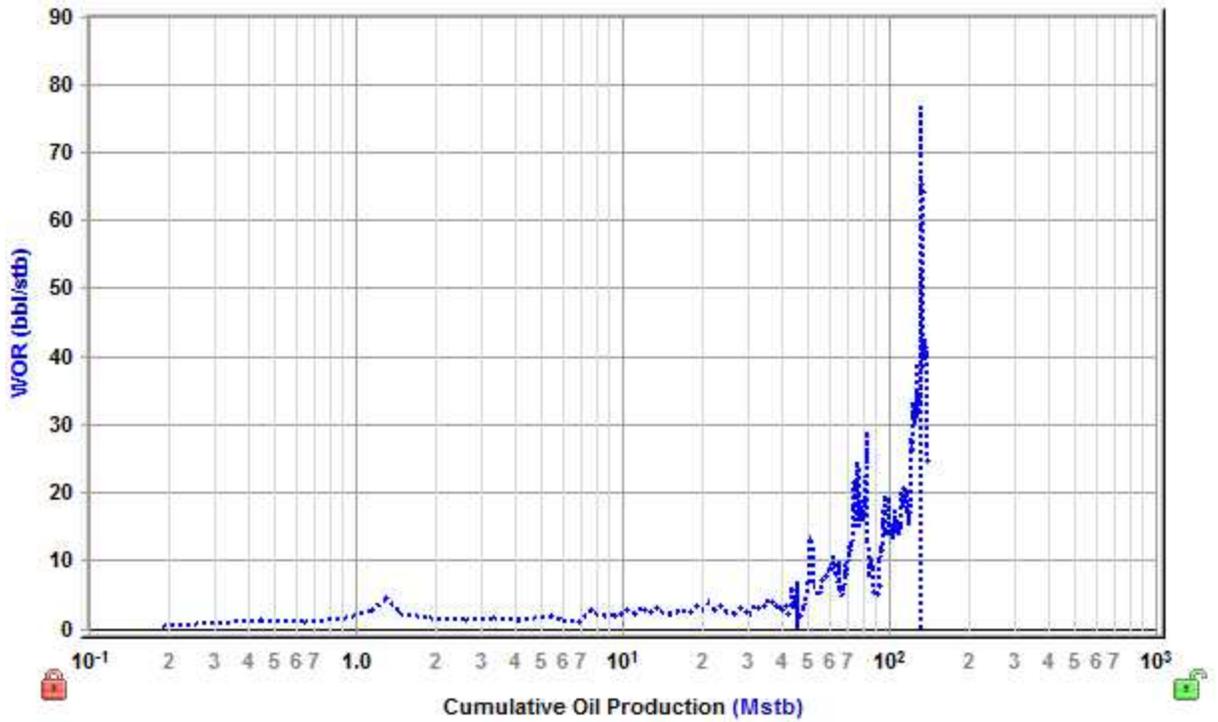
An example of a log-log plot:



Log-X plots

In log-X plots, the scale of the x axis increases exponentially. Manipulating the y-axis in this way places emphasis on a specific portion of the data set (for example, semi-log time emphasizes early-time data).

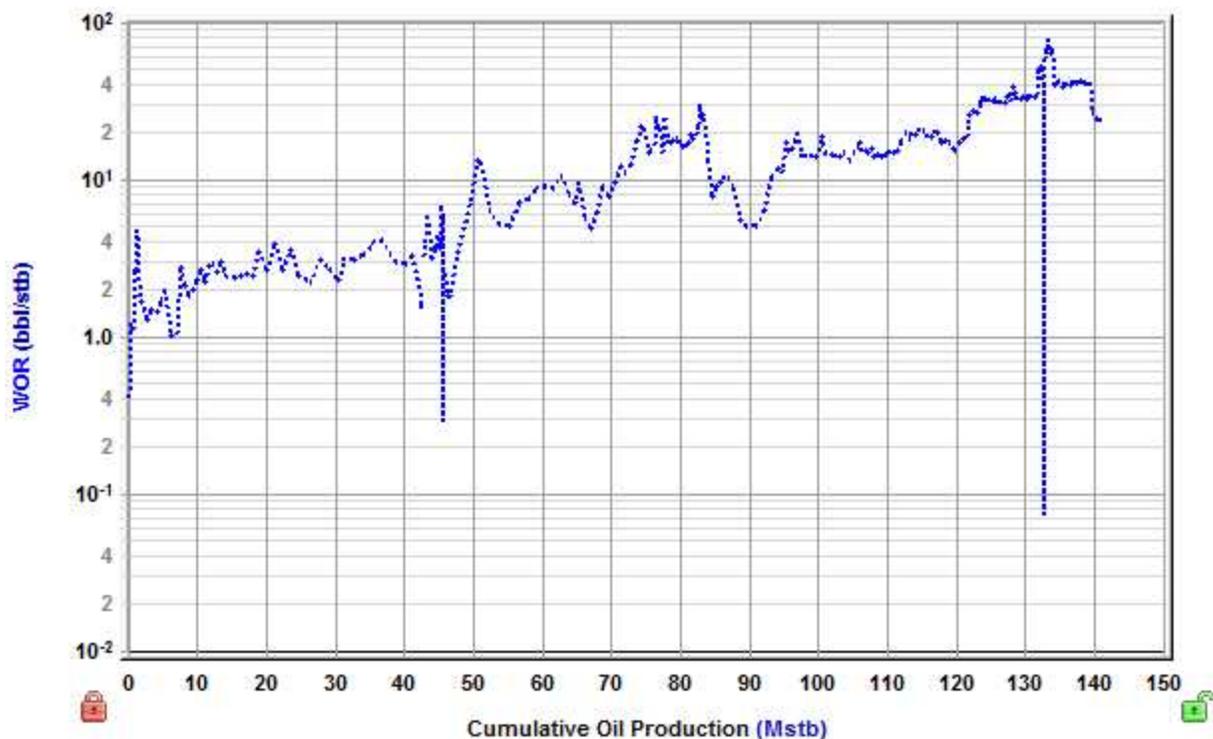
An example of a log-X plot:



Log-Y plots

In log-Y plots, the scale of the y-axis increases exponentially. Manipulating the x-axis in this way normalizes a large range of data that is difficult or impossible to analyze on a coordinate plot.

An example of a log-Y plot:

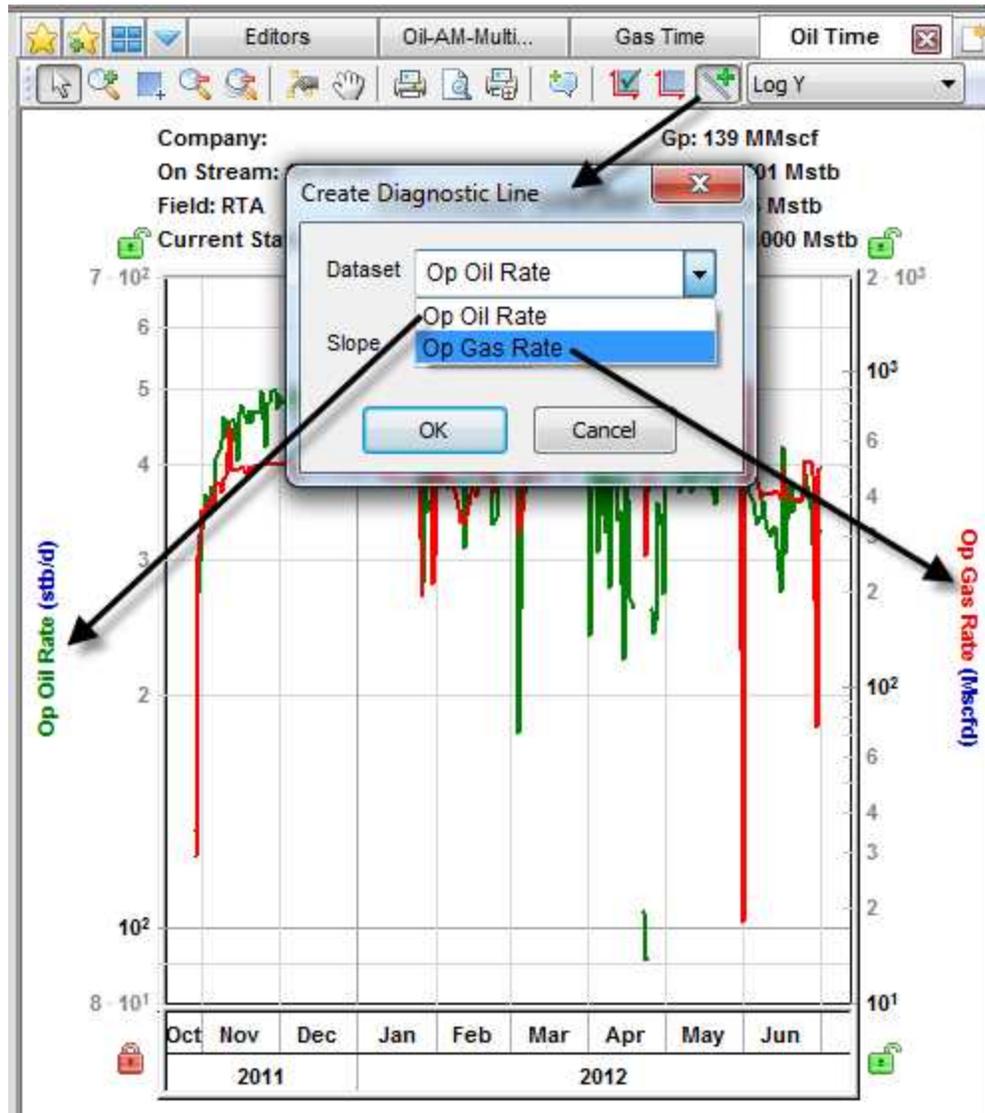


Diagnostic line

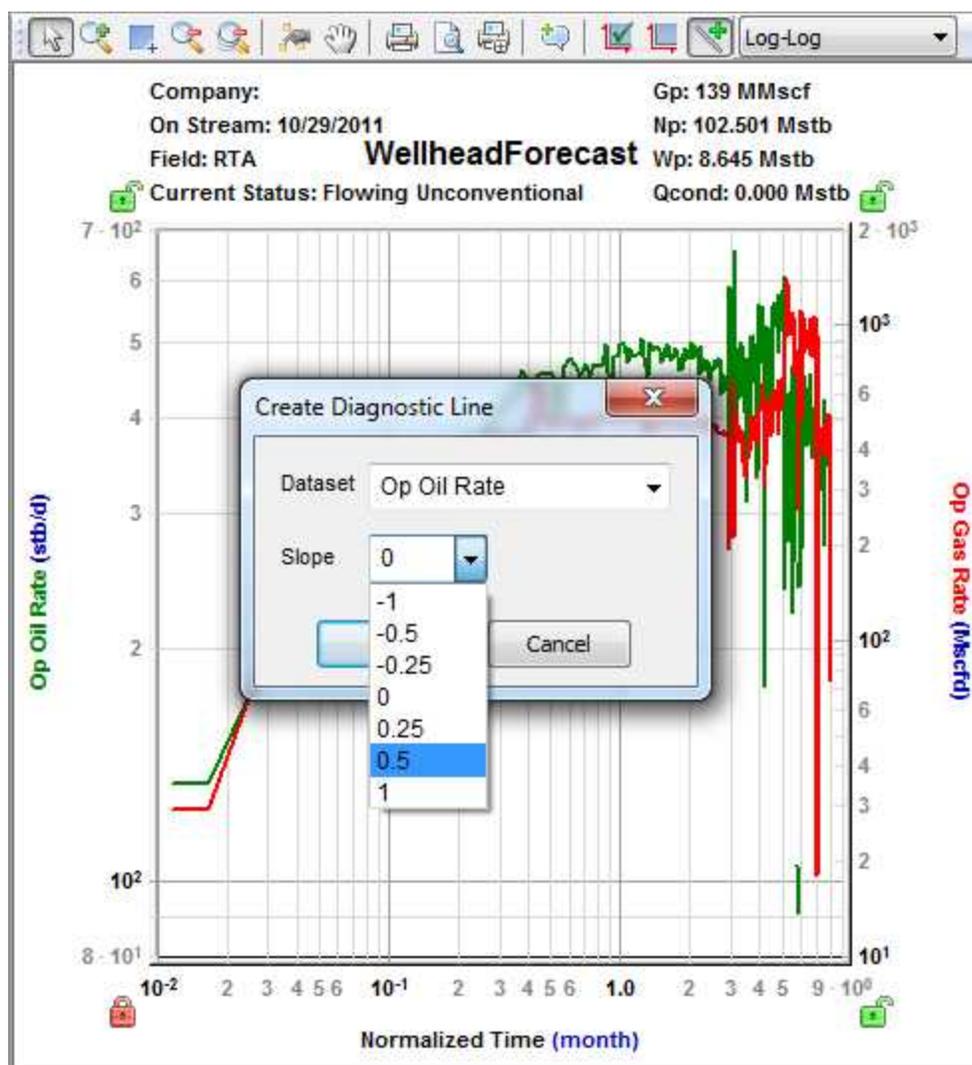
On many of Harmony Enterprise's plots (for example, analysis plot-style worksheets and the [Results Viewer](#) cross-plot), you can add a diagnostic line, which is useful for identifying and extrapolating trends in the data.

To add a diagnostic line, click the **Add a Diagnostic Line** icon () on the toolbar.

A diagnostic line requires at least one dataset or forecast. If there are multiple datasets, a popup opens where you can associate the diagnostic line with a data series. If that data series has one of its axes scaled, the diagnostic line scales with it.



If the plot's vertical and horizontal axes are both set to use logarithmic scales (that is, if the plot is "log-log"), when you click the Add a Diagnostic Line icon, a popup opens where you can select a preset value.



Context menu

Right-clicking the diagnostic line lists these options:

- **Show All Annotations** — displays the x, y coordinates for both endpoints, the slope of the line, denoted by "m", as well as the formula of the line.
- **Customize Line** — for changing the line width and color.
- **Default Slopes** — for changing the slope to a preset value; this is only shown for log-log plots.
- **Remove Line** — deletes the line from the plot.

Line manipulation

You can manipulate the diagnostic line as follows:

- **Rotate** — rotates the line, keeping the center point in its original position
- **Move end points** — drag either end point, while the other end point stays in its original position
- **Move line** — drag near the center of the line to move it to another location

Plot Selection pane

By default, this pane opens in a tab to the right of the [Analysis Manager](#) while a worksheet is in focus. For a description of common icons, see [toolbars](#).

To add / remove plot axes:

- **Checkboxes** — Toggling the checkbox for an item within this pane adds / removes the axis from the worksheet.
- **Double-click** — Double-clicking an item within this pane adds / removes the axis from the worksheet.
- **Drag-and-drop** — Dragging an item from this pane to the worksheet, adds the axis. The item can be dropped to the position you want: x-axis, y-axis, or over an existing axis to link the axes. If you drop the item to a location that is not over an axis, it is added as a y-axis, unless the item is a cumulative or date series.

To customize datasets / categories:

Whenever you modify a custom dataset or category in the [Production editor](#) (add, delete, rename, or update a formula), these changes are reflected in this pane. In order to see renamed items or formula changes from other users, you need to click the **Refresh** icon on the main toolbar.

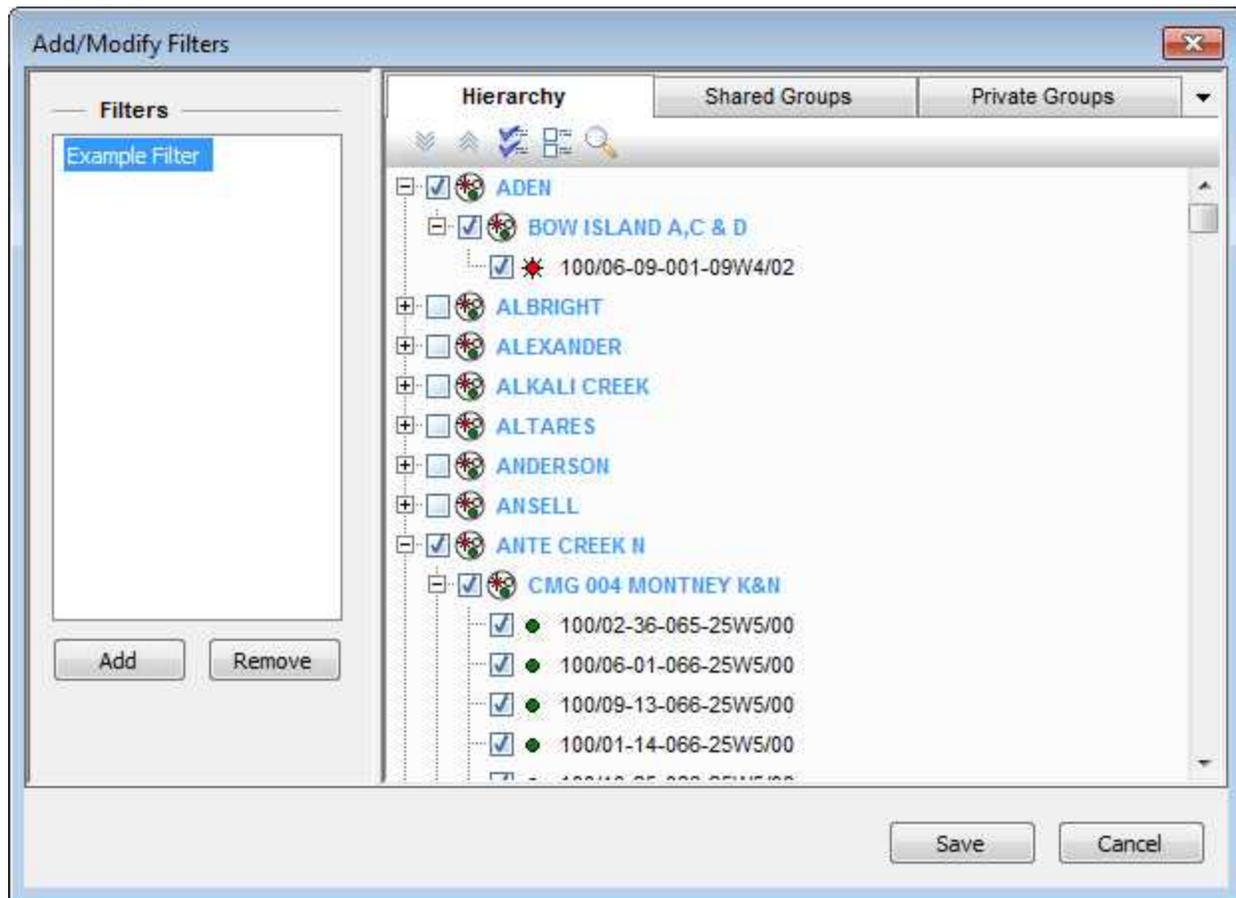
Project filters

Project filters are used to reduce the number of entities displayed in large databases in your specific area of interest. When filters are set, wells and groups outside the filter are not displayed in any of the modules within Harmony Enterprise.

Tip: Project filters are global to the database they are created in. Therefore, any filters you create cannot be seen or used by other users in a multi-user project (that is, all users with access to a Harmony Enterprise SQL project database).

After clicking the Project Filter drop-down list on the main toolbar, you have the following options:

- **Add / Modify Filters** — opens the Add / Modify Filters dialog box where you can:
 - **Add a new filter** — click the **Add** button and type your filter name. Click the checkboxes in the Hierarchy, Shared Groups, and Private Groups tabs to include entities in the filter. Click **Save**.
 - **Modify an existing filter** — select the filter in the Filters pane, and then select the wells and groups you want in your filter (you can select from the Hierarchy, Shared Groups, or Private Groups tabs). Click **Save**.
 - **Delete a filter** — select the filter in the Filters pane and click the **Remove** button.
 - **Rename** — right-click or double-click the filter in the Filters pane, and then type in your new name.
- **No Filter** — displays all of the wells and groups in your project.
- **<previously created filter>** — displays your filtered results on the GIS map, Attributes tab, analysis tabs, and so on.



Tip: When creating a filter, you select your entities using one of the available three tabs.

Hierarchy tab

In the Hierarchy tab, selecting a hierarchy group selects all the wells below it automatically. Constituent wells can be deselected from a hierarchy group, and that hierarchy group is no longer selected in the dialog box. If that hierarchy structure is used when working in the filtered database, a partially selected hierarchy group is displayed. However, any analyses performed on this group only include production from wells included in the filter. When you select the group for analysis, it is locked for other users, which is the same behavior as for an unfiltered database.

Shared and Private Group tabs

Both Shared Groups and Private Groups (custom groups) can be added to filters. In order for a custom group to be included in a filter, *all* wells in the group must also be in the filter. When a

custom group is selected, all its wells are displayed as selected in the Hierarchy tab. If wells are deselected in the Hierarchy tab, and the custom group remains selected, saving the change to the filter fails, and an error message is displayed in the Status Window. If you are modifying a filter created by another user, and your modifications affect private custom groups (you do not have permission to view), an error message is displayed.

Importing with filters

Project filters interact with imports from .harmony files as follows:

- If the well is new to Harmony Enterprise, it is imported and added to the active filter.
- If the imported well is already in Harmony Enterprise and exists in the active filter, Harmony Enterprise attempts to merge the well.
- If the imported well is already in Harmony Enterprise and does not exist in the active filter, Harmony Enterprise skips the import.

Project filters interact with imports from files (everything except *.harmony) as follows:

- If the well is new to Harmony Enterprise, it is imported and added to the active filter.
- If the imported well is already in Harmony Enterprise and exists in the active filter, Harmony Enterprise attempts to merge the well. However, this well is not added to the active filter.

Query Wells dialog box

You can access this dialog box by clicking the **Query Wells** icon in the Entity Viewer - Custom's toolbar (either the Private Groups or Shared Groups tab).

In this dialog box, you can query wells using attribute data, and your queries are saved as custom groups. To limit the scope of your results, well queries use the criteria in your project filters.

Each query includes one or more query statements, and each query statement includes a property, an operator, and a value. The property corresponds to a specific kind of information in the database, the operator is the logical evaluation you want to perform on the property, and the value is what you use to make the logical evaluation. For example:

Property	Operator	Value
Entity Header	Equal	Well 1

Property	Operator	Value
DTOP FORMATION (TVD)	Between	500 and 15,000
Display Name Format	DLS	100/13-076-12W6/00
Spud Date	Calendar	07/22/2016

There are four different property types:

- Text — has these different operators: Equals, Contains, Starts with, and Is Null or Empty. Note that you can paste a list of items in the text field.
- Number — has these different operators: Equals, Greater than or equal to, Less than or equal to, Between, and Is Null or Empty.
- Selectable values — select from a drop-down list.
- Date — has the same operators as numbers, plus you can select a date from a calendar.

Note: You can also have properties for custom attributes. If your query has attributes with units (for example, cumulative gas production), these units correspond to what you have set on the main toolbar using the Toggle Units icon (that is, metric or field units).

Attributes pane

This pane displays all of the available attributes from the database.

To create a query, select the attributes you want to search for from the tree structure, and then refine them on the right-side. For example, if you select Province / State, your operators are Equals, Contains, or Starts with. You could select Equals from the drop-down list, and then type Alberta in the field below. To continue, click the **Add** button. Your query is displayed in the main pane.

Main pane

In this pane, you can refine your query with these operands:

- **NOT** (top right corner) — the inverse / opposite of all the query items below. For example, display wells that are not in Alberta, and basins that do not begin with the letter "a" (applies the OR condition). If you select the NOT checkbox at the top and a NOT checkbox within the query below, the effect is to clear the NOT condition.

-  **DELETE** — either of the delete icons deletes the query item.
- **CHECKBOX** — to enable a query item, click the box, and a checkmark is displayed. To disable a query item, click the box, and the checkmark is cleared.
- **AND** — includes other queries. For example, display wells that are in Alberta and have basins that start with the letter "a".
- **OR** — includes one query or the other (less restrictive than AND). For example, display wells that are in Alberta, as well as basins that start with the letter "a".
- **NOT** — the inverse / opposite of a query. For example, display wells that are not in Alberta, and basins that do not begin with the letter "a".



Icons

These icons are at the top of the main pane:

- **New Query** — resets your existing query, so you can start a new one.
- **Open** — select queries from your saved custom groups. When you open a query, your results are updated with any database changes that occurred after the last time you saved this query.
- **Save** — saves your query as a custom group in the Entity Viewer - Custom pane. When you save a query, your results are updated with any database changes that occurred after the last time you saved this query.
- **Save as** (visible after you have a saved query) — creates a copy of your query. Type a new name for the query you have open.
- **Delete** (visible after you have a saved query) — deletes the query you currently have open. You are prompted to confirm the deletion.
- **Rename** (visible after you have a saved query) — type a new name for the query you have open.

Preview pane

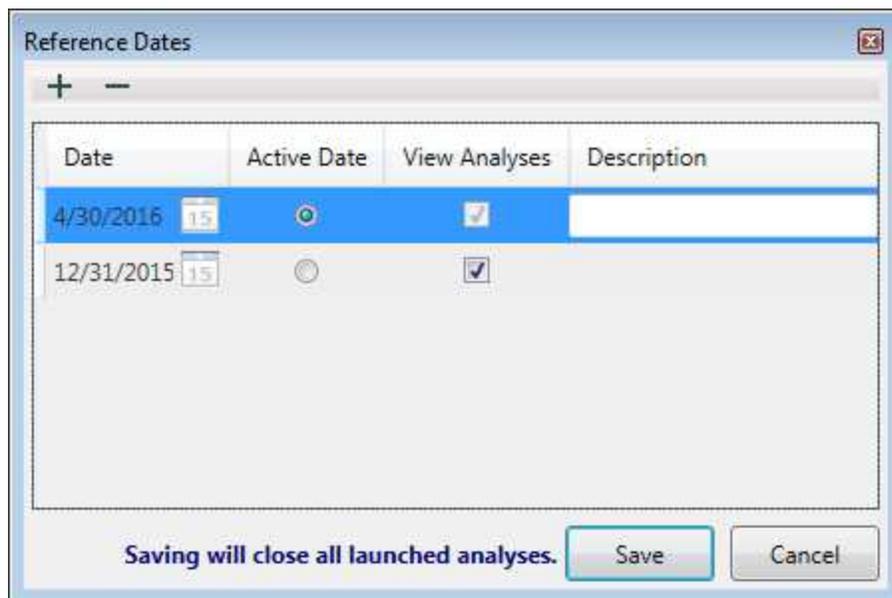
In this pane, the wells that dynamically match your query are displayed with these attributes: Display Name, Province / State, Field, and Reservoir.

By default, the Display Name matches your display in the [Entity Viewer - Hierarchy pane](#) (for example, well name, DLS, API, etc.). Note that clicking column headers sorts the column alpha-numerically, even for columns with numerical values (that is, the Display Name is used to sort numerical columns).

Preview				
Display Name	Province/State	Field	Reservoir	
Oil Well 2 Copy (38)		RTA Copy (38)	Conventional Copy (38)	
Oil Well 2 Copy (213)		RTA Copy (213)	Conventional Copy (213)	
Oil Well 2 Copy (212)		RTA Copy (212)	Conventional Copy (212)	
Oil Well 2 Copy (60)		RTA Copy (60)	Conventional Copy (60)	
Oil Well 2 Copy (49)		RTA Copy (49)	Conventional Copy (49)	
Oil Well 2 Copy (2)		RTA Copy (2)	Conventional Copy (2)	
Oil Well 2 Copy (51)		RTA Copy (51)	Conventional Copy (51)	
Oil Well 2 Copy (33)		RTA Copy (33)	Conventional Copy (33)	

Reference Dates dialog box

In this dialog box, you set the effective date for reserves evaluation, and you can access it by clicking the **Reference Dates** icon () on the main toolbar.



Toolbar

This dialog box has these items on its toolbar:

-  **Add reference date**
 - **Add New Reference Date** — adds a reference date, by default, at the end of the current month.
 - **Duplicate from previous reference date** — adds a reference date with a copy of the analyses from the most-recent previous date. Cumulative volumes at the reference date are determined for the copied analyses using the precedence specified (IP-2P-3P or 2P-1P-3P).
-  **Remove reference date** — deletes the currently selected reference date and any classified analyses associated with this date.

Note: If Well Security is enabled and you do not have the "Manage Security" role, this button is grayed-out.

Grid columns

The reference dates you add are listed in the table / grid and are shared between all users.

- **Date** — only the most recent date is editable by clicking the **Calendar** icon (). Note that after the **Save** button is clicked, the date specified gets committed and cannot be changed.
- **Active Date** — specifies which date is used when classifying analyses. Only one reference date can be specified as the Active Date. The chosen date is user-specific (it is *not* shared), and no date is selected by default.
- **View Analyses** — toggle the View Analyses checkboxes to show or hide analyses with a particular reference date.
- **Description (Optional)** — type a name for your reference date in the Description field.

Clicking **Save** closes all open analyses.

Results tab

The Results tab consists of three sub-tabs: the Results Viewer, Comparison Plot, and Reporting. (The Results Viewer opens when you click the Results tab.)

Results Viewer sub-tab

The Results Viewer has two buttons at the bottom of its pane: Grid View and Plot View.

Grid view

The Grid View displays attributes and results in a table / grid based on selections in the Entity Viewer - Hierarchy or Custom Groups panes. As you change selections, the grid columns are retained, but the entities and their analyses are updated.

The grid is empty until you select attributes and parameters to be displayed. Columns are added to the grid by selecting checkboxes from the tree structure on the left. After you have created a selection of columns in the grid and customized them, you can save it as a template by selecting **Save / Delete Template** from the drop-down list above the tree structure.

Clicking a column header sorts the table data by its attribute value, according to the same sorting rules MS Excel uses. For alphanumeric attributes, numbers are sorted first from left-to-right (instead of top-to-bottom), then special characters, and finally letters. Apostrophes and hyphens are ignored except when there is text with a hyphen. In this case, the text with the hyphen is sorted last. If you click a column header, and then press the **Ctrl** key, you can sort multiple columns at the same time. This is indicated by a sorting arrow in each of the columns.

On Stream	Last Known Record	Cumulative G...
DD/MM/YYYY	DD/MM/YYYY	MMscf
01/09/2001	01/02/2002	11
08/09/2002	10/10/2004	101
01/01/2001	01/01/2003	380
08/06/2004	07/06/2024	1196
01/06/1992	01/03/2006	10012
01/01/1985	01/10/2010	17374
01/01/1985	01/10/2010	18292

Plot view

The Plot View displays the axis parameters you select from the tree structure in a plot; you can plot attribute and result values to analyze relationships between input and output parameters. If you are only plotting attribute values, you do not need to perform an analysis. For a description of plot options, see [plot components](#).

To build the plot for the currently selected entity, select the parameters / datasets you want to display by selecting the appropriate checkboxes in the Results Viewer pane (tree structure). Or, you can drag-and-drop the parameters to the plot.

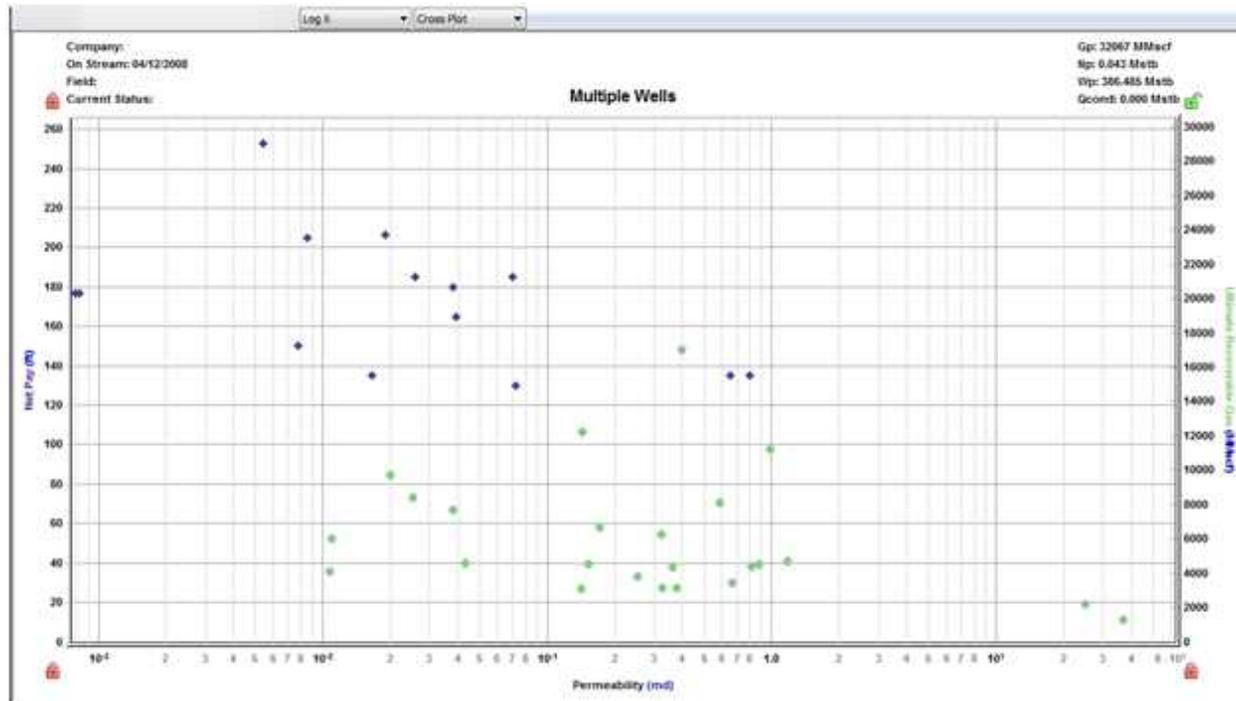
Tip: You can send your plot to a [comparison plot](#), by right-clicking it and selecting **Send Plot to Comparison Plot**, or you can right-click and select **Send Dataset to Comparison Plot**. For information on other options, see [plot options](#).

There are two plot types: cross plot and cumulative distribution function (CDF).

Cross plot

A cross plot displays data as a collection of points, each having the value of one variable determining the position on the horizontal axis, and the value of the other variable determining the position on the vertical axis. This is also known as a scatter plot. These plots are most commonly used for identifying trends or relationships between different variables.

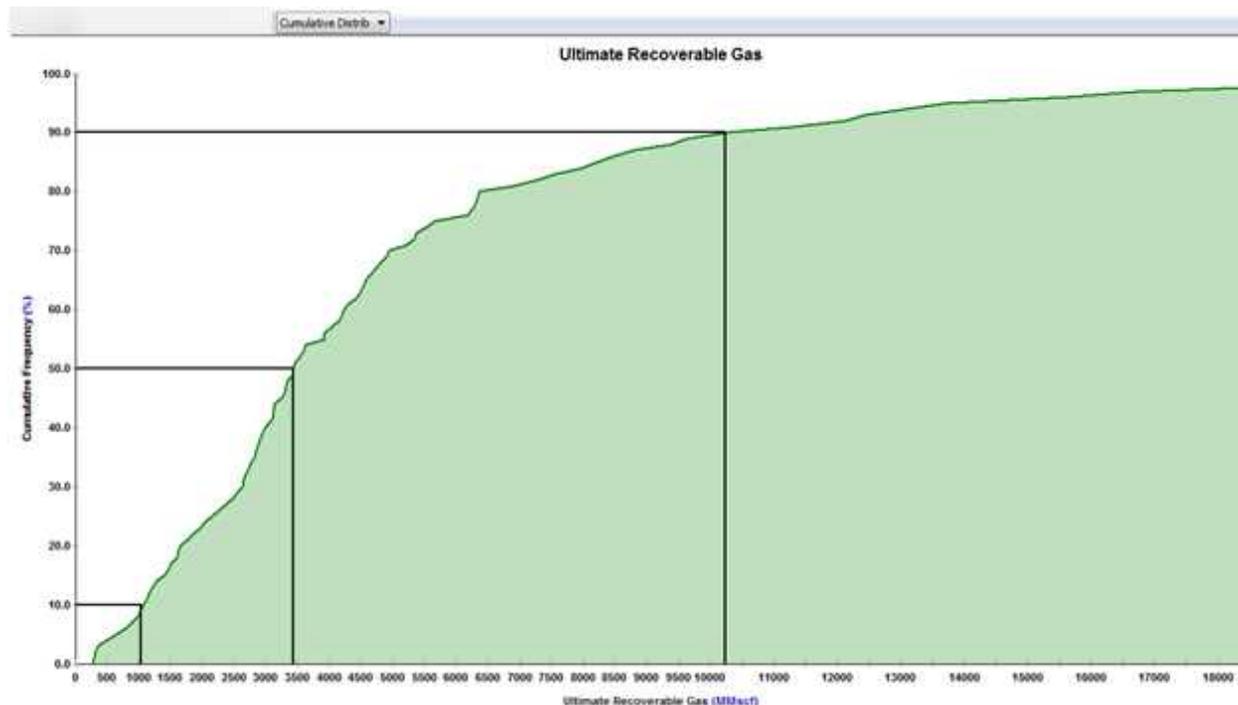
Results can be added to the cross plot by clicking the checkboxes in the tree structure on the left, or by dragging results to the desired axis. Multiple results can be plotted on the y-axes, but only one result can be plotted on the x-axis at a time. (Date variables can only be plotted on the x-axis.)



CDF

A CDF calculates the probability that a random variable with a given probability distribution is found at a value less than or equal to "x".

Only one result variable can be plotted on a CDF plot at a time, and results can only be added by clicking the appropriate checkboxes in the tree structure on the left. If a result variable is already selected, making another selection replaces the current selection.



The black horizontal lines originating at cumulative frequencies of 10%, 50%, and 90% intersect the CDF curve, and then line up with the P90, P50, and P10 values of that dataset, respectively.

Toolbar

The important icons are described below. For a description of common icons, see [toolbars](#).

- (Grid View and Plot View) **Save / Delete Template** — is the default setting, but you can select you saved templates with the plot selections / datasets you prefer.
- (Grid View and Plot View)  **Analysis Filtering** — lists the analysis names that exist for the currently selected entities. Deselecting an analysis name removes all analyses of that name from the plot or grid for all entities. By default, all analyses associated with the selected entities are displayed.
- (Grid View)  **Export Data** — creates a *.csv file of the data displayed in the table.
- (Grid View) **Bulk Edit Declines** — you can edit decline parameters for all the selected wells as a group. For more information, see [bulk modify decline analyses](#).

- (Plot View)  **Search** — after specifying search criteria, the tree structure filters the results to only display parameters that match. The search considers both the description (for example, the initial rate) and nomenclature (for example, q_i) for each parameter.



- (Plot View) **Select data points** — you can select data points, and then to exclude any you do not want, right-click them (to deselect them).

Context menus (grid view)

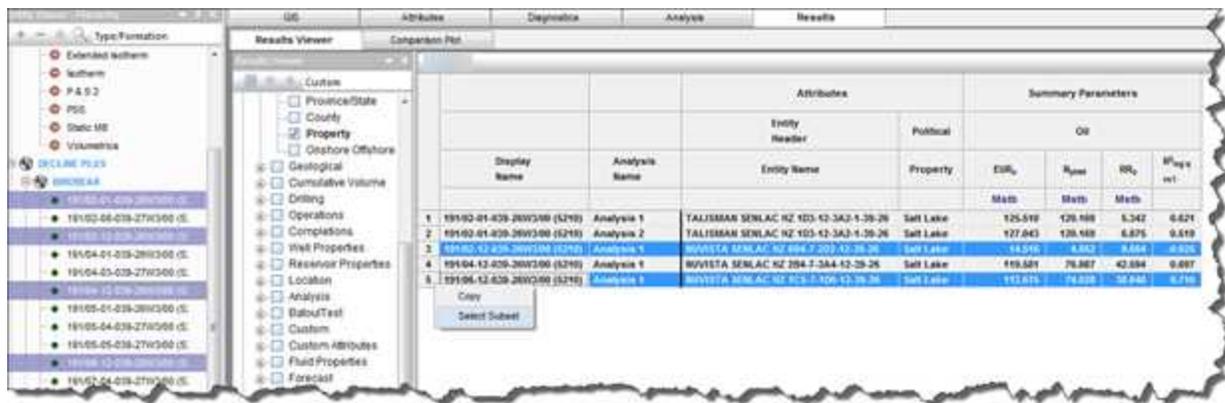
Right-clicking the top left of your table lists these options:

- **Copy Grid** — copies the table to the clipboard.
- **Copy Grid + Headers** — copies the table and table headers to the clipboard.

Right-clicking table headers lists these options:

- **Precision** — select between decimal, scientific, or engineering.
- **Units** — select the units you want to display from the submenu.

After selecting one or more rows in your table, you can right-click the row numbers to the left and select **Select Subset**. This removes the other rows in the table, and this selection persists across Harmony Enterprise (for example, the Entity Viewer, GIS map, and so on).



By right-clicking a table cell, you can copy / paste the table cell's contents.

Comparison plot sub-tab

In the Comparison plot, you can combine plots and/or datasets from many Harmony Enterprise plots. Comparison plots are static (a snapshot of a point in time), meaning that the plot does not change even if the source plot / dataset is modified. This can be useful to compare plots of slightly modified datasets or scenarios, and to compare analyses between entities. Each tab in the Comparison plot contains a separate plot.

Plots created within the Comparison Plot tab are user-specific, meaning they are not shared with other users. The plot and its axes and datasets can be customized, and these changes persist with each plot (such as line / symbol properties, axis title, color, and so on).

Toolbar

The unique icons are as follows:

-  **New Plot** — opens a new blank tab to the right of your existing tabs.
-  **Copy Plot to New Tab** — copies the content of your existing plot to a new tab.
-  **Paste Plot from Clipboard** — pastes the plot in the clipboard to the current tab.
When an axis is added, if it has the same units as an existing axis, they are linked (default setting).
-  **Copy to Clipboard** — copies the plot on the current tab to the clipboard.
-  **Delete Current Plot** — deletes the current tab you are on.
-  **Add an Arrow Annotation** — adds an annotation arrow to the data point you click.



For a description of common icons, see [plot toolbars](#).

Tab context menu

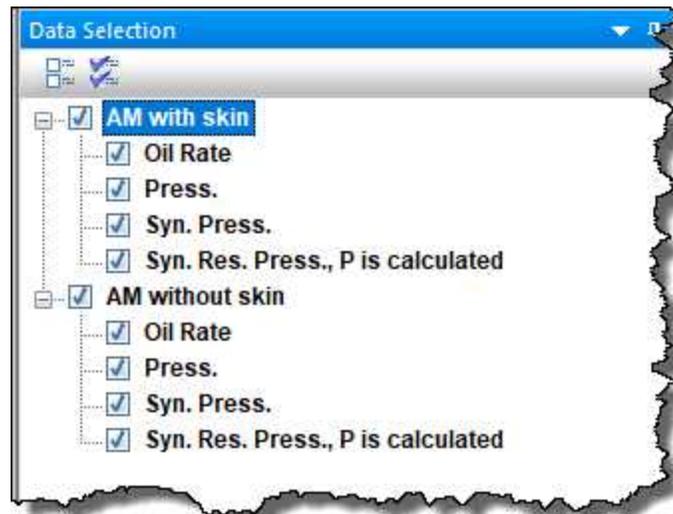
Right-clicking the tab below the toolbar lists these options:

- **New Plot** — opens a new tab to the right of the existing tabs.
- **Copy Plot to New Tab** — copies the content of your current plot to a new tab.
- **Paste Plot from Clipboard** — pastes the plot / dataset in the clipboard to the current tab.
When an axis is added, if it has the same units as an existing axis, they are linked (default setting).
- **Copy to Clipboard** — copies the plot on the current tab to the clipboard.
- **Delete Current Plot** — deletes the current tab.
- **Rename Tab** — opens the tab's name field where you can type a new name.

Plot context menu

Right-clicking within a plot lists these options:

- **Paste plot**
 - Enabled only if a plot is currently in the clipboard.
 - Pastes the plot in the clipboard of the current tab.
When an axis is added, if it has the same units as an existing axis, they are linked (default setting).
 - When any plot is pasted to the comparison plot, all datasets coming from the same plot are grouped together under a parent node in the Data Selection pane. By default, these nodes are the parent name to the originating well / group name, but they can be renamed (for example, to indicate where the data was originally copied from).



- **Paste dataset**
 - Enabled only if a dataset is currently in the clipboard.
 - Pastes the dataset in the clipboard of the current tab. When an axis is added, if it has the same units as an existing axis, they are linked (default setting).

Note: When you hover over the dataset in the plot, the tooltip has the name of the node, followed by the name of the dataset (for example, AM with skin: Oil Rate). You can rename the dataset by right-clicking the plot and selecting Customize Dataset, but the tooltip retains the name of the parent node.

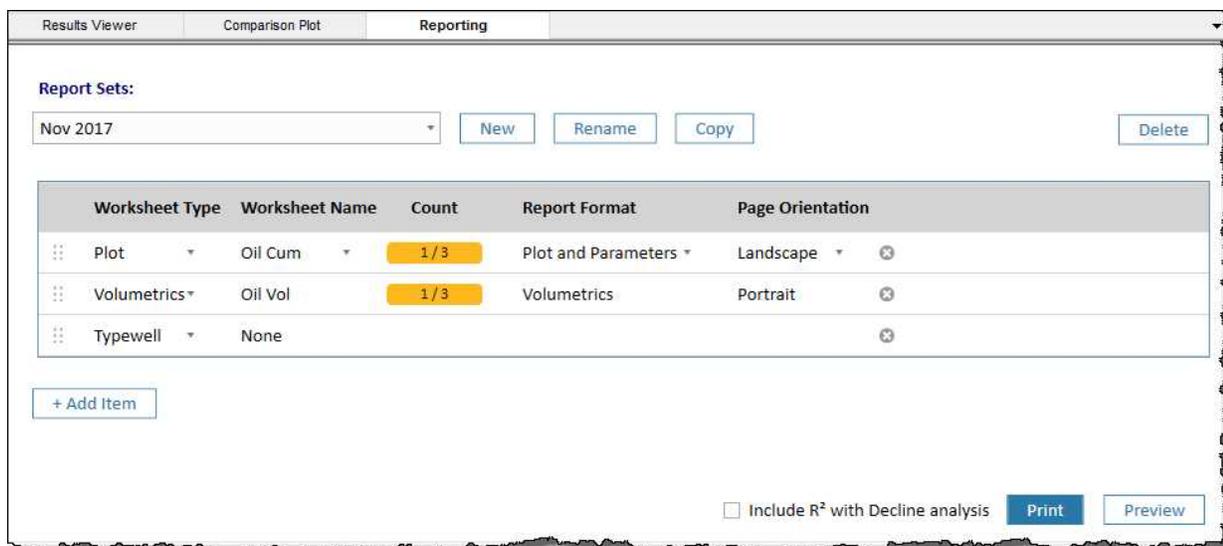
For a description of common plot context menus, see [plot components](#).

Reporting sub-tab

In the Reporting sub-tab, report sets are created to print your specified worksheets using the Report Format you select. Report sets are database specific, and are shared between users connecting to the same database, with the last-saved action persisting. Each report set can include multiple items with no hard limit. The report set and its meta-data are automatically saved when you navigate away.

Note: Reports of plot and analysis parameters have been designed to fit up to nine analyses on the first page, and additional analyses are printed on subsequent pages.

Clicking the **Print** or **Preview** buttons prints the active report set for the entities selected (wells and groups).



If you select multiple entities in the Entity Viewer, a subset of the selection may not have the specified worksheet. If this happens, a warning is displayed to the right of the Worksheet Name column. In this example, 13 of the 14 entities have the specified worksheet name. In the same manner, errors are also displayed to the right of the Worksheet Name column.



These items are defined as follows:

Report Sets — select your previously saved report sets from the drop-down list. If you have not created a report set yet, this drop-down list is blank.

New button — type a name for your report set.

Rename button — type a new name for the currently selected report set.

Copy button — creates a copy of the currently selected report set. Type a unique name for this copied report set.

Delete button — deletes the currently selected report set. You are not prompted to confirm the deletion.

 button — enables you to rearrange rows in your table by dragging-and-dropping.

Worksheet Type column — select Forecast, Plot, Typewell, or Volumetrics.

Note: The reporting feature only supports worksheet types that are created with the Harmony Forecast™ license. Additionally, when you select Plot, worksheets for Decline, Ratio Analysis, or Custom can be used.

Worksheet Name column — select from your list of worksheet names. If you do not have a worksheet for the Worksheet Type you selected, this column displays None. The Worksheet Name drop-down list is blank until you create a worksheet that corresponds with your Worksheet Type selection. If there is only one worksheet that corresponds with your Worksheet Type, it is automatically selected.

Report Format column — if you selected Plot from the Worksheet Type drop-down list, you can select Plot, Parameters, or Plot and Parameters from this drop-down list. Otherwise, this column is not editable because only one report format is supported.

Page Orientation column — select either Portrait or Landscape. For Plot and Typewell worksheets, the default orientation is Landscape; otherwise the default is Portrait.

 **Delete** icon — deletes the currently selected item / row in the table. Note that this icon is only visible after you have added at least one item in the Report Set table.

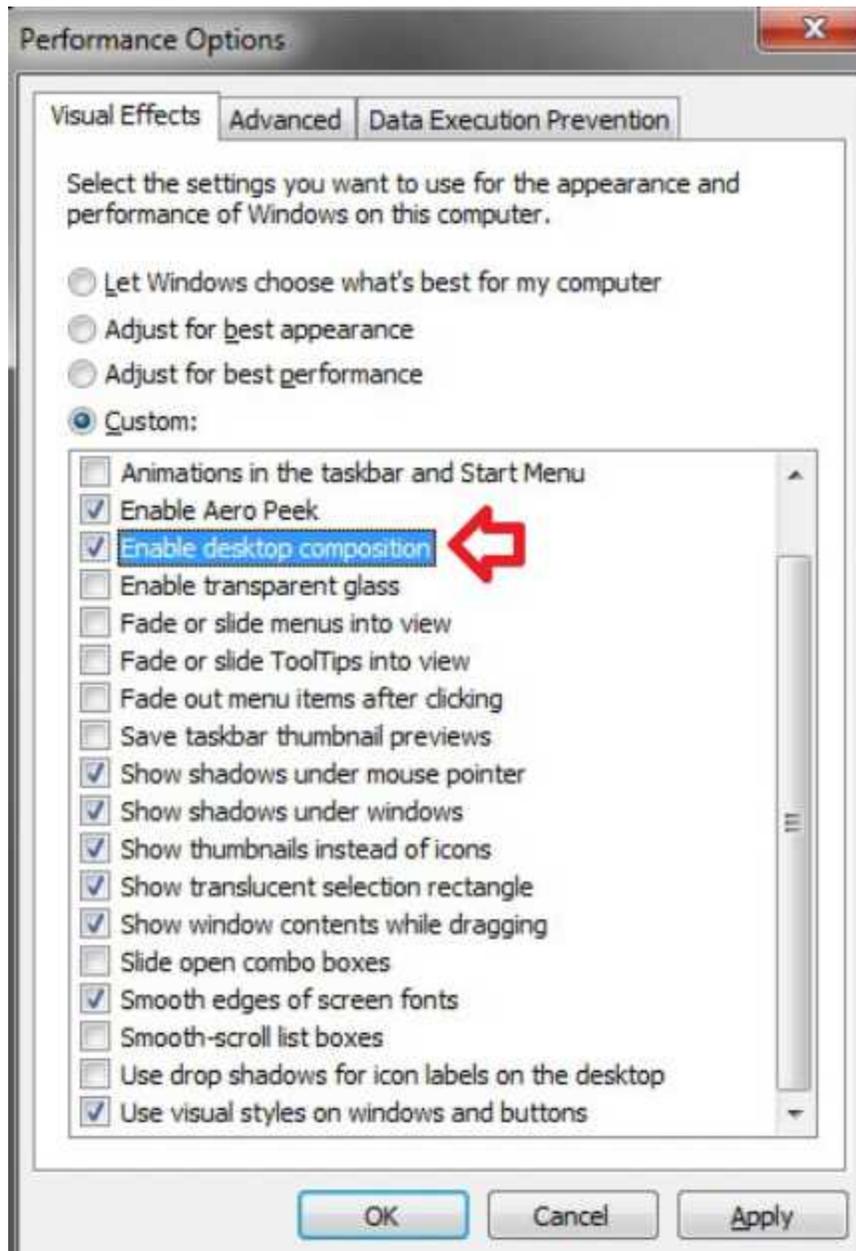
+ Add Item — adds a table row where you can specify your Worksheet Type, Worksheet Name, Report Format, and Page Orientation, by selecting from the drop-down lists.

Include R² with Decline analysis — click this checkbox to include the R² parameter in your reports for Report Formats set to Parameters or Plot and Parameters.

Print — prints the currently selected report set. Entities are printed in the same top-to-bottom order as the Entity Viewer (Hierarchy or Custom), and worksheets for an entity are printed in the same order as the report-set table. Plots are formatted as they look in the Analysis tab.

Preview — opens a Preview window where you can adjust your view, page setup, and print options for the currently selected report set. Entities are displayed in the same top-to-bottom order as the Entity Viewer (Hierarchy or Custom), and worksheets for an entity are displayed in the same order as the report-set table. If you open and close the Preview window, when you open it again, it opens to the last page where you left off.

Tip: (Windows 7) If your Preview window opens without a Close Window button, make sure that the **Enable desktop composition** option is deselected in your Performance Options dialog box (see your Windows help for more information).



Bulk modify decline analyses

This feature is used to change selected decline analysis parameters for multiple entities simultaneously. By clicking the **Bulk Edit Declines** icon () on the Results Viewer - Grid View toolbar,

you can apply changes to all the entities selected in the Entity Viewer. (If any filters have been applied in the table / grid, only the displayed analyses are modified.)

Tip: A brief description for each of the options is displayed after you click the option.

The following parameters are available:

Forecast Start Date (FSD)

- **Slide Forecast Start Date along original forecast line to new Forecast Start Date** — changes the FSD for all declines to the input date. The FSD are slid along the original forecast line to the new start date. Decline parameters of the segment remain the same, but the effective decline rate and initial rate at the FSD will change.



- **Translate entire forecast line to new Forecast Start Date** — changes the FSD for all declines to the input date. The decline forecasts shift in time to the new start date, but the decline parameters remain unchanged. When a decline forecast has a reserves classification, the FSD cannot be set earlier than the reference date.



- **Slide FSD to end of data** — shifts the FSD along the analysis line, rather than translating the entire line. This updates the FSD to the end of production, which is unique for each well.

End Date — changes the end date of the decline forecast to the input date. The decline forecast is truncated or extended to the new end date, and the abandonment rate is adjusted to match. Additionally, there is an option to prevent the end date from being extended.

b — changes the b value for the analysis. For a multi-segment decline, only the first segment's b value is changed. The decline forecast may be truncated or extended as a result.

$d_{lim\ exp}$ — changes the minimum decline rate for declines already set to d_{lim} . The decline forecast may be truncated or extended as a result.

Δt — changes the duration of the forecast to the specified number of months. The decline forecast is truncated or extended to the new duration, and the abandonment rate is adjusted to match. Additionally, there is an option to prevent the forecast from being extended. This is useful in order to "bulk set" declines that end at the earlier of an abandonment rate or end date. This is done by creating declines with the abandonment rate, and then bulk applying the delta t to the forecasts.

Δt history + forecast — changes the duration of the total duration (historical time and forecast) to the specified number of months. The decline forecast is truncated or extended to the new end date, and the abandonment rate is adjusted to match. Additionally, there is an option to prevent the forecast from being extended.

q_f — changes the abandonment rate of the forecast to the specified rate(s). The decline forecast is truncated or extended to the new abandonment rate, and the end date is adjusted to match. If declines for multiple fluid types are displayed / selected, only type values for the fluid types to be changed. Any empty cells are left alone.



Role-based security

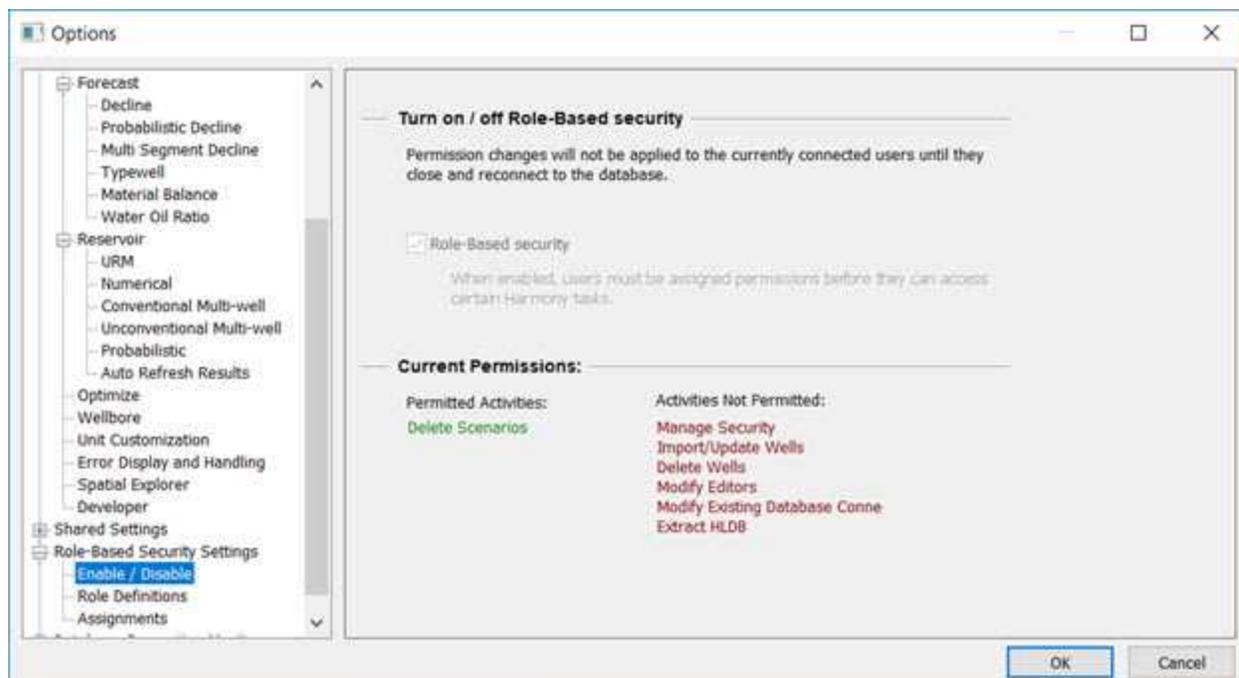
With Role-based security (RBS), you can limit access to certain functions in Harmony Enterprise, based on permissions that are associated with assigned roles. You must enable this option if you want to use well security, and a database administrator can enable this feature after a database is created.

Note: This functionality does *not* apply to .hldb files.

Depending on your role in Harmony Enterprise, you are able to do various things:

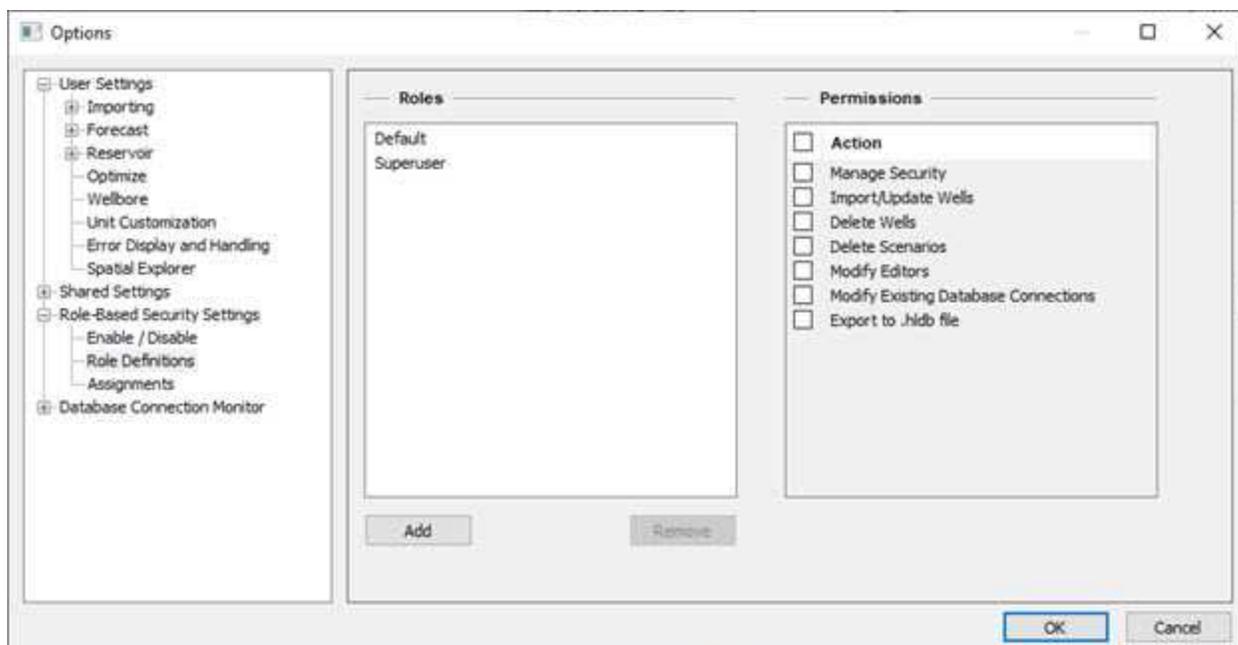
- **Super user** — represents the highest level of authority and their role definitions cannot be altered. This user can create role permissions, and assign role definitions to other users.
- **Default** — (Well Security: **on**) has full access to Harmony Enterprise *except* for the permissions controlled by RBS settings *and* modifying Well Security settings.
- **Default** — (Well Security: **off**) has full access to Harmony Enterprise *except* for the permissions controlled by RBS settings.
- **User-defined roles** — has full access to the rest of Harmony Enterprise along with a combination of any of the following permissions: manage Security settings, import wells / update wells from IHS Markit, delete wells, delete scenarios, modify editors, modify existing database connections, extract to .hldb files, and modify security attributes (if Well Security is enabled).

Role-based security is set in the Options dialog box, under the Role-based Security Settings node. To determine your permissions for your current session, click the **Enable / Disable** node. Any activities that are not allowed are displayed in red text under the Activities Not Permitted heading.

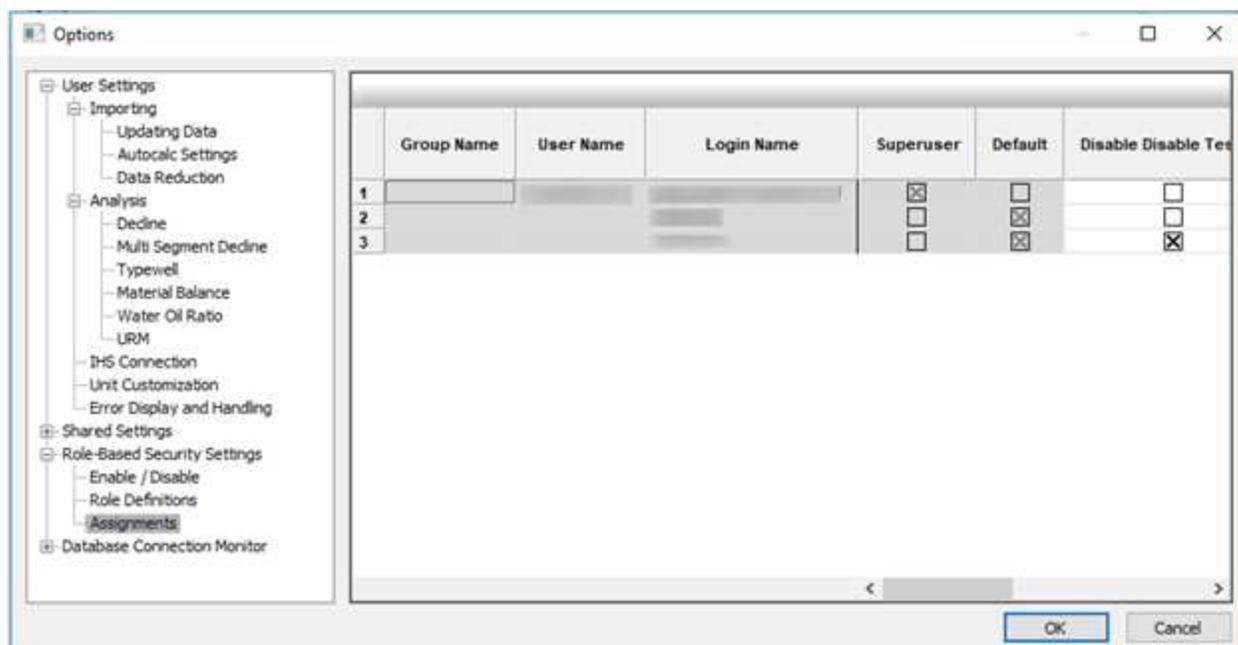


After clicking the **Role Definitions** node, you can add or remove roles. After you have added a role, you can rename it by double-clicking the role name in the Roles pane. (If you do not have

permission to modify roles, the Permissions pane is grayed-out.) By selecting **Modify Editors**, you can change data in the Editors pane.



After clicking the **Assignments** node, you can assign users to various roles by clicking the checkboxes for the access you want to grant. Note that the superuser role cannot be assigned from the dialog box, and therefore it is grayed-out.



The permission you have for a given session remains the same, regardless of whether another user has made modifications to your permissions. To see any permission changes another user has made, requires Harmony Enterprise to be closed and re-opened. These changes persist after you click **OK**. Changes made by a user to their own role or role assignments (when they have the "modify role" permission) take effect immediately after they click OK.

Note: If another user is updating user roles and assignments at the same time, you may need to close the project, reconnect, and try again. If this is the case, an error message is displayed in the Status Window.

Scenarios

With scenarios, you can create a copy of your parent well, so you can perform "what if" scenarios without risking your original data.

Scenarios are created in the Entity Viewer - Hierarchy (toolbar or by right-clicking), and copy the following information:

- attributes
- properties
- wellbore data
- static pressures
- analyses

Note: While you are working with a scenario, it is locked and other users cannot access it.

Even if you have default role-based security with the Modify Editors setting disabled, you can still edit your properties and wellbore for your scenarios, but you cannot promote a scenario.

Core data in the Production editor is read-only (that is, volumes and casing / tubing pressures are kept from the parent well). However, you can still calculate your own sandface pressures by using different properties and a different wellbore configuration.

Importing

When importing new production data, the parent well and all scenarios underneath it are updated. After an import, the other scenarios are static and out-of-date. For sandface pressure

updates, you need to click the **Calculate Sandface Pressure** icon () in the Production editor's toolbar for all scenarios.

Note: If you are using the Import Auto-calculation option to automatically calculate sandface pressures, this function only applies to the parent well.

Spatial Explorer

Spatial Explorer is a geospatial mapping tool used for geological, geophysical, and engineering interpretation.

For more information, see the [Spatial Explorer help](#).

Tables / grids

Harmony Enterprise often displays data in tabular form and uses functionality similar to Excel. For example, you can click-and-drag the bottom right corner of a table cell to copy your data to a range of rows below. The cursor changes to a large X, and you drag the table cell contents to the next row or rows.

	Start Date	End Date	Gas Volume	Water Volume
	MM/DD/YYYY	MM/DD/YYYY	MMscf	scf
1	02/01/1992	03/01/1992	1.828	
2	03/01/1992	04/01/1992	16.497	
3	04/01/1992	05/01/1992	6.034	
4	05/01/1992	08/01/1992		
5	08/01/1992	09/01/1992	0.000	
6	09/01/1992	10/01/1992		

Note: For a description of common table icons, see [table toolbars](#).

To change the height and width of rows and columns, drag the boundary between the header cells.

	P	ψ	Z		B _g	P _g	C _g
	psi(a)	10 ⁶ psi ² /cP			ft ³ /scf	lb/ft ³	1/psi
1	0.00	0.000					
2	10.00	1.779e-02	0.999		2	0.03	1.00e-01
3	20.00	4.449e-02	0.997		1	0.06	5.01e-02
4	30.00	8.905e-02	0.996		1	0.09	3.35e-02
5	40.00	1.515e-01	0.995		0	0.12	2.51e-02
6	50.00	2.319e-01	0.993		0	0.15	2.01e-02
7	60.00	3.303e-01	0.992		0	0.18	1.68e-02
8	70.00	4.468e-01	0.991		0	0.21	1.44e-02

To move a column to a new location, click-and-drag the column you want to move. The cursor changes to a gray box with a checkmark, and when you release your mouse button, the column moves to its new location.

	Start Date	End Date	Water Volume	Gas Volume
	MM/DD/YYYY	MM/DD/YYYY	stb	MMscf
1	02/01/1992	03/01/1992	0.0	1.828
2	03/01/1992	04/01/1992	0.0	16.497
3	04/01/1992	05/01/1992	0.0	6.034

Context menus

Right-clicking an entire table or columns in a table, display different context menus.

Entire table

To copy an entire table, right-click the top-left cell of a table and select one of these options:

- **Copy Grid** — copies the table to the clipboard.
- **Copy Grid + Headers** — copies the table and table headers to the clipboard.

	p	ψ	Z	B _g	ρ _g	c _g
				ft ³ /scf	lb/ft ³	1/psi
1						
2			0.999	1.63e+00	0.03	1.00e-01
3	20.00	4.449e-02	0.997	8.15e-01	0.06	5.01e-02
4	30.00	8.905e-02	0.996	5.43e-01	0.09	3.35e-02
5	40.00	1.515e-01	0.995	4.06e-01	0.12	2.51e-02
6	50.00	2.319e-01	0.993	3.25e-01	0.15	2.01e-02
7	60.00	3.303e-01	0.992	2.70e-01	0.18	1.68e-02
8	70.00	4.468e-01	0.991	2.31e-01	0.21	1.44e-02

Columns

To copy one or more columns of a table, select your columns by clicking their headers, and then right-click and select **Copy**.

	p	ψ	Z	B _g	ρ _g	c _g
	psi(a)	10 ⁶ psi ² /cP		ft ³ /scf		1/psi
1	0.00	0.000				
2	10.00	1.779e-02	0.999	1.63e	0.03	1.00e-01
3	20.00	4.449e-02	0.997	8.15e	0.06	5.01e-02
4	30.00	8.905e-02	0.996	5.43e-01	0.09	3.35e-02
5	40.00	1.515e-01	0.995	4.06e-01	0.12	2.51e-02

After you have copied your content from a table, you can paste it to another application (for example, Excel).

To change the precision and/or units displayed in a column, right-click the numeric columns' headers (the columns displaying units in green text).



- **Precision** — select between decimal, scientific, or engineering.
- **Units** — select the units you want to display from the submenu.

	p	ψ	Z	B _g	ρ _g	C _g
	psi(a)	10 ² psi ² /cP		ft ³ /scf	lb/ft ³	1/psi
1		Precision ▶ 00				
2	1			1.63e+00	0.03	1.00e-01
3	20.00			8.15e-01	0.06	5.01e-02
4	30.00	8.905e		5.43e-01	0.09	3.35e-02
5	40.00	1.515e		4.06e-01	0.12	2.51e-02
6	50.00	2.319e		3.25e-01	0.15	2.01e-02
7	60.00	3.303e		2.70e-01	0.18	1.68e-02
8	70.00	4.468e		2.31e-01	0.21	1.44e-02
9	80.00	5.812e		2.02e-01	0.24	1.26e-02
10	90.00	7.337e		1.79e-01	0.28	1.13e-02
11	100.00	9.042e		1.61e-01	0.31	1.01e-02
12	110.00	1.093e+00	0.986	1.46e-01	0.34	9.23e-03

Note: Changing the precision only affects the way values are displayed. All of the calculations use exact values, even if the displayed value looks rounded-up.

Well layers

With layers, you can subdivide a well into component layer sections, so you can perform multilayer analysis.

Layers for multilayer wells can only be created or deleted in the [Entity Viewer - Hierarchy](#). Individual layers cannot be seen in the [Entity Viewer - Custom](#).

Layer entities, once created, behave similarly to well entities, by having their own properties, production data (calculated), attributes, and analyses.

Note: Layer entities do not have their own Static Pressure editor or their own Wellbore editor.

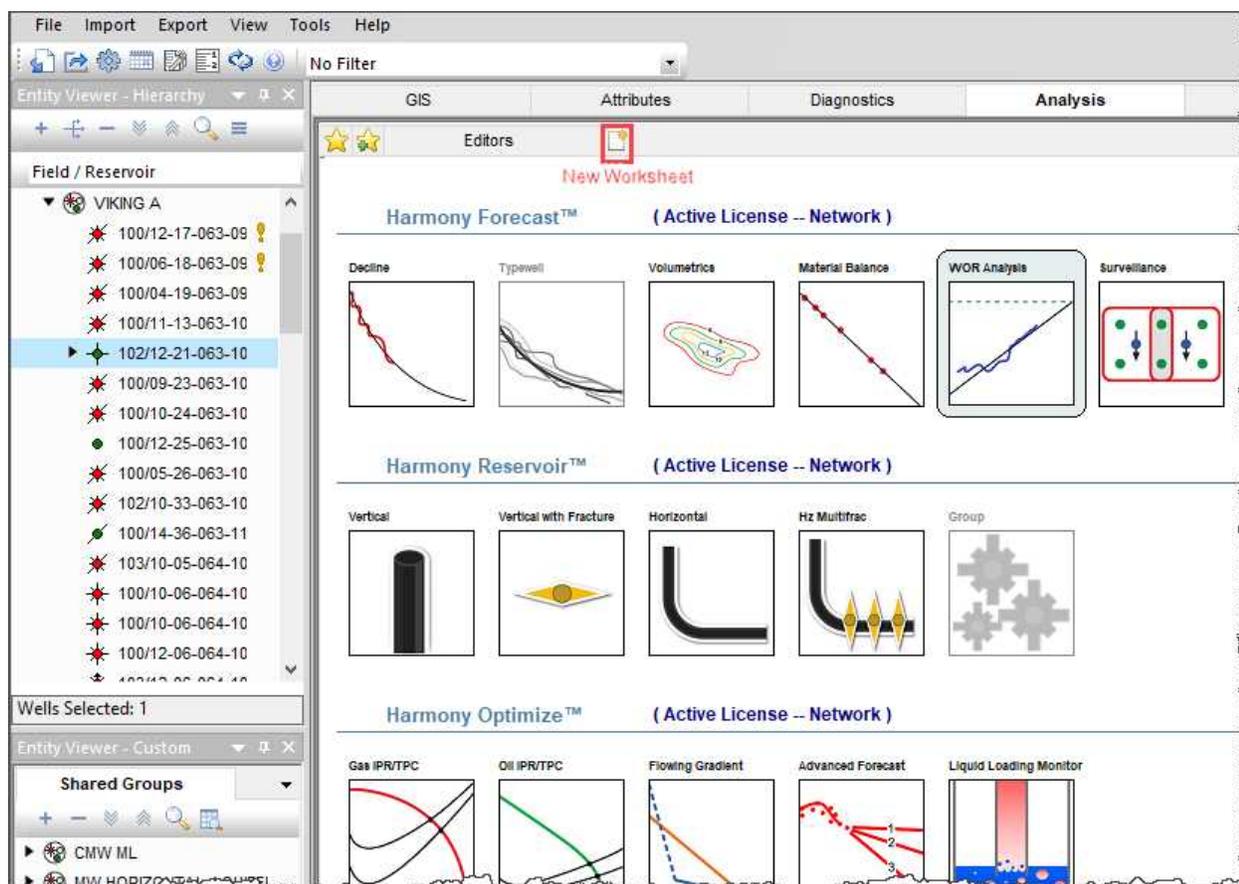
Worksheets

Worksheets are plots or tables of entity data and analyses. Worksheets are related to the currently selected entity for analysis (a well or group), and each worksheet can be used for one or many analyses. You must [add a worksheet](#) before you can analyze an entity.

The New Worksheet tab opens when you [select an entity for analysis](#), or click the New Worksheet tab.

An important distinction exists between Forecast, Reservoir, and Optimize worksheets.

- Forecast worksheets support multiple analyses and these analyses can be displayed on multiple worksheets (*many:many relationship*). With Forecast worksheets, click your worksheet, and then select from the context menus (if applicable).
- Reservoir worksheets support one analysis and this analysis is displayed on one worksheet (*one:one relationship*). With Reservoir worksheets, click your reservoir, and then select the fluid, analysis, and model (if applicable).
- Optimize worksheets support multiple analyses within their respective worksheets (*many:one relationship*). With Optimize worksheets, click your worksheet to get started.



For group analyses, (for example, typecurve, FMB), click **Group** and select your worksheet from the context menu.

After working on your analysis, you can click another tab and your work is automatically saved. If you want to export specific wells and later import them back into the database, see [export to an .hldb file](#).

Harmony Enterprise supports the following worksheets:

Harmony Forecast™ License (links to various worksheets)	Harmony Reservoir™ License (links to various analyses)	Harmony Optimize™ License (links to various analyses)
Decline	Typecurve	Gas IPR / TPC (inflow / outflow)
Typewell	FMB	Oil IPR / TPC (inflow / outflow)
Volumetrics	URM	Flowing Gradient
Material Balance	Analytical	Advanced Forecast
WOR Analysis	Numerical	
Forecast	Probabilistic	
Custom	Custom	

Decline worksheet

Decline worksheets display the production data of a well using the selected plot options (such as, time or cumulative production for the x-axis). These worksheets can be used to add, display, and modify decline forecasts based on your production data. For more information, see the [analysis manager](#) and [plot selection pane](#).

Note: This worksheet works with your Harmony Forecast™ license.

In the decline category, you can select these plot types for gas, oil, water, and barrel of oil equivalent (BOE):

- **Rate Time** — production rates are plotted against time on a semi-log plot
- **Rate Cum** — production rates are plotted against cumulative production on a coordinate plot
- **Cum Time** — cumulative production is plotted against time on a coordinate plot. Note that this is a read-only display and the decline cannot be modified on this plot.

Default decline worksheets can be modified in the [Plot Selection pane](#).

In the Analysis Manager, you can add numerical forecasts for gas, oil, or water.

You can also add condensate decline analyses (that is, [Arps](#), [multi-segment](#), [stretched exponential](#), and [Duong](#)) to your decline worksheet, but the procedure is different. For more information, see [analyzing an entity](#).

BOE

The BOE applies to wells and groups, and it is of interest because oil and gas are often produced together. The BOE is calculated as oil volume + gas volume / factor. This factor can be changed from the default value of 6.00 Mcf/bbl in the Production Calculations section of the Options dialog box (**Tools** menu, **Options**).

Important: This value is shared by all users, and updating this value affects new and existing analyses.



If you set this factor to less than one, an error message is displayed in the Status Window and the value resets to six.

Typewell worksheet

The typewell worksheet is used to view well-level production on a group of wells and calculate average performance. This can be used to create a forecast for wells with limited or no historical production based on a relevant group. A typewell worksheet can also be created and average performance determined for ratios.

Note: This worksheet works with your Harmony Forecast™ license.

You can add the following typewell worksheet types:

- Rate typewells:

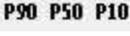
- gas
- oil
- water
- BOE
- condensate
- Ratio typewells:
 - CGR (condensate-gas ratio)
 - WGR (water-gas ratio)
 - GOR (gas-oil ratio)
 - WOR (water-oil ratio)

Note: Note: The traditional decline analysis is available for each of the above rate typewells. The Ratio Trend is available for ratio typewells.

Note: Cumulative production is not viewable in the Plot Selection tab for ratios.

Plot toolbar

You can toggle different datasets by clicking these icons on the toolbar above the plot:

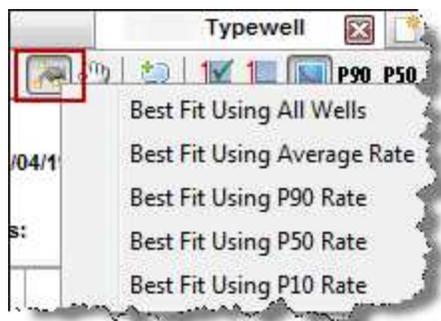
-  **Select a Best Fit range using the options listed** — see [best fit](#).
-  **Show / Hide Average rate** — by default, the average rate / ratio is shown. Click this icon to show / hide the average rate / ratio on the plot. The arithmetic average of all selected wells is determined in each period.
-  **Show / Hide Wells** — by default, all wells are shown.
-  **P90 / P50 / P10 rates** — by default, all these calculated datasets are hidden. Click the [P90](#), [P50](#), or [P10](#) icons to show / hide these various rates / ratios on the plot.
-  **Show / Hide Number of Producing Wells** — you can display the number of producing wells in each period.

-  **Append historical production with selected forecast** — you can use an individual well's historical production and forecasts to create a typewell forecast. This is only available for rate typewells.
-  **Color Management** — select from these options:
 - **All Grey** — displays all wells in a gray color.
 - **All Unique** — displays each well in a unique color.
 - **Color by Attribute** — opens a submenu where you can select a specific attribute. All wells with the same attribute appear in the same color.
-  **Settings** — select which calculations you want to display on the plot:
 - **Rate Calculations** — select All Rates or Producing Rates Only.
 - **Aggregate of Sublevel** — when a hierarchy group more than one level above the individual wells is selected, the wells within all of the subgroups are displayed, by default. With this option, you can display the aggregated subgroups in place of individual wells.
- **Plot drop-down list** — select your plot type from the drop-down list: log y, coordinate, log-log, or log x.

For a description of common icons, see [plot toolbars](#).

Best fit

There are several tools that you can use to create a "best fit" using the point-selection method. Selecting any of these options opens the Set Axis Ranges dialog box where you can define the portion of data to be used for the best fit.



Plot Selection tab

The Plot Selection tab lists the options for your plot.

X-axis:

- **Normalized Time** — This option plots well data as cumulative time from 'time zero' (0 on the x-axis) rather than as dates. Time periods are displayed in increments of months or days. If the increments are mixed within the group, the lowest-resolution time period is used to ensure consistency. When the average line is calculated, each producing well's rate is averaged at each period.
- **Normalized Flowing Time** — This option is similar to normalized time, but all shut-in, missing, or blank periods are removed from each well's production history.
- **Cumulative Production** — Production volume is displayed based on volume produced per time period. (The period size is the one the data is imported in.) When creating the average well, all wells are aggregated to the lowest resolution period, and the average production volume and rate are determined for each period.
- **Resolution** — Toggle between Daily and Monthly.

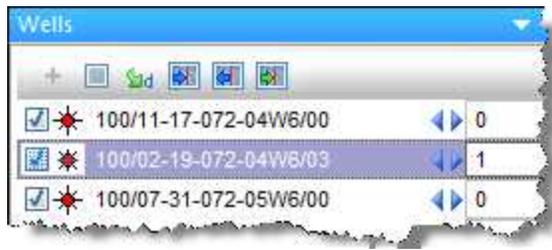
Y-axis:

- **Rate** — This option displays the rates for each well in the group and uses these rates to create the average well's rate.
- **Rate per Attribute** — Well rates are normalized (that is, divided) by the value of the selected attribute. If the attribute is blank, the well's production history is not displayed.
- **Rate Type** — Toggle between Operated Rate and Calendar Rate.
- **Cumulative Production** — Production volume is displayed based on volume produced per time period. (The period size is the one the data is imported in.) When creating the average well, all wells are aggregated to the lowest resolution period, and the average production volume and rate are determined for each period.
Note that if you select this for your y-axis, the typewell becomes read-only.
- **Ratio** — This option displays the ratio for each well in the group and uses these ratios to create the average well's ratio.
- **Ratio per Attribute** — Well ratios are normalized (that is, divided) by the value of the selected attribute. If the attribute is blank, the well's production history is not displayed.

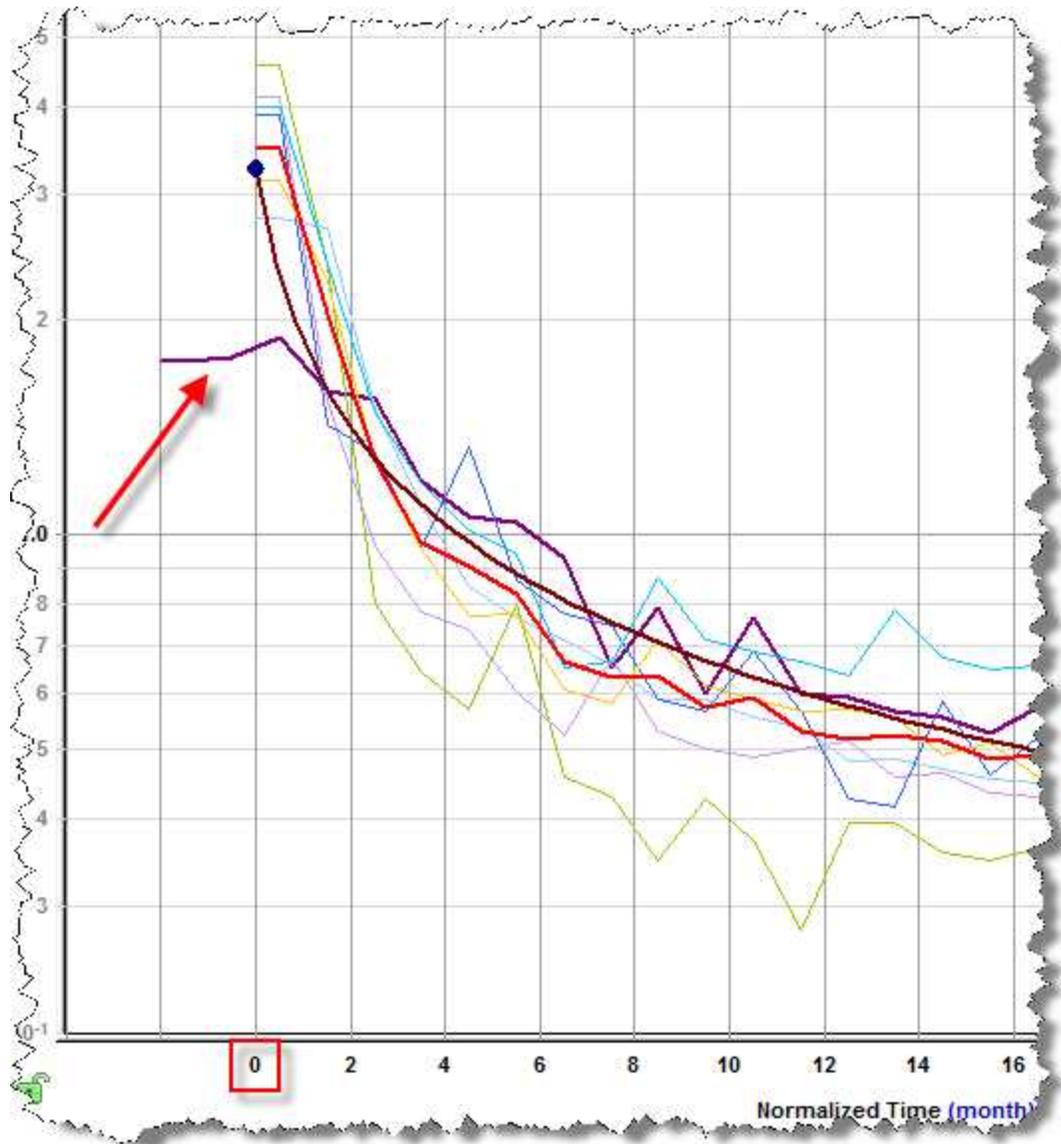
Wells tab

Use the Wells tab to synchronize well settings between typewell worksheets via the toolbar. In addition, you can change the start period of a well by entering a value in the Start Date Offset

boxes, or by clicking the blue left- or right-facing arrows next to the boxes.



The number in the box corresponds to the time period in which production data starts for the well. (On a time plot, this is either months or days. On a cumulative plot, this is production volume produced in that time period. Therefore, a well with larger production volume moves more than a well with less production volume.)



Anything to the left of time zero (0 on the x-axis) is not used for the calculated lines or the decline forecast.

Hovering over a well temporarily displays a thicker line for the associated dataset on the plot.

A selection can be made within the Wells tab, or on the plot. Selections are maintained between the Wells tab and the plot. A selected dataset is displayed with a thicker line to indicate that it is selected.

Wells can be selected in the Wells tab using standard selection behavior (including using the Ctrl and Shift keys). For more information, see selecting entities.

Clicking a dataset clears the existing selection, and then selects the new dataset. Pressing the **Ctrl** key while selecting a dataset adds / removes the dataset from the existing selection.

Toolbar

This tab has the following icons on its toolbar:

-  **Duplicate Selected into** — copies the selected wells, so you can paste these wells into a custom group.
-  **Check all / uncheck all** — selects or deselects all of the wells displayed on the plot
-  **Apply Selections from another Typewell Worksheet** — gets selections (selects the same wells) and spinner values (offset values that translate the rate history for a well) from another typewell worksheet in the same custom group.
-  **Set Start Date Offsets to Zero** — sets all well offsets to zero.
-  **Set Start Date Offsets to Peak Rate** — sets all well offsets to the well's peak rate – time zero for the well becomes the peak rate instead of the first period.
-  **Set Start Date Offsets to Specified Value** — opens the Shift Spinner Value dialog box where you can set your well offsets (positive values only). This moves the plot to the right (0 corresponds to the beginning of production data). You can also use the blue left- or right-facing arrows on the Wells tab.

Context menu

Right-clicking wells on this tab lists these options:

- **Duplicate Selected into Shared Custom Group** — copies the selected wells into a new or existing shared custom group.
- **Duplicate Selected into Private Custom Group** — copies the selected wells into a new or existing private custom group.
- **Move Selected into Shared Custom Group** — moves the selected wells into a shared custom group. Only available if the active group is a Custom Group.
- **Move Selected into Private Custom Group** — moves the selected wells into a private custom group. Only available if the active group is a Custom Group.

Analysis Manager tab

The Analysis Manager tab has an Analysis Manager pane and an Analysis Parameters pane. The Analysis Manager only shows typewell analyses, unlike other worksheets, which show all analyses while disabling ones that cannot be displayed on the plot.

Decline and multi-segment decline analyses displayed on the rate typewell worksheet have their forecast start dates matched to the start date of the first segment, and the forecast always starts at $t / Q = 0$.

Volumetrics worksheet

The volumetrics worksheet is used to view gas and oil volumetrics analyses. For more information, see the [volumetrics analysis](#).

Note: This worksheet works with your Harmony Forecast™ license.

Click to show / hide an example screenshot

The screenshot displays the 'Analysis Manager' window with a tree view on the left and a 'Gas Vol' editor on the right. The tree view shows a hierarchy of analysis types, with 'Analysis 1' selected. The 'Gas Vol' editor contains several sections of data:

Reservoir Properties		
P_i	48263.3	kPa(a)
T_R	125.0	°C
h	13.1	m
λ_t	7.00	%
S_{gl}	19.93	%
S_{ol}	63.00	%
S_{wt}	7.00	%

Gas Properties		
B_{gl}	3.42e-03	m ³ /m ³
<input checked="" type="checkbox"/> Calculate B_{gi}		
G	0.932	
N_2	0.00	%
CO_2	0.00	%
H_2S	0.00	%
<input checked="" type="checkbox"/> Adsorption		
V_{Ls}	1	cm ³ /g
P_{Ls}	2.0	kPa(a)
ρ_b	2.60	g/cm ³
<input checked="" type="checkbox"/> Adsorption Saturation		
ρ_{ads}	0.42	g/cm ³
S_{ads}	10.07	%

Volume Parameters

Material Balance worksheet

The Material Balance worksheet is used to view gas material balance analyses. For more information, see the [materials balance analysis](#).

Note: This worksheet works with your Harmony Forecast™ license.

WOR Analysis worksheet

With water-oil ratio (WOR) worksheets you can use oil ratios vs. cumulative oil or vs. time, to forecast oil and water rates in a high-water cut. In these cases, abandonment criteria is often related to both oil and water production. By providing the total fluid rate, forecasts for oil and water are calculated.

Note: This worksheet works with your Harmony Forecast™ license.

For more information, see [water-oil forecasting theory](#).

You can select from the following default worksheets:

- **WOR vs. Cumulative Oil** — presents the water-oil ratio (WOR) from a historical perspective. It has little or no analysis value. The WOR + 1 analysis curve can be presented on this plot.
- **WOR + 1 vs. Cumulative Oil** — this is our main analysis plot for estimating oil EUR by extrapolating the linear portion of the WOR + 1 trend. This plot is used because it helps ensure you only use the data where water cut exceeds 50% and it tends to produce more reliable linear trends. This plot can be used directly to extrapolate EUR because the x-axis is cumulative oil, or it can be used as a trend line in the Forecast worksheet to create an oil-rate forecast based on a projection of Total Liquids Rate (Oil + Water). This is a crude, but workable method.
- **Water cut vs. Cumulative Oil** — water cut can be defined as the ratio of water produced compared to the volume of total liquids produced. The water cut in water-drive reservoirs can reach very high values (from the Schlumberger Oil-field Glossary).
- **Oil cut vs. Time** — is a method sometimes used for wells with very high WORs to linearly extrapolate similar oil rates to an economic oil-cut limit. It can be very dangerous because it encourages you to identify and extrapolate trends that may be partially or entirely created by measurement errors, and not due to progressive saturation changes in the reservoir.

You can add your own worksheets, but the WOR analysis can only be added when the required axes are present.

Forecast worksheet

The forecast worksheet displays raw data for existing production forecasts in a table. The forecast worksheet can also be used to create a ratio forecast from an existing forecast using an

input ratio.

Note: This worksheet works with your Harmony Forecast™ license.

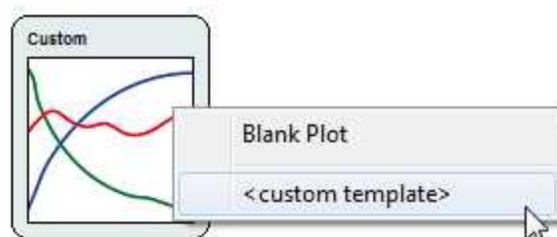
On this worksheet, forecasts start at the forecast start date. You can change your table resolution by clicking the **D** (day), **M** (month, the default setting), or **Y** (year) icons on the toolbar. For a description of common icons, see [table toolbars](#).

If you imported a Piper® Forecast, it is displayed with a "- Piper Forecast" suffix (for example, Gas - Piper Forecast, Oil - Piper Forecast, or Water - Piper Forecast) as a Custom Forecast.

Custom worksheet

The custom worksheet is a blank worksheet where you can display the parameters you select on the [Plot Selection pane](#). In addition, you can select the custom templates you create in the [Diagnostics tab](#).

Note: This worksheet works with your Harmony Forecast™ license.



For a description of common icons, see [toolbars](#).

Reference materials

Reference materials include the following:

- analysis theory
- calculations & correlations
- general concepts
- nomenclature
- references

Analysis theory

Analysis theory includes the following:

- Analytical
- Decline analysis
- FMB | Multiphase theory, Model theory
- Duong decline
- Gas IPR / TPC
- Liquid Loading Monitor
- Material balance
- Numerical model
- Numerical URM
- Oil IPR / TPC
- Probabilistic
- Probabilistic decline method (beta)
- Stretched exponential decline
- Surveillance
- Typecurve | Agarwal-Gardner, Blasingame, Compound linear, Fetkovich, NPI, Transient, Wattenbarger
- Typewell

- Unconventional reservoir
- Volumetrics
- WOR forecasting

Analytical models theory

Modeling is the process of history matching pressure and rate transient data based on a mathematical model. There are many different models available to match the data depending on the situation. Thus, it is important to analyze the pressure and rate transient data before modeling because it forces the analyst to think about the probable reservoir configurations and provide good estimates of reservoir parameters. Models are not unique (different model types can match the same set of data), and as a result, we recommend selecting the model type after the analysis step. The following summarizes the advantages of modeling pressure and rate transient data:

- Modeling makes use of all the information within a dataset. For example, while analyzing data from vertical wells, the analyst might try and determine permeability and skin by analyzing the data points that make up the zero slope on the derivative plot, and the semi-log straight line on the radial plot, but ignore the data points in the transition period between wellbore storage and radial flow. Models make use of the information contained in transition periods.
- Modeling takes all flow regimes into account. In multi-rate situations, analyses depend on the superposition of the equation for a single flow regime. For example, the derivation of Horner time includes the assumption that all flow, including the entire drawdown, is radial. Modeling does not assume that only one flow regime has occurred.
- With modeling, you can simultaneously analyze multiple flow periods, so that a single set of parameters can be found.

Parameter values obtained during the analysis step provide a good starting point for an appropriately chosen model type. Parameters can then be optimized by automatic parameter estimation (APE). Before using the APE method, corrupted data should be removed from the dataset to prevent the attempt to match invalid points.

Choice of model

As stated above, different models can be used to match a single set of data. Choosing a probable model type requires the consideration of a number of factors including seismic data, geology, log data, and information provided from other wells drilled in the same formation.

The choice of model can drastically change the outcome of a forecast. For example, pressure and rate transient analysis of radial flow data can be used to find the reservoir flow capacity (kh). The analyst must decide which model is better.

Model assumptions

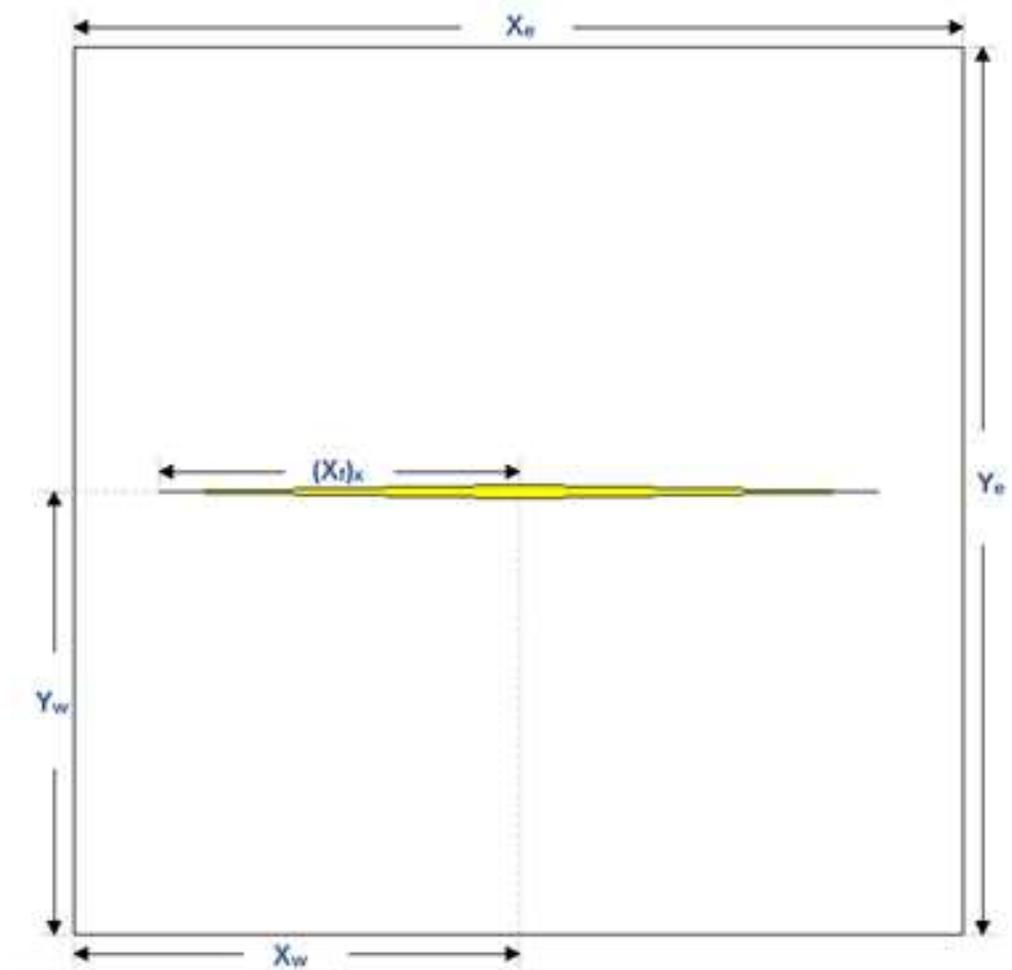
There are many assumptions that go into the model itself which can lead or mislead the analyst. Most models assume that a reservoir is homogeneous (dual porosity excluded, where the dual porosity flow within each layer can be modeled either as pseudo-steady state or transient interporosity flow). There is no single reservoir that is actually homogeneous in nature, but many reservoirs behave as homogeneous reservoirs.

Vertical model

The vertical model simulates the pressure response in a vertical well within a rectangular-shaped reservoir with homogeneous or dual-porosity characteristics. Note that the well may be at any location within the reservoir, and that the reservoir for the vertical model has no-flow boundaries. During very early times, the cylindrical source solution is used, which is followed by the Green's function solutions (Gringarten and Ramey, 1973). No-flow boundaries are modeled using the method of images. The result is superposed in time based on the rate history provided.

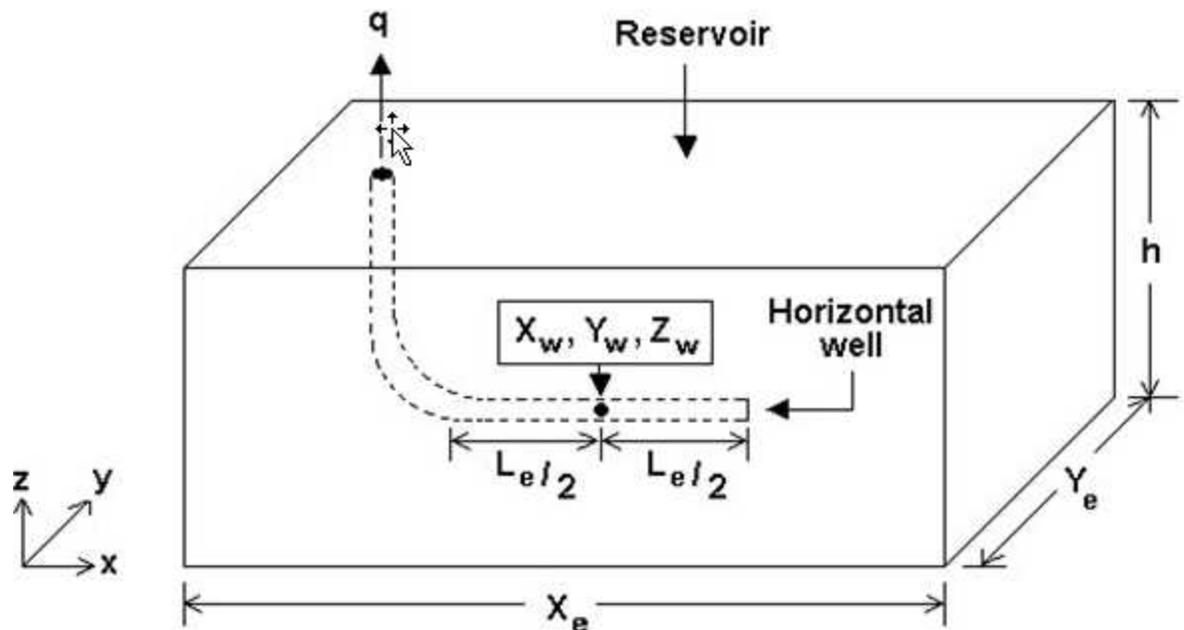
Vertical with fracture model

The fracture model simulates the pressure response in a vertical well intercepted by an infinite-conductivity vertical fracture within a rectangular-shaped reservoir with homogeneous or dual-porosity characteristics (see the figure below). Note that the well may be at any location within the reservoir, and that the reservoir for the fracture model has no-flow boundaries. During very early times, the cylindrical source solution is used, which is followed by Green's function solutions. The Green's function solution, as developed by Thompson et al. (1991), is used with slight modifications to simulate an infinite-conductivity vertical fracture. No-flow boundaries are modeled using the method of images. The result is superposed in time based on the rate history provided.



Horizontal model

The horizontal model simulates the pressure response in a horizontal well within a rectangular-shaped reservoir with anisotropic heterogeneities (that is, differences in permeability in the x, y, and z directions), or dual-porosity characteristics. The anisotropy is handled using a conformal mapping procedure that adjusts the boundary sizes accordingly to mimic the effect of increased or decreased permeability in each direction. The horizontal well is oriented in the x-direction, and may be at any location within the reservoir (see the figure below) and supports no-flow boundaries.

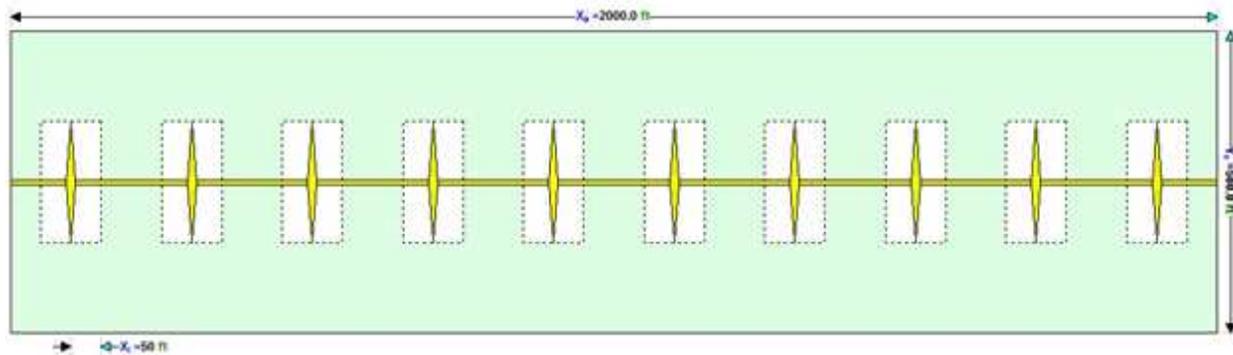


Note that the effective wellbore length (L_e) defines the wellbore area open to fluid flow. The cylindrical source solution is used at very early times, which is followed by Green's function solutions for horizontal wells, as developed by [Thompson et al. \(1991\)](#). No-flow boundaries are modeled using the method of images. The result is superposed in time based on the rate history provided. The following flow regimes can be handled by this model:

- Wellbore storage
- Vertical radial flow
- Linear horizontal flow
- Elliptical flow
- Horizontal radial flow
- Boundary effects
- Pseudo-steady state flow

Horizontal multifrac enhanced fracture region model

This model is a rectangular reservoir model consisting of a non-contributing horizontal well and transverse fractures. This model assumes that all the fractures are uniformly spaced with equal half-fracture length. (The reservoir can extend beyond the fracture tips.) This model has an improved effective permeability region around each fracture, and you can specify the distance from the fracture to the permeability boundary (X_1).



This model takes the following linear flow regimes into account:

- linear flow within the fracture (at very early time)
- linear flow within the stimulated region towards the fractures
- linear flow within the non-stimulated regions towards the stimulated region
- linear flow within the non-stimulated region towards the wellbore

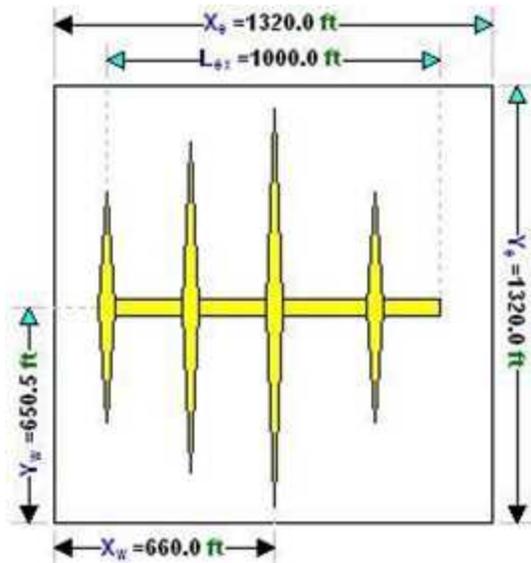
Note: A detailed description of the model is given by [Stalgorova and Mattar \(2012\)](#).

Asymmetrical horizontal multifrac model

The asymmetrical horizontal multifrac model is a homogeneous, single-phase, rectangular reservoir model consisting of a horizontal wellbore and transverse fractures. The horizontal multifrac solution is created through superposition of individual infinite conductivity fracture solutions in space.

You can specify the reservoir dimensions and well position, provided the entire wellbore and all fractures fit within the reservoir boundaries. In addition, each fracture can be situated anywhere along the horizontal wellbore and configured to have a unique fracture half-length and conductivity. Thus, it is possible to model the combined effects of the horizontal wellbore and multiple fractures as well as the transition into middle-time flow regimes and boundary-dominated flow for any number of different geometrical configurations. Depending on the configuration, pseudo-radial flow can be observed with this model.

Damage skin is applied along the length of the horizontal wellbore and a turbulence factor may be specified.

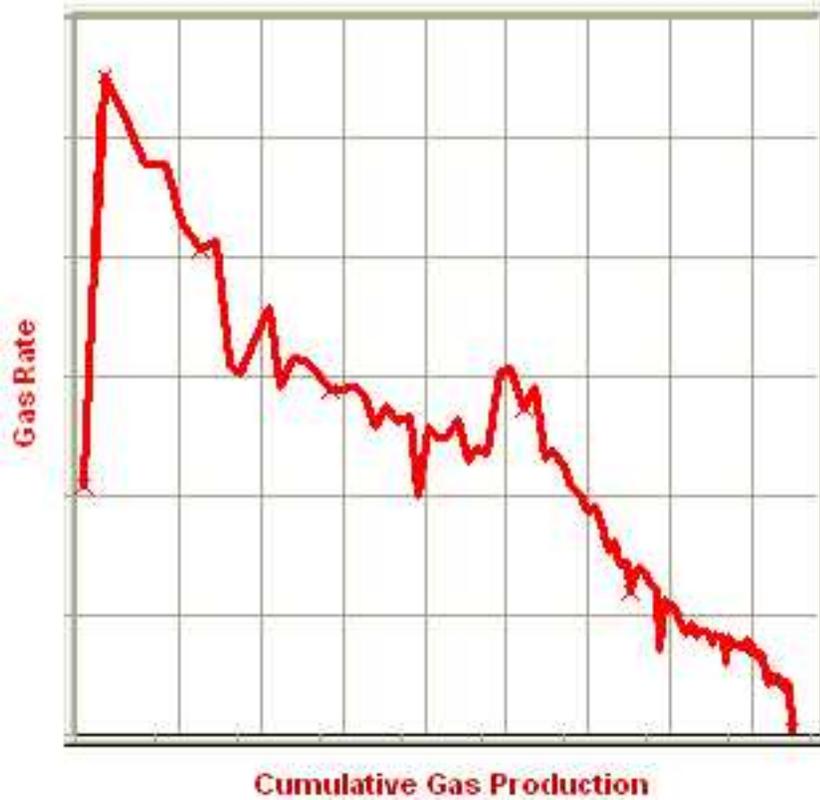


Decline analysis theory

Conceptual definition: decline analysis

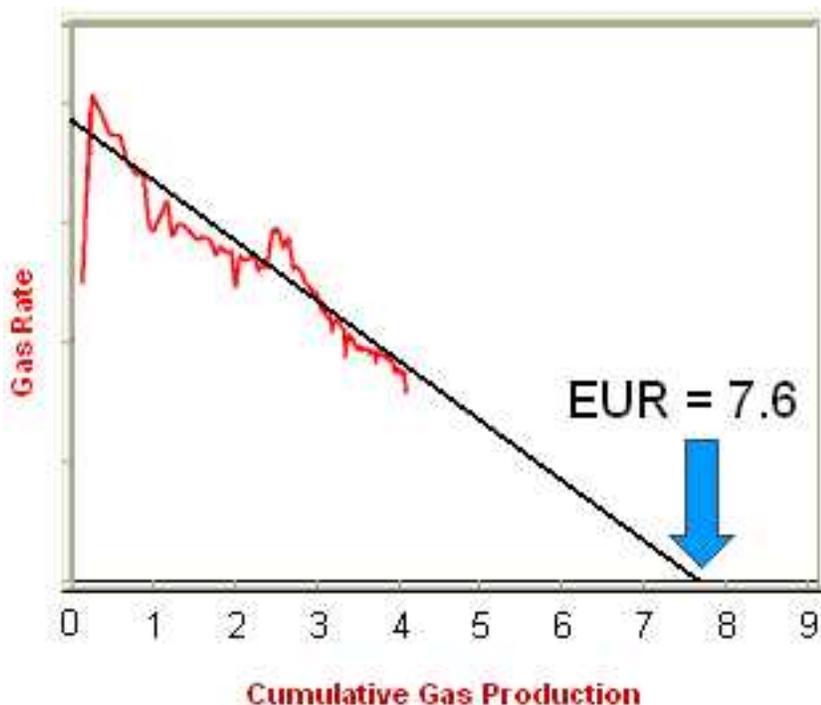
Decline analysis is a reservoir engineering empirical technique that extrapolates trends in the production data from oil and gas wells. The purpose of a decline analysis is to generate a forecast of future production rates, and to determine the expected ultimate recoverable (EUR) reserves.

Figure 1: Rate versus cumulative gas production



Typically, a decline analysis is conducted on a plot of rate versus time, or rate versus cumulative production (as shown in the figure above). The most commonly used trending equations are those first documented by J.J. Arps (1945). The following figure demonstrates a match trend and extrapolation to the EUR.

Figure 2: Rate versus cumulative gas production



Historical background

J.J. Arps was an American geologist who published a mathematical relationship for the rate at which oil production from a single well declines over time (1945). His paper made several references to existing methods and theory about decline analysis. References included Arnold and Anderson (1908), W.W. Cutler (1924), H.N. Marsh (1928), and R. E. Allen (1931).

Many contemporary published papers have tried to investigate or modify the Arps decline based on theoretical derivations. However, after 70 years, the original method is still widely in use.

Practical decline analysis: key points

All production can be characterized as having an initial transient flow period followed by a boundary-dominated-flow period. During the transient period, the reservoir pressure at the flow boundary remains constant at the initial reservoir pressure, and the flow boundary moves outward from the well through the reservoir. This portion of a well's flow is characterized by very high decline rates. When the flow boundary reaches an actual reservoir boundary, or meets with a flow boundary of another well, the reservoir pressure begins to decline, and the well enters the boundary-dominated-flow period. It is in this period that traditional decline methods (that is, Arps) can be used.

The transient flow period can last for time periods from several minutes to several years, depending upon permeability and the areal extent of the reservoir. For most conventional production, the transient flow period ends after a few days. Tighter reservoirs that have permeability in the 0.5 to 1.0 mD range can have transient periods that last several months. Reservoirs that have even lower permeabilities that require extensive fracture networks can have transient periods that could last for several years.

Once a well has achieved boundary-dominated flow, another important consideration is the sandface flowing pressure. For the period of production included in the decline analysis, the sandface flowing pressure must be relatively constant before a reliable set of decline parameters can be extracted. Factors that affect sandface flowing pressure are rate-controlled wells, changing wellhead backpressure, changing wellbore configurations, and liquid loading.

Decline theory

The theory of all decline curve analysis begins with the concept of the nominal (instantaneous) decline rate (a), which is defined as the fractional change in rate per unit time:

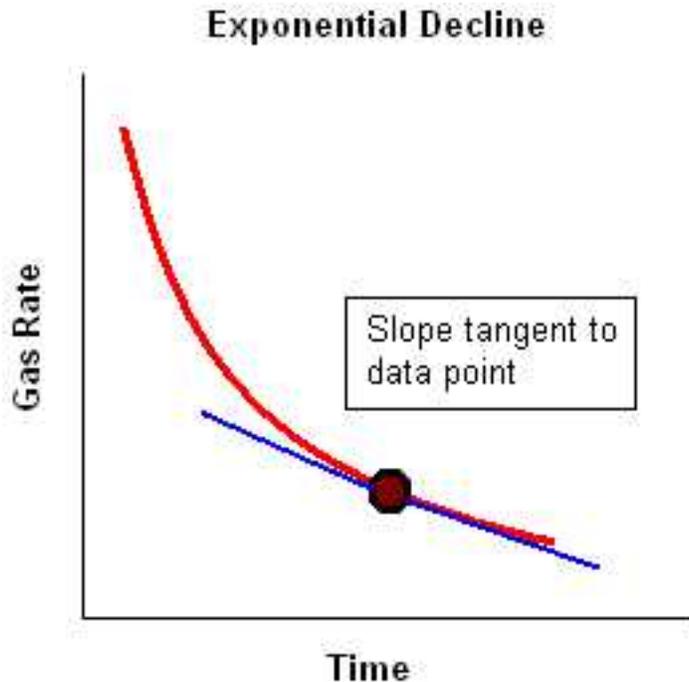
$$a = \frac{(\Delta q/q)}{\Delta t} = \frac{1}{q} \frac{\Delta q}{\Delta t}$$

Another way of representing the decline rate is based on rate (q), and the decline exponent constant, b .

$$a = kq^b$$

When production is plotted as flow rate vs. time, the nominal decline rate is equal to the slope at a point in time divided by the rate at that point.

Figure 3



The behavior of the production data can be characterized based on the way in which the nominal decline rate varies with rate, based on the value of the decline exponent constant b .

- **Exponential** — $b = 0$
- **Hyperbolic** — b is a value other than 0 or 1
- **Harmonic** — $b = 1$

Exponential

For the exponential case, $b = 0$. The decline rate can be shown as:

$$a = kq^0$$

Where k is a constant equal to a / q^b at initial conditions:

$$k = \frac{a_i}{a_i^0} = a_i = a$$

As the decline rate remains constant, the integration of the equation for decline rate results in:

$$a = kq^b = - \frac{1}{q} \frac{dq}{dt}$$

$$\int_0^t a dt = \int_{q_i}^q - \frac{dq}{q}$$

$$-a t = \ln \frac{q}{q_i}$$

$$q = q_i e^{(-at)}$$

Therefore, a plot of flow rate vs. time, with rate set to a logarithmic axis, results in a straight line.

The cumulative production is defined as:

$$Q = \int_0^t q dt$$

$$Q = \int_0^t q_i e^{(-at)} dt$$

$$Q = \frac{q_i - q_i e^{(-at)}}{a}$$

$$Q = \frac{q_i - q}{a}$$

Therefore, a plot of flow rate vs. cumulative production results in a straight line.

Hyperbolic

For the hyperbolic case, b is equal to any number between zero and one. The decline rate can be shown as:

$$a = kq^b$$

$$a \propto q^b$$

Where k is a constant equal to a / q^b at initial conditions:

$$k = \frac{a_i}{q_i^b}$$

As the decline rate is not constant, the substitution and integration of the equation for decline rate results in:

$$a = kq^b = -\frac{1}{q} \frac{dq}{dt}$$

Substituting

$$k = \frac{a_i}{q_i^b} :$$

$$a = \frac{a_i}{k_i} q^1 = -\frac{1}{q} \frac{dq}{dt}$$

$$\int_0^t \frac{a_i}{q_i} dt = \int_{q_i}^q -\frac{dq}{q^2}$$

$$\int_0^t \frac{a_i}{q_i} dt = \int_{q_i}^q -\frac{dq}{q^{(b+1)}}$$

$$\frac{a_i}{q_i^b} t = \frac{1}{b} (q^{-b} - q_i^{-b})$$

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

The cumulative production is defined as:

$$Q = \int_0^t q dt$$

$$Q = \int_0^t \frac{q_i}{(1 + ba_i t)^{\left(\frac{1}{b}\right)}} dt$$

$$Q = \frac{q_i}{a_i(1-b)} \left[1 - (1 + ba_i t)^{\left(1 - \frac{1}{b}\right)} \right]$$

Substituting

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

$$Q = \frac{q_i}{a_i(1-b)} \left[1 - \left(\frac{q_i}{q}\right)^{(b-1)} \right]$$

$$Q = \frac{q_i^b}{a_i(1-b)} \left(q_i^{(1-b)} - q^{(1-b)} \right)$$

Note that neither a plot of flow rate vs. time nor flow rate vs. cumulative production results in a linear relation (regardless of whether rate is set to a Cartesian or logarithmic axis).

Harmonic

The harmonic case is a special case of the above hyperbolic case, where b is equal to one. The decline rate can be shown as:

$$a = kq^1$$

Where k is a constant equal to a / q^b at initial conditions:

$$k = \frac{a_i}{q_i^{(1)}} = \frac{a_i}{q_i}$$

As the decline rate is not constant, the substitution and integration of the equation for decline rate results in:

$$a = kq^b = -\frac{1}{q} \frac{dq}{dt}$$

Substituting

$$k = \frac{a_i}{q_i} :$$

$$a = \frac{a_i}{q_i} q^{(1)} = -\frac{1}{q} \frac{dq}{dt}$$

$$\int_0^t \frac{a_i}{q_i} dt = \int_{q_i}^q -\frac{dq}{q^2}$$

$$\frac{a_i}{q_i} t = -\left[\left(-\frac{1}{q}\right) - \left(-\frac{1}{q_i}\right)\right]$$

$$q = \frac{q_i}{(1 + a_i t)}$$

The cumulative production is defined as:

$$Q = \int_0^t q dt$$

$$Q = \int_0^t \frac{q_i}{(1 + a_i t)} dt$$

Substituting

$$\frac{q_i}{q} = (1 + a_i t) :$$

$$Q = \frac{q_i}{a_i} \ln \left(\frac{q_i}{q} \right)$$

Note that a plot of flow rate vs. time does not result in a linear relation (regardless of whether rate is set to a Cartesian or logarithmic axis). A plot of flow rate vs. cumulative production, with rate set to a logarithmic axis, results in a straight line.

Exponential decline rate: nominal vs. effective

When production follows an exponential decline, there are two different ways of defining the decline rate: nominal and effective.

The first is the nominal decline rate, represented by the symbol "a". The nominal decline rate is defined as:

$$a = \frac{\ln \left(\frac{q_1}{q_2} \right)}{t_2 - t_1} = \frac{\ln \left(\frac{q_1}{q} \right)}{t}$$

The nominal decline rate is used to calculate the rate decline at a specific time. For a given time, the equation for rate using nominal decline is:

$$q_2 = q_1 e^{(-a(t_2 - t_1))}$$

$$q = q_1 e^{(-a t)}$$

The second is the effective decline rate, represented by the symbol "d". The effective decline rate, for a particular time period (typically one year), is defined as:

$$d = \frac{(q_1 - q_2)}{q_1} = \frac{(q_i - q)}{q_i}$$

The effective decline rate is used to calculate the rate decline for particular time periods. For one timestep, the equation for rate using effective decline is:

$$q_2 = q_1 (1 - d)$$

$$q = q_i (1 - d)$$

Note that the time interval is included in the equation for rate using effective decline, but is explicitly stated in the equation for rate using nominal decline.

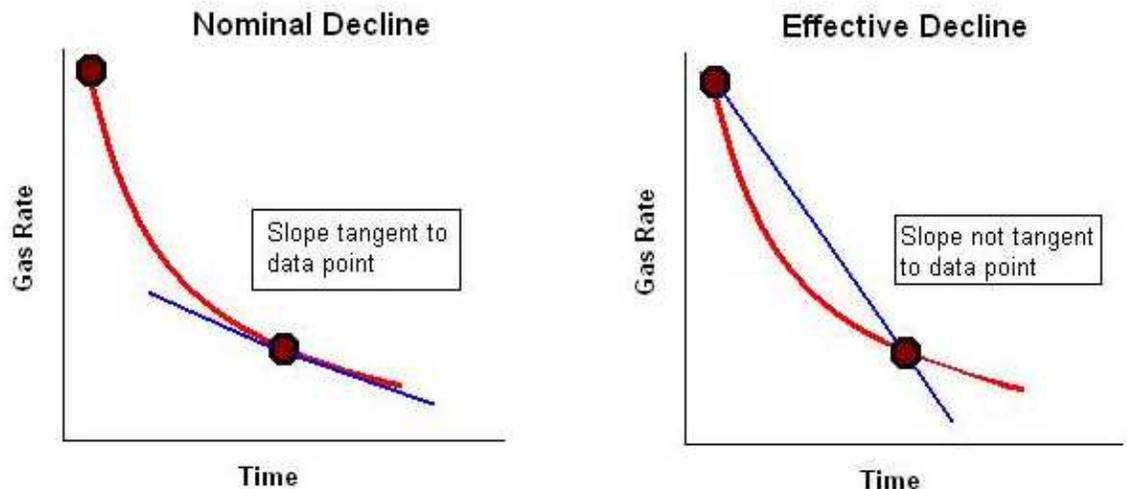
Although the equations for nominal and effective decline rates are different from one another, there is a relationship that gives the same answer for q_2 provided the time intervals between q_1 and q_2 are the same. The relationship between the two is given by:

$$a = -\ln(1 - d)$$

Note: The above equation is only valid for the exponential equations.

The difference between the two decline rates is shown below. In effect, the nominal decline rate is related to the instantaneous slope of the line, whereas the effective decline rate derives from the chord segment approximating that slope. Also, the rate by which the slope is divided is different – instantaneous rate (q) is used in the case of nominal decline, whereas the preceding rate (q_1) is used in the case of effective decline.

Figure 4: Comparison of Nominal Decline and Effective Decline



The effective decline rate typically arises when dealing with flow-rate data in tabular rather than graphical format. The difference between the nominal and effective decline rates is very small

when the nominal decline rate is small, but as the nominal decline rate gets larger, the difference between the two increases. Therefore, it is important to use these values correctly.

Modified hyperbolic decline

Extrapolation of hyperbolic declines over long periods of time frequently results in unrealistically high reserves. To avoid this problem, it has been suggested that at some point in time the hyperbolic decline be converted into an exponential decline (Robertson). Thus, assume that for a particular example, the decline rate starts at 30% and decreases through time in a hyperbolic manner. When it reaches a specified value, 10% for example, the hyperbolic decline can be converted to an exponential decline, and the forecast continued using the exponential decline rate of 10%.

Limited decline rate

The limited decline rate begins as a hyperbolic decline curve and transitions into an exponential decline curve at a specified limiting effective decline rate, d_{lim} . The limiting effective decline rate is converted to a limiting nominal decline rate, a_{lim} , and the following rate – time equations are applied in the analysis:

$$\text{At } d > d_{lim} : q = \frac{q_i}{(1 + ba_i t)^{\left(\frac{1}{b}\right)}}$$

$$\text{At } d \leq d_{lim} : q = q_{lim} e^{(-a_{lim}(t - t_{lim}))}$$

where:

$$q_{lim} = q_i \left(\frac{a_{lim}}{a_i} \right)^{\left(\frac{1}{b}\right)}$$

$$t_{lim} = \frac{\left(\frac{q_i}{q_{lim}} \right)^b - 1}{b a_i}$$

The limited decline rate can also be expressed as rate – cumulative production using the following equations.

For $b > 1$:

$$\text{At } d > d_{\text{lim}} : Q = \frac{q_i^b}{a_i(1-b)} \left(q_i^{(1-b)} - q^{(1-b)} \right)$$

$$\text{At } d \leq d_{\text{lim}} : Q = \frac{q_i^b}{a_i(1-b)} \left(q_i^{(1-b)} - q_{\text{lim}}^{(1-b)} \right) + \frac{q_{\text{lim}} - q}{a_{\text{lim}}}$$

For b = 1:

$$\text{At } d > d_{\text{lim}} : Q = \frac{q_i}{a_i} \ln \left(\frac{q_i}{q} \right)$$

$$\text{At } d \leq d_{\text{lim}} : Q = \frac{q_i}{a_i} \ln \left(\frac{q_i}{q_{\text{lim}}} \right) + \frac{q_{\text{lim}} - q}{a_{\text{lim}}}$$

Values of b > 1

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

A value of b = 0 corresponds to exponential decline; values of b > 0 and < 1 correspond to hyperbolic decline; and a value of b = 1 corresponds to harmonic decline. Values of b > 1 are not consistent with decline curve theory, but they are sometimes encountered, and their meaning is explained below.

Decline curve analysis is based on empirical observations of production rate decline, and not on theoretical derivations. Attempts to explain the observed behavior using the theory of flow in porous media led to the fact that these empirically observed declines are related to boundary-dominated flow. When a well is placed on production, there is transient flow initially. Eventually, all of the reservoir boundaries are felt, and it is only after this time that decline curve analysis becomes applicable. During boundary-dominated flow, the value of "b" lies in the range of 0 to 1, depending on the reservoir boundary conditions and the recovery mechanism.

Occasionally, decline curves with values of b > 1 are encountered. Below are some reasons that have been presented to explain this:

- The interpretation is wrong, and another value of $b < 1$ fits the data.
- The data is still in transient flow and has not reached boundary-dominated flow.
- Gentry and McCray (1978), using numerical simulation showed that reservoir layering can cause values of $b > 1$.
- Bailey (1982) showed that some fractured gas wells exhibit values of $b > 1$, sometimes as high as 3.5.

Arps production decline equation summary

Type	Exponential Decline	Hyperbolic Decline	Harmonic Decline
	Decline is constant $b=0$	Decline is proportional to a fractional power (b) of the production rate $0 < b < 1$	Decline is proportional to production rate $b = 1$
$d_i \rightarrow$	$a_i d_i = -\ln(1 - a_i d_i)$	$a_i d_i = \frac{1}{b} \left[(1 - d_i)^{-b} - 1 \right]$	$a_i = \frac{d_i}{1 - d_i}$
$a_i \rightarrow$	$d_i = 1 - e^{-a_i t}$	$d_i = 1 - (1 + b a_i t)^{-\frac{1}{b}}$	$d_i = \frac{a_i}{1 + a_i t}$
$a(t)$	$a = a_i$	$a = a_i (1 + b a_i \Delta t)^{-1}$	$a = a_i (1 + a_i \Delta t)^{-1}$
Rate-Time	$q = q_i e^{-a_i \Delta t}$	$q = \frac{q_i}{(1 + b a_i \Delta t)^{\left(\frac{1}{b}\right)}}$	$q = \frac{q_i}{(1 + a_i \Delta t)}$
Rate-Cumulative	$Q = \frac{q_i - q}{a}$ $q = q_i - Q a$	$Q = \frac{q_i^b}{a_i(1-b)} \left(q_i^{(1-b)} - q^{(1-b)} \right)$ $q^{(1-b)} = q_i^{(1-b)} - \frac{Q a_i(1-b)}{q_i^b}$	$Q = \frac{q_i}{a_i} \ln \left(\frac{q_i}{q} \right)$ $q = q_i e^{\left(\frac{-Q a_i}{q_i}\right)}$

Type	Exponential Decline	Hyperbolic Decline	Harmonic Decline
EUR	$Q_f = Q_i + \left[\frac{q_i - q_f}{a} \right]$	$Q_f = Q_i + \left[\frac{q_i^b}{a_i(1-b)} \right] \left(q_i^{(1-b)} - Q_{ff}^{(1-b)} \right) Q_i + \left[\frac{q_i}{a_i} \ln \left(\frac{q_i}{q_f} \right) \right]$	

Goodness of fit

Whenever the decline curve is created to approximate production data, you may want a quantitative way to evaluate how good the fit is. There are various metrics that can be used to estimate goodness of fit. In Harmony Enterprise, R² is reported (this statistic is also known as the coefficient of determination).

R² is calculated using the following equations:

For decline curves created on the q vs t plot:

$$R_{\log q \text{ vs. } t}^2 = 1 - \frac{\sum_i (\log q_{i,p} - \log q_{i,c})^2}{\sum_i (\log q_{i,p} - \overline{\log q})^2}$$

For decline curves created on the q vs Cum plot:

$$R_{q \text{ vs. } Q}^2 = 1 - \frac{\sum_i (q_{i,p} - q_{i,c})^2}{\sum_i (q_{i,p} - \bar{q})^2}$$

where:

- i: is the index of summation, and summation is done for all data points after the analysis start date
- q_{i,p}: is the i-th rate (based on given production data)
- q_{i,c}: is the i-th rate (based on decline-curve approximation)
- \bar{q} : is the average for all rates q_{i,p} used in calculations
- $\overline{\log q}$: is the average for all $\log q_{i,p}$ used in calculations

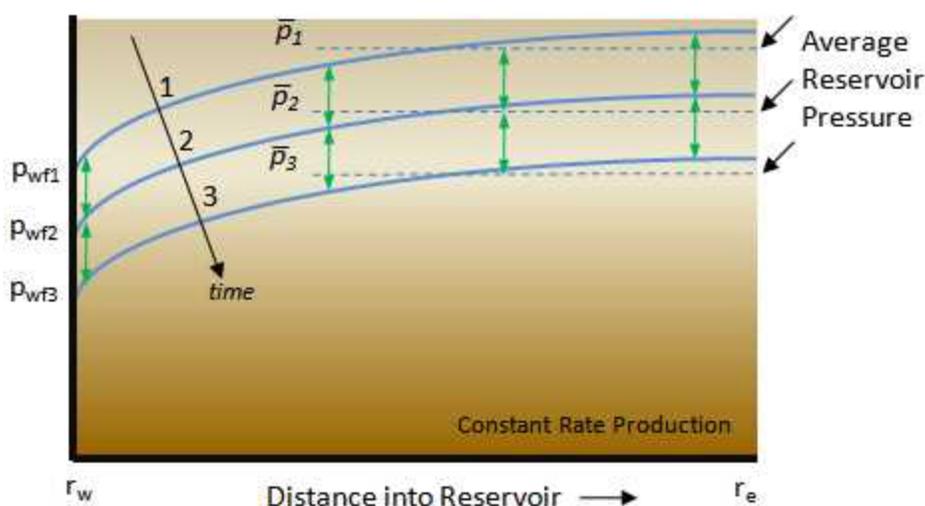
Note: The closer R² is to 1, the better the fit.

Flowing material balance (FMB) theory

The determination of reserves is a fundamental calculation in reservoir engineering. The material balance method uses actual reservoir performance data, and therefore is generally accepted as the most accurate procedure for estimating original hydrocarbons-in-place. In order to generate a traditional material balance plot, the well is shut in at several points during its producing life to obtain the average reservoir pressure. However, this is sometimes impractical, and usually the duration of the shut-in is often not long enough to obtain an accurate measurement. A **FMB** uses the concept of boundary-dominated flow or pseudo-steady state flow, as well as flowing pressures and rates, to calculate original hydrocarbons-in-place.

Pseudo-steady state

The flow of hydrocarbons through a porous medium can be divided into transient and boundary-dominated flow periods. When a well has reached boundary-dominated flow, its behavior is governed by the pseudo-steady state equations. When a reservoir is in pseudo-steady state flow and the flow rate is constant, the pressure at all locations in the reservoir declines at the same rate. The figure below depicts pressures in the reservoir at all locations when the wellbore is located at the left, and the exterior boundary of the reservoir is located at the right. Each of the lines, one, two, and three, represents the pseudo-steady state pressure in the reservoir when the well is flowing at a constant rate. The pressure decline from "time one" to "time two" is the same throughout the reservoir as the curves are parallel.



The traditional material balance method shuts in the well several times during the productive life of the reservoir, and lets the pressure stabilize to an average pressure p_1 . Similarly, the pressure

profile in the reservoir at later times would result in shut-in average reservoir pressures of p_2 and p_3 . It is evident that the drop in pressure from p_1 to p_2 to p_3 is the same as the drop in pressure at any selected point along curves one, two, or three. A convenient point for analysis could be at the wellbore. Remembering that curves one, two, and three represent a flowing well, it is evident that a plot of the flowing wellbore pressure (p_{wf1} , p_{wf2} , p_{wf3}) should be parallel to a plot of the average reservoir pressure (p_1 , p_2 , p_3).

In a flowing situation, the average reservoir pressure clearly cannot be measured. However, as demonstrated above, in a stabilized-flow situation, there is very close connectivity between well-flowing pressures, which can be measured, and the average reservoir pressure. The pressure drop measured at the wellbore while the well is flowing at a *constant* rate is the same as the pressure drop that is observed anywhere in the reservoir, including the location that represents average reservoir pressure. This is *only* true if pseudo-steady state conditions are present, meaning that all boundaries have been reached, and the rate of withdrawal is constant for the period of time when p_{wf1} through p_{wf3} were measured.

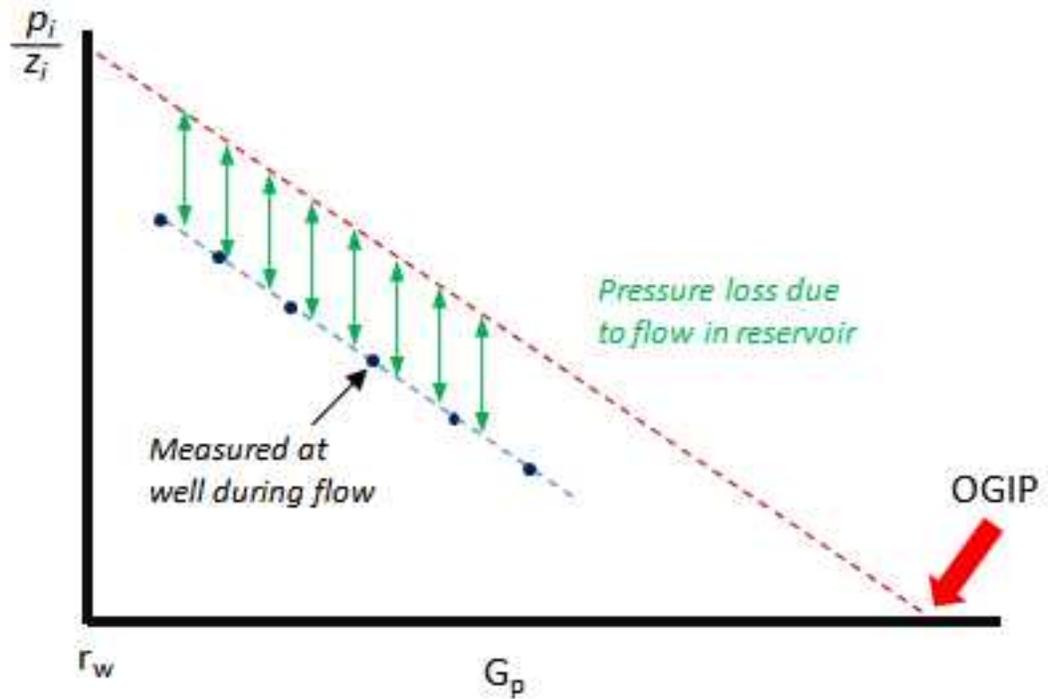
Gas

For gas reserves, the material balance p/z plot is a very useful tool for estimating original gas-in-place (OGIP). The conventional p/z plot uses the extrapolated straight-line trend of measured shut-in pressures to predict OGIP. The same can be done with flowing pressures, provided that the pseudo-steady state assumption is valid (that is, constant rate boundary-dominated flow). For gas, the pseudo-steady state equation for a vertical well in the center of a circular reservoir is as follows:

$$\Delta p_p = p_{pi} - p_{pwf} = \frac{2qp_i t_a}{(\mu c_t Z)_i G_i} + \frac{1.147 \cdot 10^6 T}{k h} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

Furthermore, the pressure decline illustration above shows that a material balance plot of flowing wellbore pressures should be parallel to the material balance plot using the average static reservoir pressure. This procedure, shown below, consists of a plot of p_{wf} / Z , where p_{wf} is the flowing sandface pressure at the wellbore vs. cumulative production. A straight line drawn through the flowing sandface pressure data and then extrapolated parallel from the initial reservoir pressure gives the OGIP.

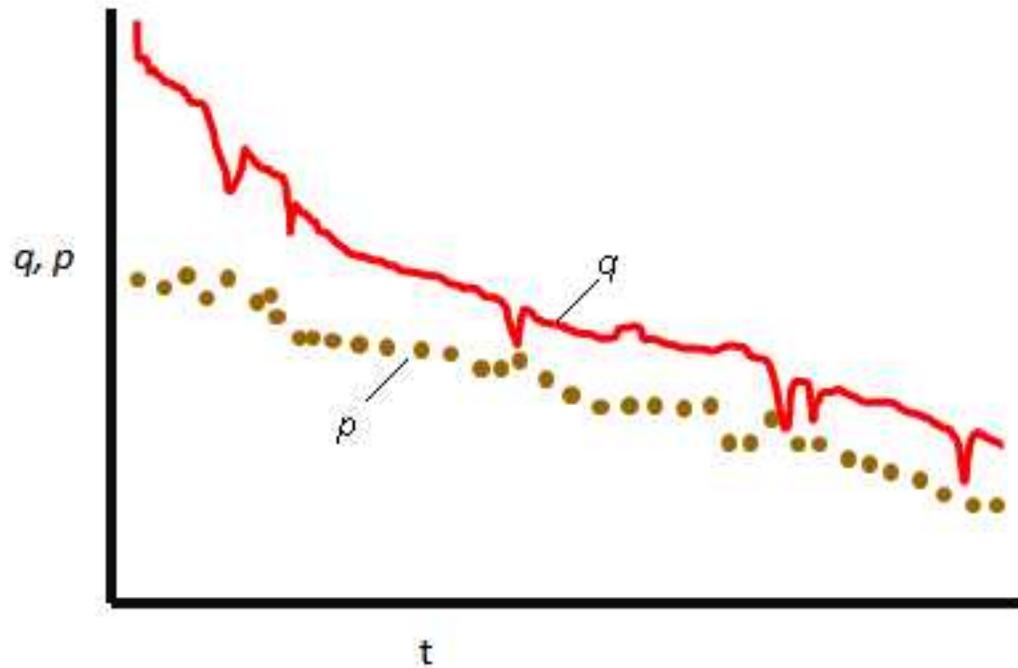
Basically this means that the slope of the resulting best-fit line should be the same as the slope of the conventional p/z line, but shifted upwards, so that it falls through the initial p/z point. This is the flowing gas material balance. Therefore, using flowing pressures and rates, a material balance analysis can be conducted without shutting in the well.



This technique can use either flowing sandface pressures or flowing surface pressures. However, when using surface pressures, the line drawn parallel to the data must pass through the initial "wellhead" pressure, not the initial "reservoir" pressure.

Variable rate flowing p/Z^{}**

Most gas wells do not have extended periods of constant-rate production. Thus the above concepts cannot be directly applied. A typical gas well may have a production profile as shown below.



With the above profile, we cannot assume a constant pressure difference between average reservoir conditions and flowing conditions. We know that during boundary-dominated flow:

$$\bar{p}_p = p_{pwf} + qb_{pss}$$

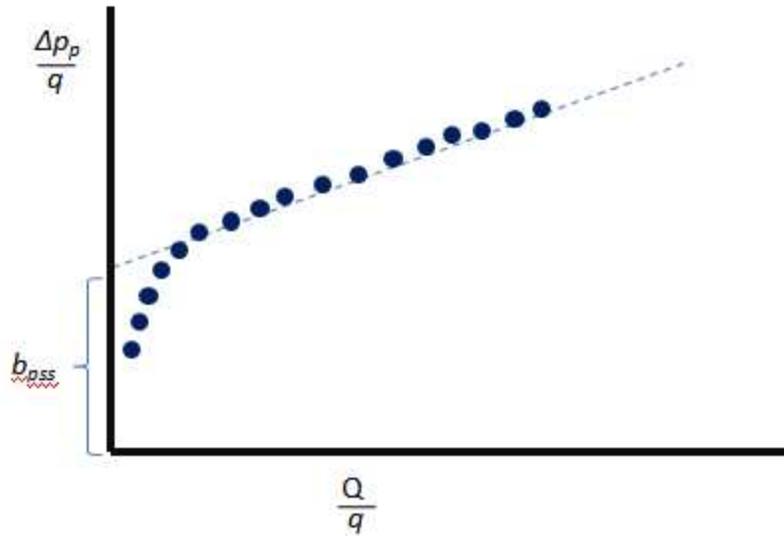
where:

$$b_{pss} = \frac{1.147 \cdot 10^6 T}{k h} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

b_{pss} represents the pressure loss due to the steady-state inflow of gas, and is assumed to be constant over time.

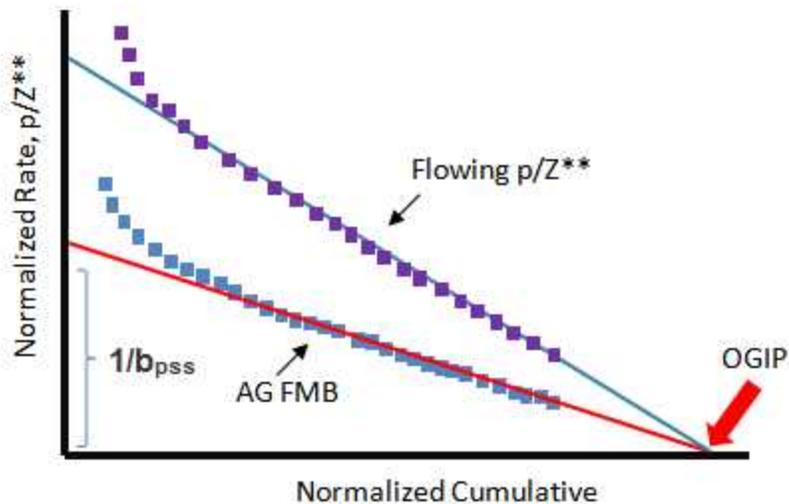
For a variable-rate system, the equation above clearly shows that the difference between reservoir p/z and flowing p/z is not constant, but rather is a function of flow rate. Since the flow rate is known, we need only to determine the value of b_{pss} , using some independent method. Note that the value of b_{pss} did not have to be explicitly determined for the constant rate case because the total value of " $q b_{pss}$ " (the product of flow rate and b_{pss}) was determined graphically.

One way to obtain a reliable estimate of b_{pss} is to plot the production and flowing-pressure data in the following manner:



The straight line portion of this graph represents boundary-dominated flow, and the y-intercept is b_{pss} . This value of b_{pss} may then be used in the above equation to calculate the average reservoir pressure. Note that the value of b_{pss} is always subject to interpretation as it depends on proper identification of the stabilized (straight line) section of the above graph.

Alternatively, b_{pss} can be obtained from the Agarwal-Gardner FMB analysis plot. As shown below, $1/b_{pss}$ is the y-intercept on that plot. Obtaining the value from the best-fit straight line interpretation below, the flowing p/z^{**} values can be calculated.



Agarwal-Gardner normalized rate

An alternative to the flowing p/z plot is the normalized rate / normalized cumulative analysis. The normalized rate approach applies to both oil and gas reservoirs, and works for constant, or variable-rate systems. Its advantage is its flexibility and ease of use. Its primary drawback is that the resulting analysis plot is not as intuitive as that of the flowing p/z.

The procedure is similar to the pseudo-steady state approach, but involves plotting the inverse of the pseudo-steady state equation, so that a declining trend is produced. The normalized rate is plotted against the normalized cumulative. A line is then drawn through the best-fit of the points, and the x-intercept is the OGIP. The governing equation for the straight-line equation for the Agarwal-Gardner analysis is:

$$\frac{q}{\Delta p_p} = \frac{-1}{b_{pss} G_i} \frac{2 q t_{ca} p_i}{(c_t \mu Z)_i (p_{pi} - p_{pwf})} + \frac{1}{b_{pss}}$$

where:

$$Q_m = \frac{G (p_{pi} - \bar{p}_p)}{(p_{pi} - p_{wf})} = \frac{2 q t_{ca} p_i}{(c_t \mu Z)_i (p_{pi} - p_{pwf})}$$

$$\text{Normalized Rate} = \frac{q_g}{p_{pi} - p_{pwf}}$$

and:

$$\text{Normalized Cumulative} = \left(\frac{p_{pi} - \bar{p}_p}{p_{pi} - p_{pwf}} \right) G$$

To calculate the average reservoir pressures, use the general material balance equation below, and first assume a value for OGIP. This is an estimate and can be obtained from volumetrics, modeling, or some other analysis.

$$\frac{P}{Z^{**}} = \frac{p_i}{Z_i^{**}} \left(1 - \frac{G_p}{G} \right)$$

The step-by-step procedure for generating the Agarwal-Gardner analysis for a gas well with varying flow rate is:

1. Convert initial pressure to pseudo-pressure.
2. Convert all flowing pressures to pseudo-pressures.
3. Assume a value for OGIP.
4. Calculate p/z^{**} from the general material balance equations.
5. Using lookup tables, find the corresponding average reservoir pressure.
6. Convert average reservoir pressure to pseudo-pressure.
7. Using the equations above, plot a graph of normalized rate versus normalized cumulative.
8. Draw a straight line through the best-fit of the data points. (The intercept on the x-axis gives OGIP.)
9. Using this new value for OGIP, repeat steps 4-8 until the OGIP converges.

Productivity index

The productivity index of a well is a measure of the production rate achievable under a given draw-down pressure, which is the difference between the average reservoir pressure and the flowing sandface pressure. Defined as the flow rate per unit pressure drop, the productivity index gives an indication of the production potential of a well.

$$PI = \frac{1}{b_{pss}}$$

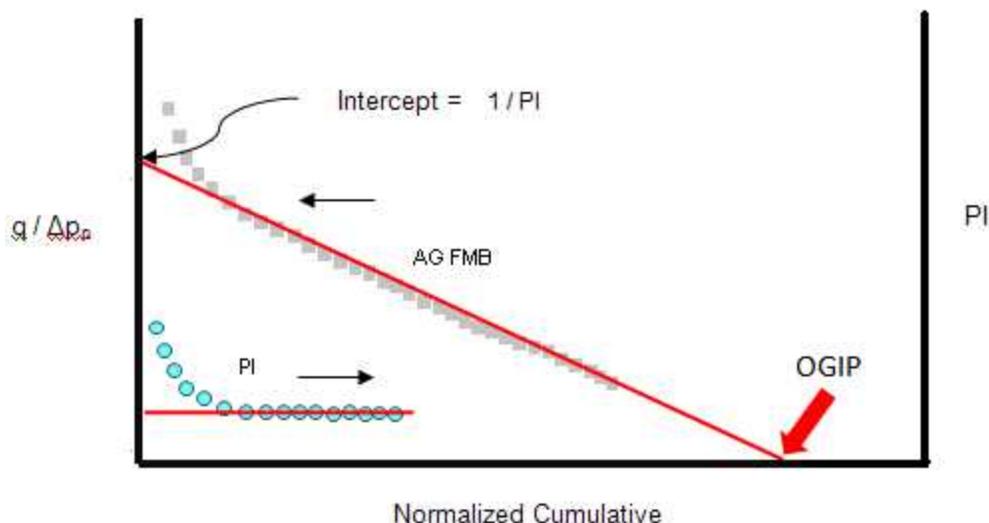
From the pss equation above:

$$\bar{p}_p = p_{pwf} + qb_{pss}$$

therefore:

$$PI = \frac{q_g}{\bar{p}_p - p_{pwf}}$$

From a reservoir point of view, well management primarily depends on the well productivity index, which is in turn dependent on rock and fluid properties. One of the principal causes for the reduction in well productivity is formation damage around the wellbore. For an FMB analysis, when the "correct" OGIP is found, the productivity index dataset should be relatively flat, indicating that the productivity index is not drastically changing over time.



As can be seen above, the productivity index equation is very similar to the traditionally used simplified absolute open flow (AOF) equation, shown below. The major differences being that:

- The productivity index is written rigorously using pseudo-pressures and the AOF equation uses the simpler pressure- squared method.
- The AOF equation introduces the concept of laminar / turbulent flow using the exponent "n".

$$q = c \left(\bar{p}^2 - p_{wf}^2 \right)^n$$

Assuming n = 1:

$$c = \frac{q_g}{\bar{p}^2 - p_{wf}^2}$$

Advanced gas material balance techniques – p/Z**

The graphical simplicity of the conventional p/Z material balance analysis makes it quite popular. Developed for a "volumetric" gas reservoir, it assumes a constant pore volume of gas, and accounts for the energy of gas expansion. However, advanced methods have been developed to account for other sources of energy, such as the effects of formation compressibility, residual fluids expansion, and aquifer support. Furthermore, these methods can also account for other sources of gas storage such as connected reservoirs, or adsorption in coal / shale. The FMB ana-

lysis accounts for all of these effects, if required. The formulation for the calculation of p/Z^{**} is highlighted below:

$$\frac{P}{Z^{**}} = \frac{p_i}{Z_i^{**}} \left(1 - \frac{G_p}{G} \right)$$

where:

$$Z^{**} = \frac{p}{\left[\frac{1}{S_{gi}} \frac{p}{Z} \left(S_{gi} - c_{wip} - c_{ep} - c_d \right) + \frac{p_i}{Z_i} \left(\frac{G}{G_f} - 1 \right) \right] \frac{G_f}{G}}$$

$$\frac{G}{G_f} = 1 + \frac{B_{gi}}{S_{gi}} \frac{\rho_B (1 - a - W_c)}{\phi} \frac{(V_L p_i)}{p_L p_i}$$

and total compressibility is defined as:

$$c_t = \left(c_g \left[S_{gi} - c_{wip} - c_{ep} - c_d \right] - \frac{\partial c_{wip}}{\partial p} - \frac{\partial c_{ep}}{\partial p} - \frac{\partial c_d}{\partial p} \right)$$

The table below outlines the formulations for the total-compressibility equations for all reservoir types.

Definition	Comment
$c_{wip} = \frac{5.615(W_e - W_p B_w)}{\frac{G_f B_{gi}}{S_{gi}}}$	Water-drive reservoir
$\frac{\partial c_{wip}}{\partial p} = \frac{5.615}{\frac{G_f B_{gi}}{S_{gi}}} \frac{\partial W_e}{\partial p}$	
$c_{ep} = (c_f + c_w S_{wi} + c_o S_{oi}) (p_i - p) = c_e (p_i - p)$	$c_o, c_w,$ and c_f are constant
$\frac{\partial c_{ep}}{\partial p} = - \left[c_f \left(1 - c_f (p_i - p) \right) + S_{wi} c_w \left(1 + c_w (p_i - p) \right) + S_{oi} c_o \left(1 + c_o (p_i - p) \right) \right]$	c_{ep} is the approximate form

Definition	Comment
$c_{ep} = \left(1 - e^{-c_f(p_i - p)}\right) + S_{wi} \left(e^{c_w(p_i - p)} - 1\right) + S_{oi} \left(e^{c_o(p_i - p)} - 1\right)$ $\frac{\partial c_{ep}}{\partial p} = - \left[S_{oi} c_o e^{c_o(p_i - p)} + S_{wi} c_w e^{c_w(p_i - p)} + c_f e^{-c_f(p_i - p)} \right]$	<p>c_o, c_w, and c_f are constant</p> <p>c_{ep} is the simple form</p>
$c_{ep} = \left(1 - e^{-\int_p^{p_i} c_f dp}\right) + S_{wi} \left(e^{\int_p^{p_i} c_w dp} - 1\right) + S_{oi} \left(e^{\int_p^{p_i} c_o dp} - 1\right)$ $\frac{\partial c_{ep}}{\partial p} = \left(c_f e^{-\int_p^{p_i} c_f dp} + S_{wi} c_w e^{\int_p^{p_i} c_w dp} + S_{oi} c_o e^{\int_p^{p_i} c_o dp} \right)$	<p>c_o, c_w, and c_f are pressure-sensitive <i>without</i> matrix shrinkage.</p> <p>c_{ep} is the rigorous form</p>
$c_{ep} = \left(1 - F_\phi(p)\right) + S_{wi} \left(e^{\int_p^{p_i} c_w dp} - 1\right) + S_{oi} \left(e^{\int_p^{p_i} c_o dp} - 1\right)$ $\frac{\partial c_{ep}}{\partial p} = \left(-\frac{d F_\phi(p)}{dp} + S_{wi} c_w e^{\int_p^{p_i} c_w dp} + S_{oi} c_o e^{\int_p^{p_i} c_o dp} \right)$	<p>c_o, c_w, and c_f are pressure-sensitive with matrix shrinkage.</p> <p>c_{ep} is the rigorous form</p>
$c_d = \frac{\rho_B B_g}{\phi} \left(1 - a - m\right) \left(\frac{V_L p_i}{p_L + p_i} - \frac{V_L p}{p_L + p}\right)$ $\frac{\partial c_d}{\partial p} = \frac{\rho_B B_g V_L}{\phi} \left(1 - a - m\right) \left[-c_g \left(\frac{p_i}{p_L + p_i} - \frac{p}{p_L + p}\right) + \left(-\frac{1}{p_L + p} + \frac{p}{(p_L + p)^2}\right) \right]$	<p>Shale gas reservoir</p>

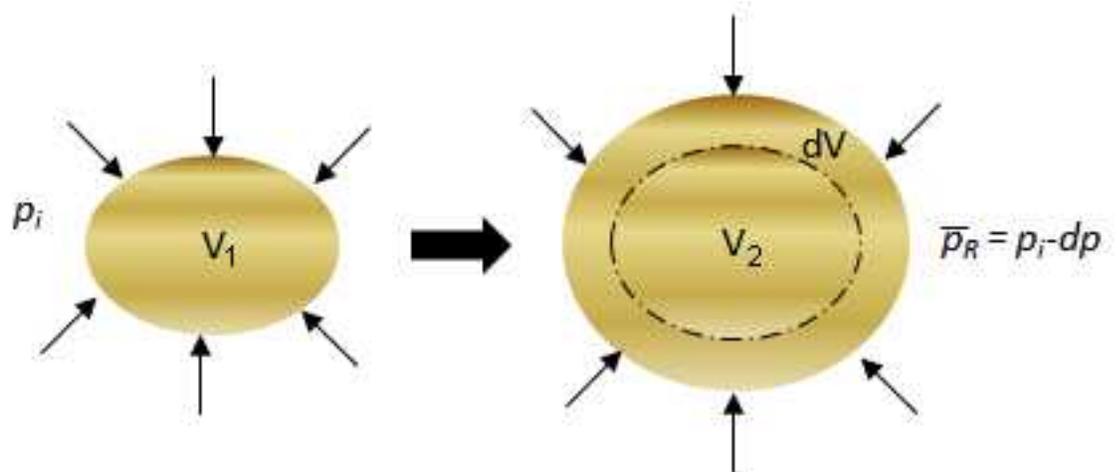
Note: For more information, see Moghadam et al. (2009).

Oil

The basis for the FMB of oil comes from both the definition of compressibility and the steady-state inflow equation. Compressibility is defined as:

$$c = -\frac{1}{V} \frac{\partial V}{\partial p}$$

This equation shows that compressibility is defined as the relative change in fluid volume per unit change in pressure.



The above schematic demonstrates that as pressure is reduced, the fluid expands to occupy a larger volume such that $V_2 > V_1$. However, most reservoirs can reasonably be expected to have a constant pore volume such that $PV_1 = PV_2$. Consequently, as we produce fluid from a reservoir, the remaining fluid in the reservoir expands to fill the pore volume, and so the reservoir pressure is reduced.

Production from an undersaturated* oil reservoir can be visualized as follows:



Pore Volume:

$$\text{Container Volume 1 (PV}_1\text{)} = \text{Container Volume 2 (PV}_2\text{)}$$

Fluid Volume:

$$\text{Fluid Volume 1 (N)} = \text{Fluid Volume 2 (Remaining N) + Extracted Volume (N}_o\text{)}$$

Reservoir Pressure:

$$\text{Initial Reservoir Pressure (p}_i\text{)} = \text{Current Reservoir Pressure (}\bar{p}_R\text{)} + \text{Depletion (N}_p / N * c\text{)}$$

* There is no free gas since the reservoir pressure is greater than the bubble-point pressure of the oil.

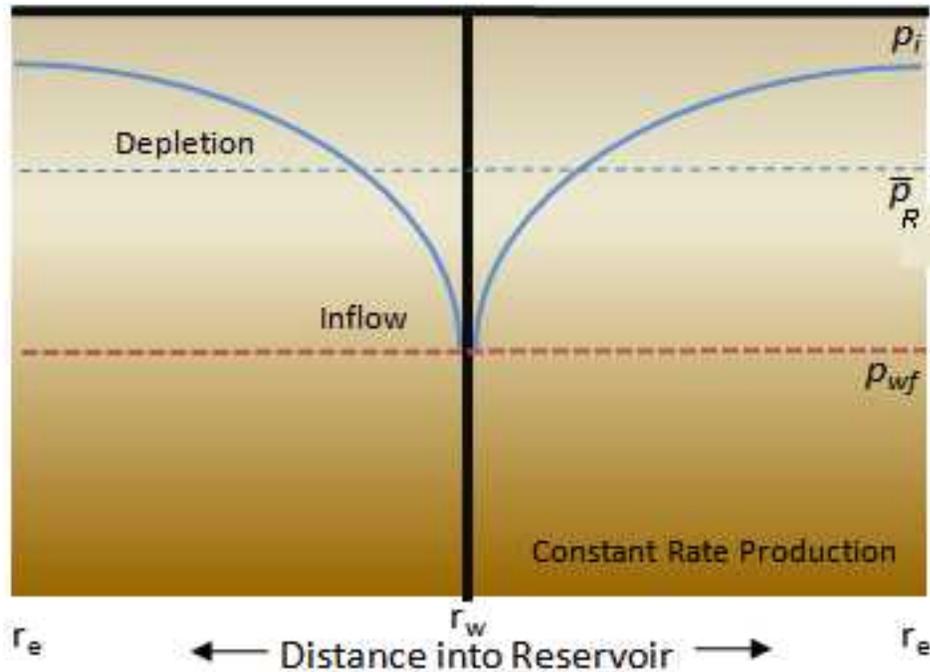
Thus, the change in pressure is the difference between the initial reservoir pressure and the average reservoir pressure, and the change in volume is the produced volume up to that point in time. Knowing that the initial volume is the total oil-in-place, these terms are applied to the compressibility equation.

$$c = \frac{1}{N} \frac{N_p}{(p_i - \bar{p}_R)}$$

Combining the above relationship with the pseudo-steady equation, and then rearranging and substituting for material balance time gives the following:

$$\frac{\Delta p}{q} = \frac{p_i - p_{wf}}{q} = \frac{B_o}{B_{oi}} \frac{S_o N_p}{q c_t N} + \frac{141.2 B_o N_p \mu}{k h} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

The above equation clearly illustrates the relationship between initial pressure, flowing pressure, and rate.



From the figure above, it is apparent that the pseudo-steady state equation is the sum of two distinct pressure-loss components:

Pressure loss due to depletion:

$$p_i - \bar{p}_R = \frac{B_o}{B_{oi}} \frac{S_o q t}{c_t N}$$

Pressure loss due to inflow:

$$\bar{p}_R - p_{wf} = \frac{141.2 B_o \mu q}{k h} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

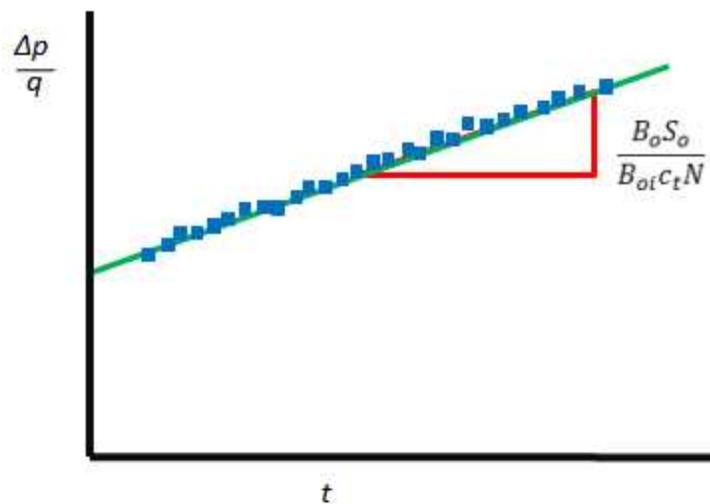
The advantage of the pseudo-steady state formulation is that the average reservoir pressure is eliminated during the addition of pressure loss due to depletion and pressure loss due to inflow, and thus is not explicit in the equation. This is an obvious advantage because the average reservoir pressure is an unknown. Since both terms (pressure loss due to depletion and pressure loss due to inflow) are functions of rate, we can simplify the pseudo-steady state equation as follows:

$$\frac{\Delta p}{q} = \frac{B_o}{B_{oi}} \frac{S_o}{c_t N} t + b_{pss}$$

where:

$$b_{pss} = \frac{141.2 B_o \mu}{k h} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

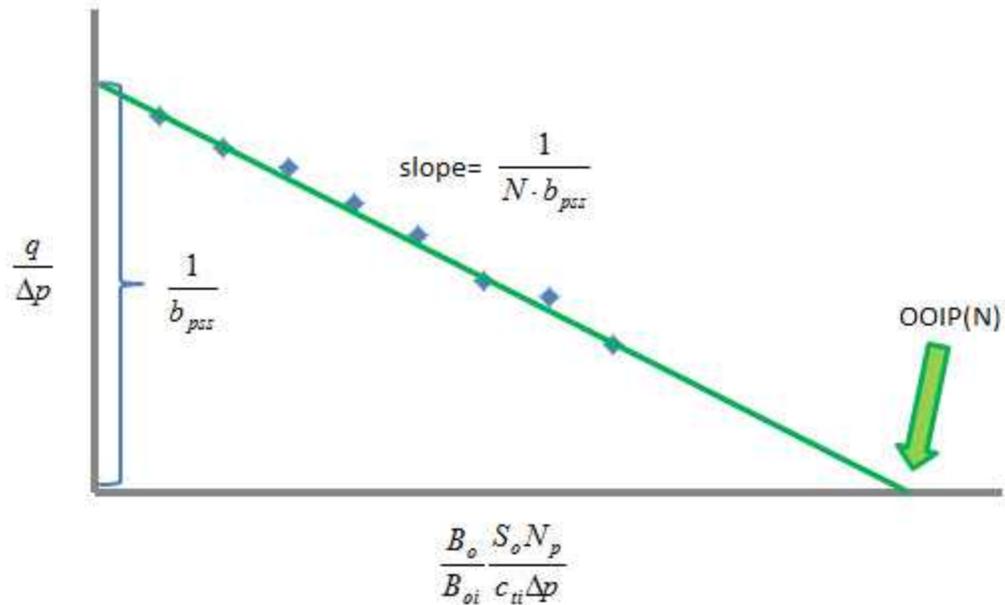
A graph of normalized pressure vs. time produces a straight line, the slope of which provides the original oil-in-place (OOIP). This is the most basic form of FMB, and is directly applicable to under-saturated oil reservoirs. In well testing, this procedure is commonly referred to as a "reservoir limits test".



However, to make it more intuitive and similar to a gas material balance plot, the pseudo-steady state equation above is rearranged to the following:

$$\frac{q}{\Delta p} = \frac{1}{b_{pss}} - \frac{B_o S_o N_p}{B_{oi} c_t N \Delta p b_{pss}}$$

Plotting normalized rate vs. normalized cumulative (similar to the Agarwal-Gardner plot), the following plot is derived, where the x-intercept is equal to the OOIP.



The above equation and associated figure describe the flowing oil material balance analysis for a volumetric circular reservoir.

Static pressure data

If static pressures are available, you can use this data as an independent confirmation of the OOIP. This is an equation describing material balance for an oil reservoir for a simple case (that is, no gas cap, no water production), assuming constant total compressibility:

$$N_p B_o = \frac{N}{S_o} \cdot B_{oi} (p_i - \bar{p}) c_{ti}$$

This equation can be rearranged as:

$$\bar{p} = p_i - \frac{B_o \cdot S_o N_p \cdot p_i}{B_{oi} c_{ti} p_i N}$$

↑
←
→

y-value
x-value

Therefore, plotting average pressure against

$$\text{Adjusted Normalized Oil Cumulative Production} = \frac{B_o S_o N_p}{B_{oi} c_{ti} p_i}$$

should follow a straight line, with the x-intercept of the line being equal to the OOIP.

Accounting for variation in oil properties

The derivation for oil Flowing Material Balance (FMB) given above is valid under the assumption that the variation of oil and rock properties (c_t , B_o , μ_o , and k) with pressure is negligible. That assumption is valid for some cases, but sometimes (for example, for oil with high gas content, or for cases with pressure-dependent rock properties), it is important to accurately account for variations in oil and rock properties.

This is done similarly to Agarwal-Gardner FMB analysis for gas.

Oil pseudo-pressure is defined as:

$$p_{po}(p) = \frac{B_o(p_i) \mu_o(p_i)}{k(p_i)} \int_0^p \frac{k(p)}{B_o(p) \mu_o(p)} dp$$

Total pseudo-pressure drop can then be written in terms of oil pseudo-pressure and can be presented as:

$$\begin{aligned} \Delta p_{po} &= p_{po}(p_i) - p_{po}(p_{wf}) = (p_{po}(p_i) - p_{po}(\bar{p})) + (p_{po}(\bar{p}) - p_{po}(p_{wf})) \\ \text{total} &= \text{due to depletion} + \text{due to Darcy flow} \end{aligned}$$

Under conditions of pseudo-steady state, the pressure drop due to Darcy flow and flow rate are related by:

$$q_o = \text{Constant} \cdot \int_{p_{wf}}^{\bar{p}} \frac{k(p)}{\mu_o(p) B_o(p)} dp$$

Where *Constant* is defined by reservoir and completion geometry, but does not change with pressure. Using rules of integration, this can be rearranged as:

$$q_o = \text{Constant} \cdot \int_{p_{wf}}^{\bar{p}} \frac{k(p)}{\mu_o(p) B_o(p)} dp = \text{Constant} \cdot \left(\int_0^{\bar{p}} \frac{k(p)}{\mu_o(p) B_o(p)} dp - \int_0^{p_{wf}} \frac{k(p)}{\mu_o(p) B_o(p)} dp \right) =$$

$$= \left(\text{Constant} \cdot \frac{k(p_i)}{\mu_o(p_i) B_o(p_i)} \right) \left(p_{po}(\bar{p}) - p_{po}(p_{wf}) \right)$$

Therefore, pressure drop due to Darcy flow in terms of oil pseudo-pressure can be expressed as:

$$p_{po}(\bar{p}) - p_{po}(p_{wf}) = q_o \cdot b'_{pss}$$

Where b'_{pss} does not vary with pressure.

Using this formulation for pressure drop due to Darcy flow, total pressure drop can be presented as:

$$\Delta p_{po} = (p_{po}(p_i) - p_{po}(\bar{p})) + q_o \cdot b'_{pss}$$

Dividing both sides by $\Delta p_{po} b'_{pss}$ and rearranging we get:

$$\frac{q_o}{\Delta p_{po}} = \frac{1}{b'_{pss}} - \left(\frac{p_{po}(p_i) - p_{po}(\bar{p})}{\Delta p_{po}} N \right) \cdot \frac{1}{N b'_{pss}}$$

y value = intercept - x value · slope

(Note that we added N to both the numerator and denominator of the last term.)

This equation is used to create a plot for oil FMB analysis that accounts for variation of oil and formation properties.

The y-values for each data point can be readily calculated based on production data:

$$\text{Oil Normalized Rate} = \frac{q_o}{\Delta p_{po}}$$

To calculate x-values, use an iterative procedure:

1. Estimate a value for oil in place, N_{guess} .

2. Calculate the average reservoir pressure based on N_{guess} , known production data, and using rigorous material-balance calculations.
3. Calculate x-values:

$$\text{Normalized Oil Cumulative Production} = \frac{p_{po}(p_i) - p_{po}(\bar{p})}{\Delta p_{po}} N_{guess}$$

4. Generate an FMB plot (y-values vs. x-values).
5. Draw a straight line through the data points corresponding to boundary-dominated flow (the late portion of the data).
6. The y-intercept of the line equals $1/b'_{pss}$, and the slope of the line equals $1/(Nb'_{pss})$; therefore N can be calculated.
7. Compare the calculated N with N_{guess} . If they are not equal, set the next N_{guess} to the value calculated in step 6, and return to step 1.
8. Iterate until $N = N_{guess}$.

This approach is described by [Stalgorova and Mattar \(2016\)](#).

Permeability calculation

In general, the FMB analysis does not require any assumptions about well and reservoir geometry. However, if you can make an assumption about geometry, reservoir permeability can be calculated based on the productivity index (PI). (PI is defined by the y-intercept of the analyses line.) Currently, permeability calculation is implemented for two types of flow:

- Radial flow — applicable for a vertical well located approximately in the middle of the reservoir.
- Linear flow — applicable for a vertical well with fracture, where the fracture is extended approximately throughout the entire width of the reservoir.

The following equations are used to calculate permeability based on the PI.

Radial flow oil:

$$k = 141.2 \frac{B_o \mu_o}{h} \left(\ln \left(\frac{r_e}{r_w} \right) - 0.75 \right) * PI_{oil}$$

Radial flow gas:

$$k = 1.417 \frac{T}{h} \left(\ln \left(\frac{r_e}{r_w} \right) - 0.75 \right) * PI_{gas}$$

Linear flow oil:

$$k = 141.2 \frac{B_o \mu_o}{h} \left(\frac{2 y_e}{\pi x_e} \right) * PI_{oil}$$

Linear flow gas:

$$k = 1.417 \frac{T}{h} \left(\frac{2 y_e}{\pi x_e} \right) * PI_{gas}$$

In this case, you provide one of the reservoir dimensions (x_e or y_e) and the other dimension is calculated based on the area.

Multiphase flowing material balance (FMB) theory

There is significant research in the field of multiphase FMB, and rate-transient analysis in general, that is ongoing at the University of Calgary, under the direction of Dr. Chris Clarkson. This research has been supported by industry sponsors of the Clarkson-led Tight Oil Consortium, and by NSERC CRD grants held by Clarkson. This partial list of [publications](#) attests to the interest, effort, and success of his team in this field. All the methods have a certain number of assumptions and approximations, and are therefore not exact analytical solutions for all flow conditions. For example, they are not meant to be applicable to “transient flow”, but they are intended for analyzing boundary-dominated flow. Our (IHS Markit) development of Multiphase FMB, implemented in Harmony Enterprise version 2018.1 builds on the work of Dr. Clarkson’s team and extends it. Most of the studies define one two-phase pseudo-pressure for oil, and one for gas. Some define a total pseudo-pressure that combines all three phases.

There are two major components to the FMB methodology: defining an appropriate pseudo-pressure and an appropriate pseudo-time. Sometimes, as in the current implementation, pseudo-time is not visible explicitly, but is couched in expressions that combine the average pseudo-pressure and cumulative production.

Multiphase FMB parallels the single-phase methodology. In simple terms, single-phase FMB was derived for oil (in terms of pressure). Multiphase FMB uses the same format of equations, but

replaces pressure by a pseudo-pressure that accounts for the variations in pressure, volume, and temperature (PVT) properties, saturation changes, relative permeability, and individual flowing phases.

As an introduction, a simplified version of the single-phase FMB formulation is presented below:

(Boundary-dominated flow) fundamental flow equation:

$$p_i - p_{wf} = \frac{qt}{c_t N} + \frac{141.2qB\mu}{kh} \left[\left(\ln \frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

Can be simplified to:

$$p_i - p_{wf} = \frac{qt}{c_t N} + bq$$

$$p_i - p_{wf} = \frac{N_p}{c_t N} + bq$$

Rearranging — divide by b and by $(p_i - p_{wf})$:

$$\frac{q}{(p_i - p_{wf})} = - \frac{N_p}{bc_t N (p_i - p_{wf})} + \frac{1}{b}$$

Material balance equation:

$$p_i - \bar{p}_R = \frac{N_p}{c_t N}$$

Combining these two equations:

$$\frac{q}{(p_i - p_{wf})} = - \frac{(p_i - \bar{p}_R)}{b(p_i - p_{wf})} + \frac{1}{b}$$

Multiplying top and bottom by N:

$$\frac{q}{(p_i - p_{wf})} = -\frac{1}{bN} \left\{ \frac{(p_i - \bar{p}_R)}{(p_i - p_{wf})} N \right\} + \frac{1}{b}$$

This is the **FMB equation** that is represented in the **Agarwal-Gardner (A-G) plot**: Plotting the **left-side** against {...} results in an **x-intercept** of **N** (original-oil-in-place), and a **y-intercept** of **1/b** (Productivity Index).

Multiphase FMB equation

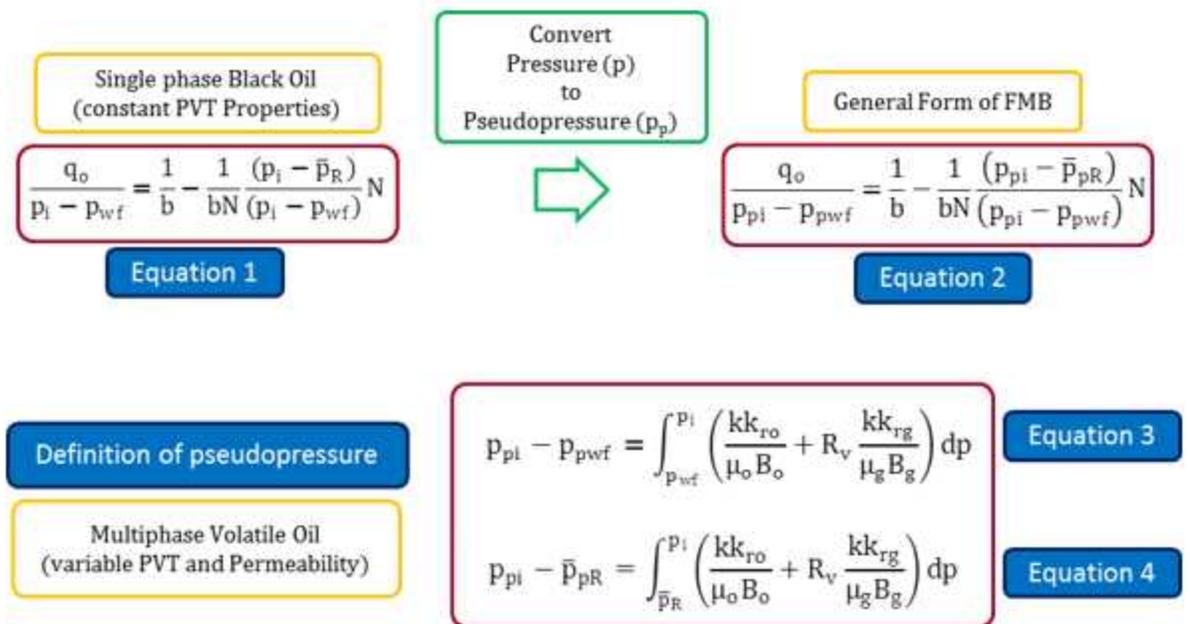
The multiphase FMB analysis is structured in a format similar to the above equation, but pressure is replaced by an appropriately defined multiphase pseudo-pressure.

$$\frac{q}{(p_{pi} - p_{pwf})} = -\frac{1}{bN} \left\{ \frac{(p_{pi} - \bar{p}_{pR})}{(p_{pi} - p_{pwf})} N \right\} + \frac{1}{b}$$

The discussion below is focused on oil as the flowing fluid of interest. The pseudo-pressure defined below is the “oil” pseudo-pressure. A parallel discussion, *mutatis mutandis* (after the necessary changes have been made), is relevant when gas is the primary fluid of interest.

The “oil” pseudo-pressure defined below accounts for:

- a. multiphase flow — oil, gas, and water, for both production and injection
- b. fluid property variations with pressure
- c. saturation changes in the reservoir caused by production or injection
- d. geomechanical effects, desorption, water influx.



In evaluating the above equations, the following considerations apply:

i: k_{rg} and k_{ro} are functions of saturation (*not* pressure). In order to evaluate the pseudo-pressure integral, the k_{rg} and k_{ro} functions have to be expressed in terms of pressure (*not* saturation). Therefore, we need to have a relationship between saturation and pressure. However, saturations depend on production. Consequently, multiphase pseudo-pressure can only be evaluated *after* the production rates are known. This is in contrast to single-phase pseudo-pressure, where the pseudo-pressure can be evaluated independently from production.

ii: At any point in time, the flow rates of gas, oil, water, and the flowing pressures are known from measurement. The average reservoir pressure is obtained from material balance equations.

iii: At any point in time, using the production data, the k_{rg} / k_{ro} ratios are determined from:

$$\frac{k_{rg}}{k_{ro}} (S_g, S_w) = \left(\frac{GOR - R_s}{1 - R_v GOR} \right) \frac{\mu_g B_g}{\mu_o B_o} \quad \text{Equation 5}$$

And the k_{rw} / k_{ro} ratios are obtained from:

$$\frac{k_{rw}}{k_{ro}}(S_g, S_w) = \text{WOR} \frac{\mu_w B_w}{\mu_o B_o}$$

Equation 6

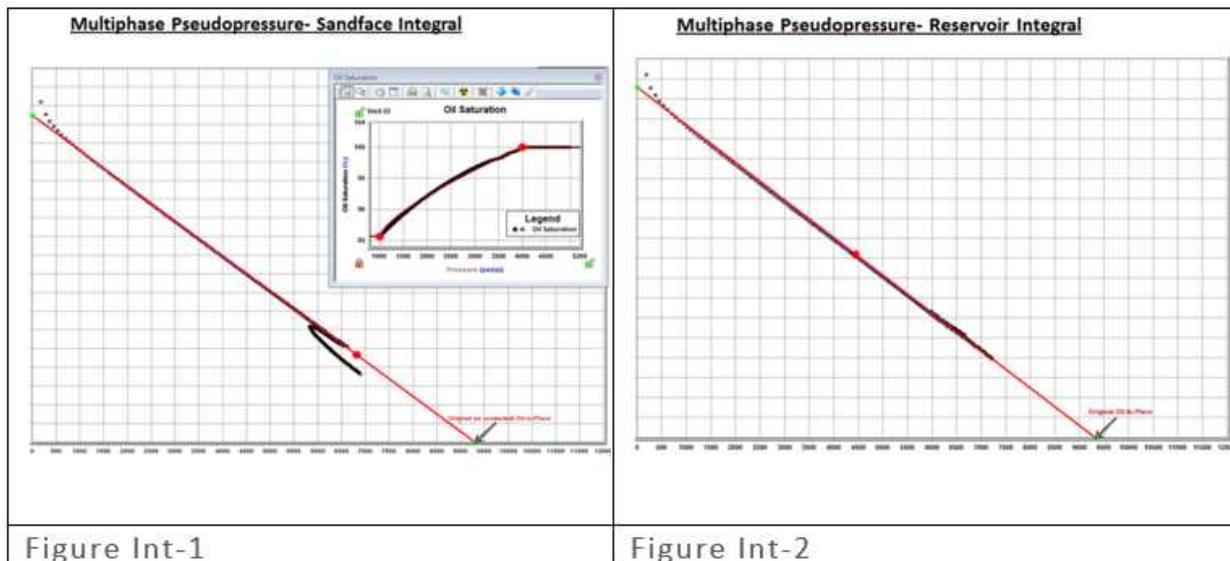
iv: The relative permeability curves are reformulated in terms of k_{rg} / k_{ro} ratios versus saturations. The k_{rg} / k_{ro} ratios will be a single curve for two-phase (gas / oil) flow, but become a surface, when water production is included.

v: From the permeability ratios obtained from production data (see step iii) and the relative permeability curves (see step iv), the saturations are obtained for every point in time, and the corresponding pseudo-pressure is evaluated, using Equations 3 and 4.

vi: The calculation of pseudo-pressure involves the evaluation of an integral. In the literature, there are two ways of doing this: a) using the Sandface Integral, or b) using the Reservoir Integral. The more rigorous of the two is the Reservoir Integral, and that is what is used in the current implementation of Harmony Enterprise. It recognizes that the saturations change, not only through time, but also with location in the reservoir. This makes the pseudo-pressure calculations complex, cumbersome, and

iterative. At every point in time, they consist of a stepwise integration from p_{wf} to \bar{p}_R , and from \bar{p}_R to p_i .

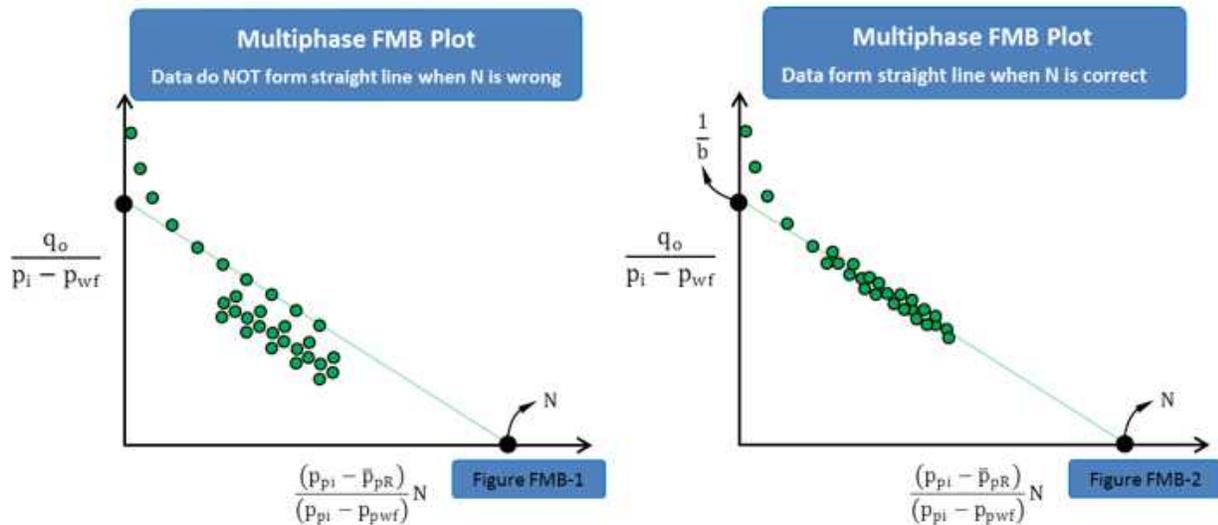
As a result, because analysis lines are dynamically calculating the pseudo-pressures, the line movement can be slow, when there is a large number of data points. Figure Int-1 and Int-2 below demonstrate that the Reservoir Integral is more effective in straightening out the multiphase data than the Sandface Integral.



vii: On the basis of Equation 2, an FMB (A-G) analysis is created by plotting $\frac{q_o}{p_i - p_{wvf}}$

versus $\frac{p_{pi} - \bar{p}_{pR}}{p_{pi} - p_{pwf}} N$.

Since the Oil-In-Place, N, is not known, the solution is iterative. The value of N is modified until the data forms a straight line. This is illustrated in Figure FMB-1 and FMB-2.



The x-intercept is the desired value of N. The y-intercept (1/b) is the (pseudo) Productivity Index, which is defined as:

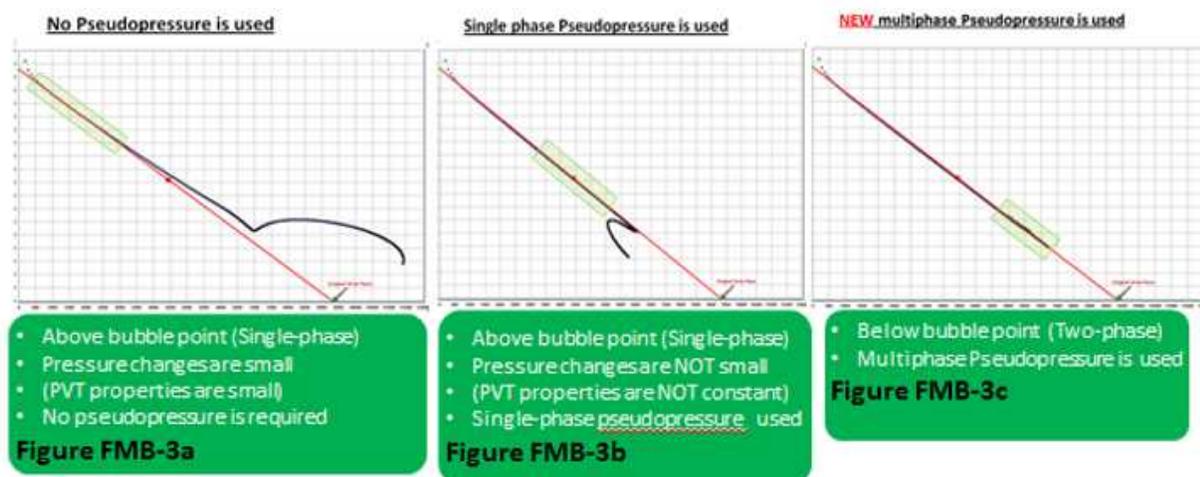
$Productivity\ Index = \frac{1}{b} = \frac{q_o}{\bar{p}_{pR} - p_{pwf}}$	Equation 7
--	------------

viii: The productivity index varies during transient flow, but becomes constant during boundary-dominated flow. Because the pseudo-productivity index is defined in terms of pseudo-pressures, variations in saturation and relative permeabilities are accounted for (albeit in an approximate manner). As a result, the pseudo-productivity index becomes a constant (dependent only on reservoir shape, size, initial permeability, initial saturations, and well completion, which are all considered to be constant).

ix: For oil wells producing below the bubble point or producing water, the results of the multiphase FMB can be significantly different from a single-phase oil analysis.

x: For oil wells producing at a flowing pressure above the bubble point, the gas produced is purely solution gas, and flow in the reservoir is actually single phase. In this situation, the traditional single phase (using “pressure” for analysis) can yield the correct value of N at the beginning (when PVT properties are still relatively constant) —

see Figure FMB-3a. When PVT properties change (while still in single-phase flow), a single-phase pseudo-pressure can be defined, and this straightens the data — see Figure FMB-3b. When pressures go below the bubble point, multiphase flow occurs and the multiphase pseudo-pressure defined above must be used to straighten the data, and obtain the correct value of N. This is demonstrated in Figure FMB-3c.



Important considerations

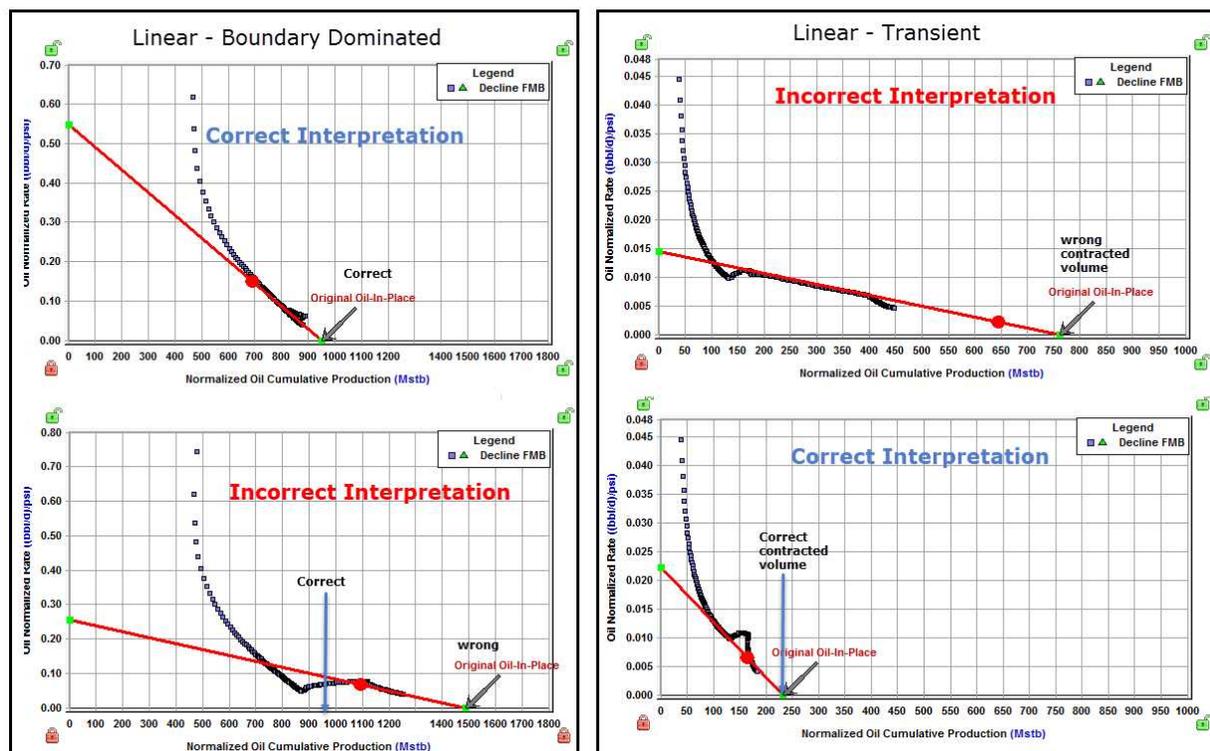
The multiphase FMB equations are developed for boundary-dominated flow, and like most reservoir engineering equations, involve simplifying assumptions. Since the multiphase FMB model has only recently been implemented, the effect of these assumptions has not been extensively evaluated, and the results must be used with caution until they have been verified in everyday production situations. Some of the issues that need to be validated through use and independent confirmation of results are discussed below:

In some of the following situations, anomalies in the behavior of the data (even synthetic data) have been observed:

- When the bubble / dew-point pressure is crossed while production is still in transient flow. However, it is expected that the data catches up to the correct trend as production continues.
- Selecting Liquid-Rich Gas in the PVT Properties section. This option is sensitive to any inconsistencies inherent in the PVT properties.
- The Z^{**} used in the flowing P/Z^{**} calculation does not account for condensate and water production. Therefore, for rich-gas condensate reservoirs and cases with significant water production, the flowing P/Z^{**} plot may not line up with the analysis line. However, the analysis is correct: the A-G straight line points to the correct Original-Gas-in-Place, and the model's verified gas flow rates

and flowing pressures are correct. The only problem is that the P/Z^{**} plot does not match, and this mismatch is not indicative of an incorrect analysis. Rather it indicates that the Z^{**} is not accounting for the liquid production.

- d. In some cases, a minimal adjustment of the relative permeability exponents (for example, changing n_g from 1.5 to 2) does improve the match between the data and the analysis.
- e. When analyzing multiphase production data in FMB, it is possible to generate an incorrect straight-line trend by increasing the volume in place. The recommended procedure is to select the **minimum** value of original-oil-in-place, which results in an A-G Analysis straight line. This issue becomes more critical when analyzing data that is still in transient flow, especially when the bubble / dew-point pressures are hit before the boundary-dominated flow is reached. An example of incorrect and correct interpretation is shown below (see item *h*).
- f. Since multiphase FMB takes into account the production rate of all phases that are entered in the Production editor, the often poorly measured or misreported water production rates might result in a more scattered FMB plot. In some jurisdictions, the condensate is inconsistently reported, sometimes as condensate production, sometimes as oil production, and sometimes as part of the (recombined) gas. These issues can be evaluated by removing these poorly reported rates from the Production editor.
- g. In analyzing the multiphase flow in the unconventional reservoir module (URM), moving the end-of-linear flow line in the square-root time plot, may cause the data to move (even when pseudo-time has not been selected). The reason for this is that by changing the end-of-linear flow line, the reservoir size is changing. Therefore, the average pressure, will correspond to a different saturation distribution, and as a result, has different pseudo-pressure calculations. For a large reservoir volume, where changes in the saturation profile are not as important as for a smaller reservoir volume (or for single-phase flow), moving the end-of-linear flow line has an insignificant effect on the data.
- h. Since FMB equations are focused on boundary-dominated flow, caution has to be exercised during transient flow. For single-phase flow, the FMB has been used to reliably estimate the “contacted” volume. However, for multiphase flow, it may not be reliable for this purpose, and may give significantly misleading results. Moreover, the effect of flow geometry has not been completely studied. Two examples that illustrate some problems with Linear and Transient Flow are shown below:



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2. Behmanesh, H., 2016, Rate–Transient Analysis of Tight Gas Condensate and Black Oil Wells Exhibiting Two–phase Flow, Ph.D. thesis, University of Calgary.
3. Behmanesh, H., Hamdi, H., Clarkson, C.R. 2017. Production data analysis of gas condensate reservoirs using two–phase viscosity and two–phase compressibility, Journal of Natural Gas Science & Engineering, doi: 10.1016/j.jngse.2017.07.035.
4. Behmanesh, H., Mattar, L., Thompson, J. M., Anderson D. M., Nakaska, D. W. and Clarkson, C. R. 2018. Treatment of Rate-Transient Analysis During Boundary-Dominated Flow. SPE Journal, SPE 189967-PA doi:10.2118/189967-PA
5. Camacho–v, R. G., and Raghavan R. 1989. Performance of wells in solution–gas–drive reservoirs. SPE Form Eval 4.(4) 611–620. SPE–16745–PA. DOI: 10.2118/16745–PA.
6. Heidari, M., Behmanesh, H., and Clarkson, C. R. 2013. Multi–Well Gas Reservoirs Production Data Analysis. Presented at the SPE Unconventional Resources Conference

Canada, Calgary, 5–7 November. SPE–167159–MS. [https://doi.org/10.2118/167159–MS](https://doi.org/10.2118/167159-MS).

7. Heidari, M., Behmanesh, H. and Clarkson, C. R. 2014. New Semi–Analytical Method for Analyzing Production Data from Constant Flowing Pressure Wells in Gas Condensate Reservoirs during Boundary–Dominated Flow. Paper SPE 169515 presented at the SPE Western North American and Rocky Mountain Joint Regional Meeting, Denver, Colorado, 16–18 April. DOI: 10.2118/169515–MS.
8. Jones, J. R., & Raghavan, R. (1988, September 1). Interpretation of Flowing Well Response in Gas-Condensate Wells (includes associated papers 19014 and 19216). Society of Petroleum Engineers. doi:10.2118/14204-PA
9. Raghavan, R. (1976, August 1). Well Test Analysis: Wells Producing by Solution Gas Drive. Society of Petroleum Engineers. doi:10.2118/5588-PA.
10. Shahamat, M. S., & Clarkson, C. R. 2017. Multi–Well, Multi–Phase Flowing Material Balance. Paper SPE 185052 prepared for Presentation at the SPE Reservoir Evaluation & Engineering – Formation Evaluation, SPE 185052-PA doi:10.2118/185052-PA.

FMB model (*patent pending*) theory

The following theory is focused on oil as the flowing fluid of interest. The pseudo-pressure referenced is the “oil” pseudo-pressure. A parallel discussion, *mutatis mutandis* (after the necessary changes have been made), is relevant when gas is the primary fluid of interest.

The Agarwal-Gardner (A-G) flowing material balance (FMB) plot yields the original-oil-in-place as the x-intercept, and the pseudo-productivity index as the y-intercept. The pseudo-productivity index is given by:

$$\text{Pseudo-Productivity Index} = \frac{q}{\bar{P}_{pR} - P_{pwf}} = \frac{1}{b}$$

The pseudo-productivity index depends on the average reservoir pseudo-pressure, the flowing pseudo-pressure, and the flowing rates of the three producing fluids: oil, gas, and water. The pseudo-productivity index is a parameter that combines Darcy’s law, material balance, and accounts for the variations of fluid and reservoir properties such as: viscosity, formation volume factor, oil-gas-water saturations, geomechanical effects, desorption, etc.

Multiphase FMB uses the rigorous material balance equation to determine the average reservoir pressure, as a function of oil, gas, and water production for specified values of original-oil-gas-water-in-place. Multiphase FMB can account for the presence of water influx, and includes both production and injection rates. In addition, multiphase FMB also takes into account variations of fluid and reservoir properties such as: formation volume factor, oil-gas-water saturation, geo-mechanical effects, and desorption.

Having determined the oil pseudo-productivity index and the average pseudo-pressure in the FMB analysis, the FMB model uses the pseudo-productivity index and material balance equations in reverse, as follows:

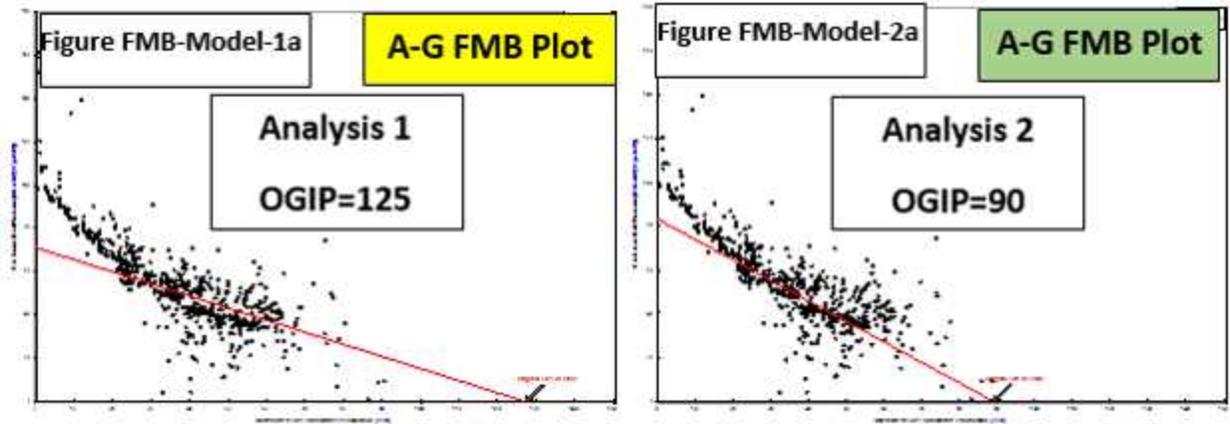
1. Using the pseudo-productivity index:
 - a. **Oil Rate** — uses the measured flowing pressure to calculate a synthetic oil rate, and compares the synthetic and measured oil rates. Modifies the productivity index and the original-oil-in-place, N , until an acceptable history-match of the oil rates is obtained.
 - b. **Flowing Pressure** — uses the measured oil rate to calculate a flowing pressure, and compares the synthetic and measured flowing pressures. Modifies the productivity index and the original-oil-in-place, N , until an acceptable history-match of the flowing pressures is obtained.
 - c. **Average Pressure** — uses the measured flowing pressure and the flowing oil rate to calculate a synthetic average reservoir pressure. Modifies the productivity index and the original-oil-in-place, N , until an acceptable history-match of the average pressure with 2a (see below) is obtained.
2. Using the material balance equation:
 - a. **Average Pressure** — uses the measured flowing pressure and the flowing oil rate to calculate a synthetic average reservoir pressure. Modifies the productivity index and the original-oil-in-place, N , until an acceptable history-match of the average pressure with 1c (see above) is obtained.

Novelty of the FMB model

Historically, the FMB analysis is based on the A-G analysis (Agarwal et al. 1999). An example of an A-G FMB plot is shown in Figure FMB-Model-1a and FMB-Model-2a. This example is a multiphase gas well, but the FMB model applies to multiphase oil wells as well.

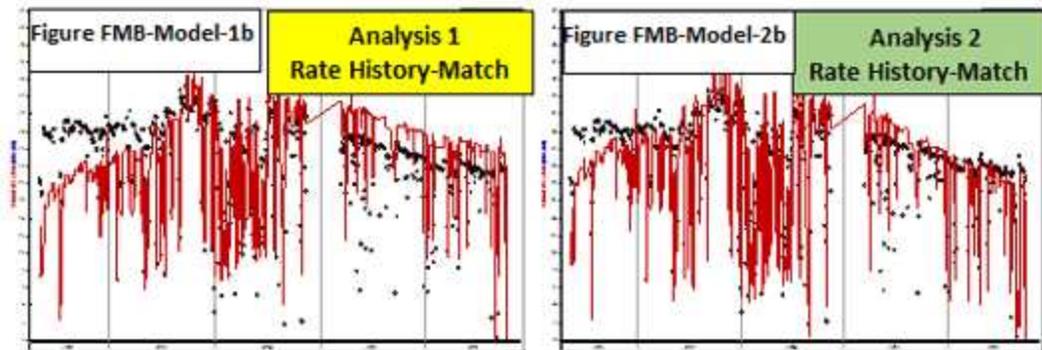
Figure FMB-Model-1a and FMB-Model-2a are plots of different analyses of the same data. Both analyses appear reasonable, but they give significantly different answers. It is obvious that for this dataset, the analysis' straight line can be placed in many locations, and that the cor-

responding original-gas-in-place values are non-unique over a wide range. Up until recently, there was no way out of this dilemma.

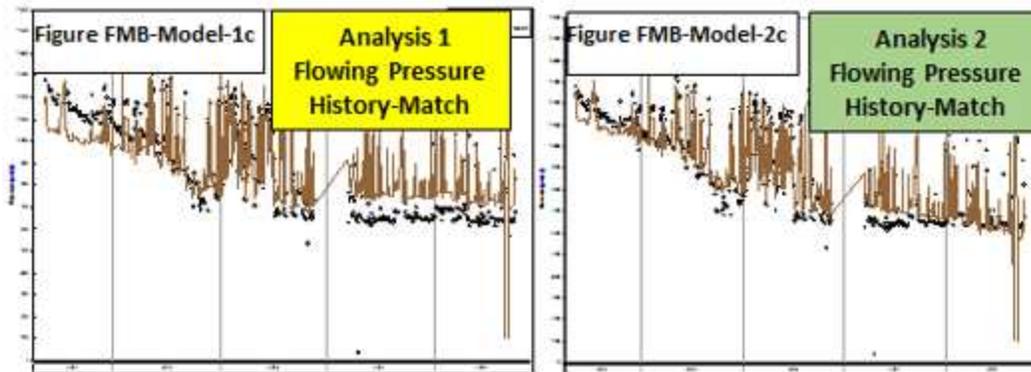


The FMB model solves this problem by creating a history-match of the flowing pressures, or the flow rates.

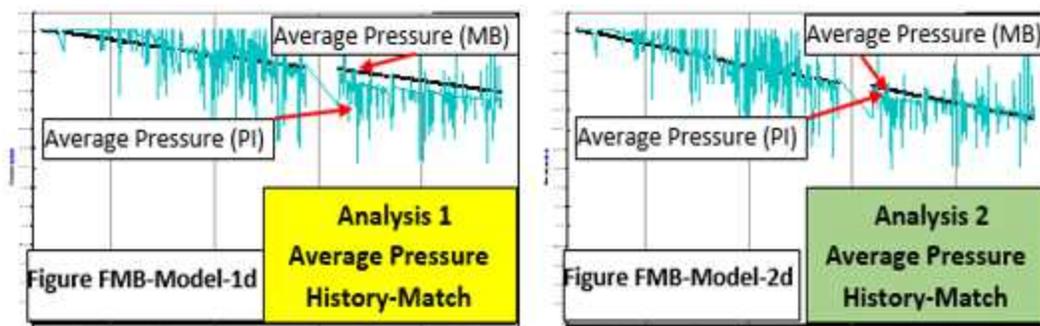
Figure FMB-Model-1b shows the rate history-match corresponding to Analysis 1. Clearly, this history-match is unacceptable. On the other hand, Figure FMB-Model-2b shows the rate history-match corresponding to Analysis 2. Clearly, this is an excellent history-match and confirms that the original-oil-in-place determined from Analysis 2 is *consistent* with the data, whereas that of Analysis 1 is *inconsistent*.



Similarly, Figure 1c and 2c are history-matches of the flowing pressures and confirm that Analysis 1 is *incorrect*, and that Analysis 2 is *correct*.



In addition to the rate history-match and the flowing pressures history-match, the FMB model can generate the average pressure within the drainage area of a well. This is shown in Figure FMB-Model-1d and FMB-Model-2d. The average reservoir pressure can be generated in two ways: from the productivity index (PI) and from the material balance (MB). When these two methods are congruent, the analysis is correct, as shown in Figure FMB-Model 2d. The utility of this plot is discussed further in reservoir group identification.



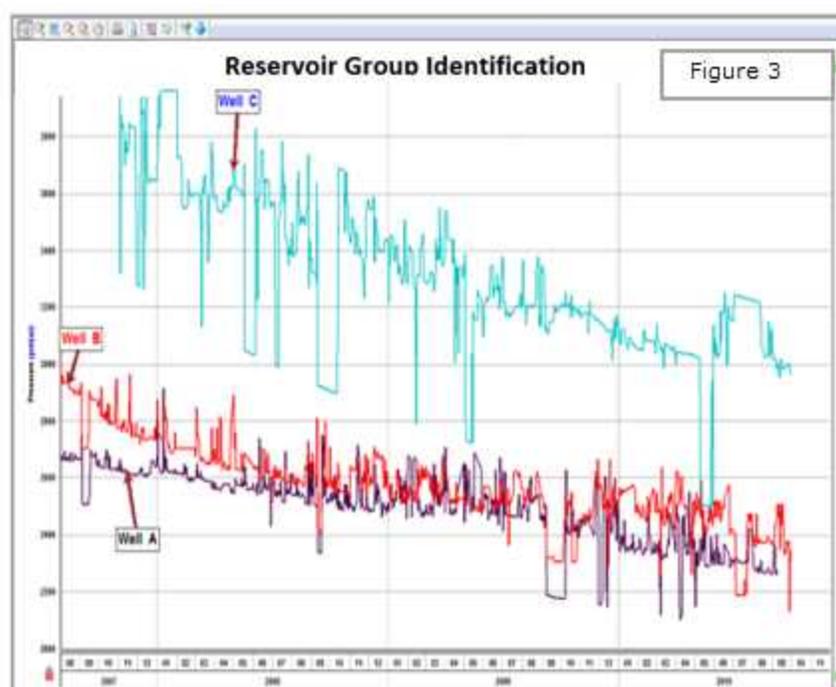
The conclusion for this example, is that the original-oil-in-place for this well is 90 BCF. This conclusion would not have been possible without the FMB model.

Reservoir group identification

The objective for using the Reservoir Group Identification plot is to identify which wells are in the same reservoir, and which wells are in separate reservoirs. If there are several wells producing from the same reservoir under stable conditions, they establish their own drainage areas, approximately in proportion to their flow rates. These drainage areas vary in shape and size, and depend in part on the flow rates. If the well's flow rates change, the no-flow boundaries between the wells move, and each well's drainage area changes correspondingly, until all the drainage areas have the same average pressure within them.

The phenomenon that, under stable flowing conditions, wells in the same reservoir have a common average pressure within their drainage areas as a function of time, provides a diagnostic to identify if two wells are in the same reservoir, or in different reservoirs.

Using the FMB model, the average pressure within the drainage area can be determined by selecting **Average Pressure** — see Figure FMB-Model-2d above. For each well, determine the correct average pressures (FMB Model Pressure-PI) as shown in Figure 2d. Compare these average pressures in the Comparison plot, as a function of time. If they follow the same trend, they most-likely belong to the same reservoir — (see Wells A and B in Figure 3), and if they have different trends, they most-likely belong to separate reservoirs — (see Well C in Figure 3).



Duong decline analysis theory

The Duong analysis was developed specifically for unconventional reservoirs with very low permeability. The shape of the curve is suited for wells that exhibit long periods of transient flow. The Duong method will reach a finite EUR, and tends to be more conservative than traditional Arps declines with $b > 1$.

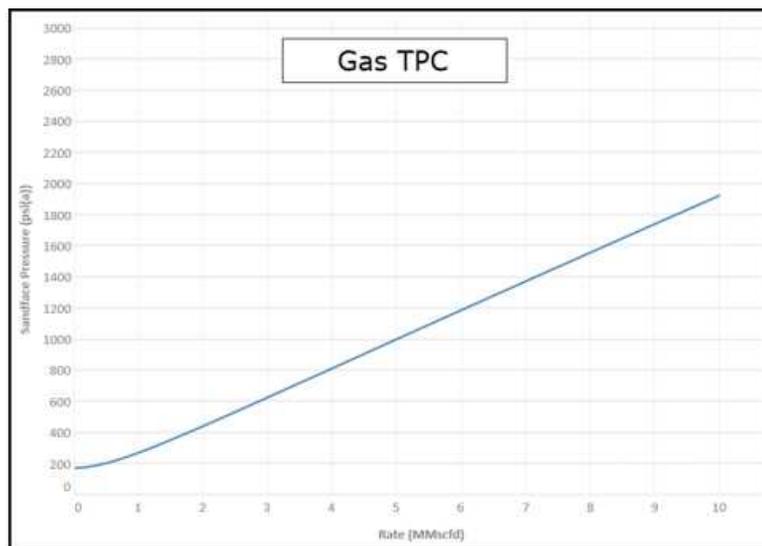
The Duong Production Decline Model		
$q =$	$q_1 t^{-m} \exp\left[\frac{a}{1-m}(t^{1-m} - 1)\right] + q_\infty$	Rate expression as a function of time
$Q =$	$\frac{q_1}{a} \exp\left[\frac{a}{1-m}(t^{1-m} - 1)\right]$	Cumulative production as a function of time

EUR =	$\frac{q_f}{a} t_f^m$	EUR in terms of model parameters
Reference SPE paper 137748.		

Gas IPR / TPC theory

TPC

A tubing performance curve (TPC) is a graphical representation of the pressure response of a wellbore completion to a range of fluid rates. With a Harmony Optimize license, you can plot a TPC as a relationship between sandface flowing pressure vs. gas rate.



The inputs needed to create a gas TPC curve are as follows:

- Wellhead pressure
- Ratios (OGR and WGR)
- A valid wellbore configuration
See the [Wellbore editor](#) for details.
- Valid fluid properties
See the [Properties editor](#) for details.

Using these inputs, a series of [pressure loss calculations](#) are done over a range of gas rates, and then a line is drawn through all the points to create a curve. The default setting is to plot 64

points, using equally spaced gas rates up to a maximum rate defined by the largest inflow performance relationship (IPR).

Simplified C, n deliverability

Simplified C,n deliverability (also known as the Rawlins-Schellhardt equation) uses the back-pressure equation to define the well's deliverability. The back-pressure equation is an empirically derived industry standard that applies to gas wells, independent of reservoir drive. It is generally derived from a well test (for example, isochronal test). The back-pressure equation is stated as:

$$q = C(p_R^2 - p_{wf}^2)^n$$

where:

q = flow rate, MMscfd or 10³m³/d

C = constant, MMscfd / (psi²)ⁿ or (10³m³/d/kPa²)ⁿ

n = turbulence of flow, dimensionless

p_R = reservoir pressure, psia or kPaa

p_{wf} = sandface flowing pressure, psia or kPaa

“C” value

The “C” value defines the magnitude of the well's rate response to changes in pressure.

“n” value

The "n" value describes the effect of turbulence in the near-wellbore region. Wells that are operating at high drawdowns, or wells with high permeability, can experience significant energy loss in the near-wellbore region due to the development of turbulent flow from the high gas velocities. The “n” value helps account for this effect.

An "n" value equal to 1 describes completely laminar flow (no turbulence), and an "n" equal to 0.5 describes a very turbulent flow. In practice, values equal to 1 or 0.5 are not seen, but it is fairly common industry practice to use an n of 1 on low-to-mid deliverability gas wells that are not expected to operate at low drawdowns, and thus, where turbulent effects are minimal.

Values of n closer to 0.5 are most appropriate for wells that are expected to flow at high drawdowns, or for wells with high deliverability potential. Values approaching 1 are most appropriate for aging wells, or for low deliverability wells.

Note: The n value cannot be less than 0.5, or greater than 1.0. Input values less than 0.5 are automatically set to 0.5, and values greater than 1.0 are automatically set to 1.0.

Forchheimer deliverability

Forchheimer deliverability (also known as the Laminar-Inertial-Turbulent or LIT equation) is another method to define a gas well's deliverability. The Forchheimer equation is stated as:

$$p_R^2 - p_{wf}^2 = aq + bq^2$$

or

$$p_{pR} - p_{pwf} = aq + bq^2$$

where:

aq = pressure drop due to laminar flow and wellbore effects

bq = pressure drop due to inertial-turbulent flow effects

p_R = reservoir pressure

p_{wf} = sandface flowing pressure

In general, values for “a” and “b” are determined from a well test (for example, isochronal test). If no well test is available, then the equations can be re-written in terms of reservoir parameters.

“a” and “b” values rewritten in terms of reservoir parameters

Pressure-squared method (in US Oilfield units):

$$a = \frac{(3.263 \times 10^6) \mu Z T}{k h} \left[\log \left(\frac{0.472 r_e}{r_w} \right) + \frac{s}{2.303} \right]$$

$$b = \frac{(1.417 \times 10^6) \mu Z T}{k h} D$$

Pseudo-pressure method (in US Oilfield units):

$$a = \frac{(3.263 \times 10^6) T}{k h} \left[\log \left(\frac{0.472 r_e}{r_w} \right) + \frac{s}{2.303} \right]$$

$$b = \frac{(1.417 \times 10^6) T}{k h} D$$

Liquid Loading Monitor theory

The overall logic for the Liquid Loading Monitor ([Liquid Loading sub-tab](#)) is as follows:

- Obtain the gas properties for the well (or scenario) from the [Properties editor](#).
- Use a Harmony Reservoir™ model's forecast. (Forecasts from analytical or numerical models are used since they have both rate and sandface pressure.)
- For each timestep in the forecast:
 - Obtain the sandface pressure, sandface temperature, and wellbore flow path diameter.
 - Use the sandface pressure and temperature, along with gas properties, to determine the gas compressibility factor (Z) and gas density.
 - Calculate the liquid loading rate from that gas density and the wellbore flow path diameter.
 - Compare the liquid loading rate to the actual gas rate from the model's forecast
- Indicate the timestep where the actual gas rate is less than the liquid loading gas rate

Note: As with other Harmony Optimize™ tools, liquid loading calculation details can be configured in the [Wellbore editor](#). This includes the liquid loading equation (Turner, Coleman, or custom), the liquid used to calculate against (water or condensate), and the location of the wellbore flow path diameter (either at [EOT](#) or datum). The default equation is Turner with water, and the default location for the flow path diameter is at EOT.

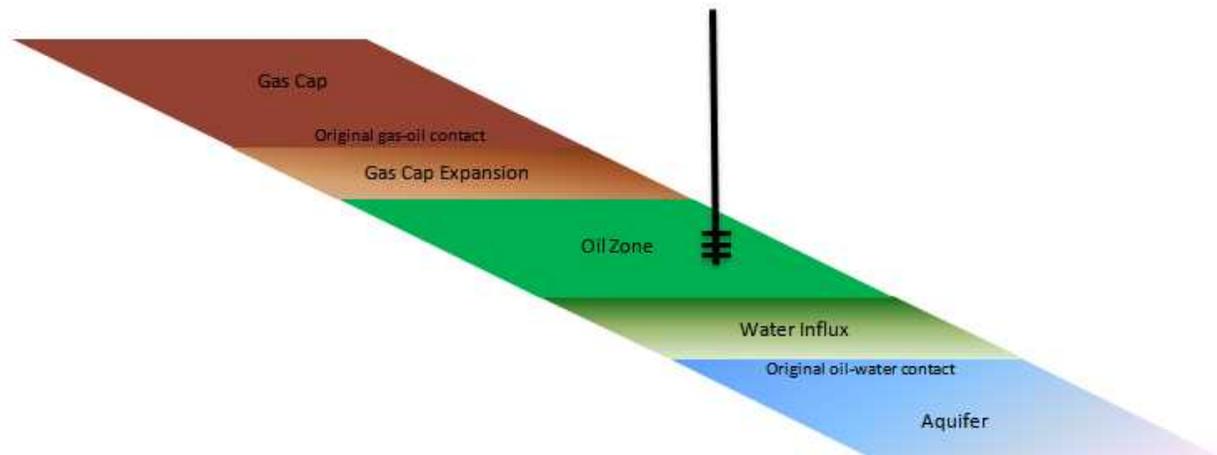
As can be seen from the logic steps above, the math used to calculate the liquid loading threshold in the [Liquid Loading Monitor](#) is less precise than other Optimize tools. For example, the [Flowing Gradient](#) tool shows liquid loading velocity vs. actual velocity all along the wellbore – even if the wellbore diameter changes with depth. On the other hand, the Liquid Loading Monitor exclusively uses the sandface pressure and temperature to calculate gas properties, and compares that against a single diameter. Furthermore, model forecasts usually default to monthly timesteps. For example, if the Monitor displays that liquid loading occurs on “March 8th, 2024”, it is likely that the previous timestep was February 8th (and therefore the liquid loading threshold could have been passed on February 9th). Consider this tool to be a simple diagnostic, while other Optimize tools use more detailed information.

Material balance analysis theory

Overview

Material balance analysis is an interpretation method used to determine original fluids-in-place (OFIP) based on production and static pressure data. The general material balance equation relates the original oil, gas, and water in the reservoir to production volumes and current pressure conditions / fluid properties. The material balance equations considered assume tank-type behavior at any given datum depth — the reservoir is considered to have the same pressure and fluid properties at any location in the reservoir. This assumption is quite reasonable provided that quality production and static pressure measurements are obtained.

Consider the case of the depletion of the reservoir shown below. At a given time after the production of fluids from the reservoir has commenced, the pressure drops from its initial reservoir pressure p_i , to some average reservoir pressure, p . Using the law of mass balance, during the pressure drop (Δp), the expansion of the fluids left over in the reservoir must be equal to the volume of fluids produced from the reservoir.



The simplest way to visualize material balance is that if the measured surface volume of oil, gas, and water were returned to a reservoir at the reduced pressure, it must fit exactly into the volume of the total fluid expansion, plus the fluid influx.

The general form of the equation can be described as net withdrawal (withdrawal - injection) = expansion of the hydrocarbon fluids in the system + cumulative water influx. This is shown in the equation below.

$$\begin{aligned}
 & N_p [B_o + B_g (R_p - R_s)] + W_p B_w - W_{inj} B_{winj} - G_{inj} B_{ginj} \\
 & = N \left\{ [B_o - B_{oi} + B_g (R_{si} - R_s)] + \frac{B_{oi}}{B_{gi}} m (B_g - B_{gi}) \right. \\
 & \quad \left. + B_{oi} (1 + m) \left(\frac{c_f + c_w S_w}{1 - S_w} \Delta p \right) \right\} + W_e B_w
 \end{aligned}$$

Each term in the equation can be grouped based on the part of the system it represents. The table below shows the terms and a simplified version of the general equation based on the terms.

Summary of terms in the material balance equation

Term	Description
$F = NE_t + W_e B_w$	Simplified general equation.
$F = N_p [B_o + B_g (R_p - R_s)] + W_p B_w - W_{inj} B_{winj} - G_{inj} B_{ginj}$	Volume of withdrawal (production and injection) at reservoir conditions is determined by the oil, water, and gas produced at the surface.
$E_t = E_o + \frac{B_{oi}}{B_{gi}} m E_g + B_{oi} (1 + m) E_{fw}$	Total expansion.
$E_o = B_o - B_{oi} + B_g (R_{si} - R_s)$	If the oil column is initially at the bubble point, reducing the pressure results in the

Term	Description
	release of gas and the shrinkage of oil. The remaining oil consists of oil, and the remaining gas still dissolved at the reduced pressure.
$E_g = B_g - B_{gi}$	Gas expansion factor. For example, as the reservoir depletes, the gas cap expands into the reservoir volume previously occupied by oil.
$E_{fw} = \frac{c_f + c_w S_w}{1 - S_w} \Delta p$	Even though water has low compressibility, the volume of connate water in the system is usually large enough to be significant. The water expands to fill the emptying pore spaces as the reservoir

Term	Description
	<p>depletes. As the reservoir is produced, the pressure declines and the entire reservoir pore volume is reduced due to compaction. The change in volume expels an equal volume of fluid as production, and is therefore additive in the expansion terms.</p>
$m = \frac{GB_{gi}}{NB_{oi}}$	<p>Ratio of gas cap to original oil in place. A gas cap also implies that the initial pressure in the oil column must be equal to the bubble point pressure.</p>
$W_e B_w$	<p>If the reservoir is connected to an active aquifer, then once the pressure drop is communicated</p>

Term	Description
	throughout the reservoir, the water encroaches into the reservoir resulting in a net water influx.

Not all terms are used at any one time, but the purpose of a complete equation is to provide a basis from which to analyze many types of reservoirs: gas expansion, solution gas drive, gas cap drive, water drive, etc. Terms that are not needed for a particular reservoir type cancel out of the equation. For example, when there is no gas cap originally present, the G and B_{gi} terms are zero.

Application of material balance

Material balance is an important concept in reservoir engineering because it is a performance-based tool used to establish the original volume of hydrocarbons-in-place in a reservoir that typically contains many wells. Additionally, the process of matching pressure-based depletion trends between wells gives the reservoir engineer the ability to create a performance-based view of the connected pore volume in the reservoir. Consequently, it is important that:

1. All fluids taken from, or injected into the reservoir be measured accurately.
2. Pressure, volume, and temperature characteristics (PVT properties) be measured and validated. Subsurface samples from several properly conditioned wells are preferred.
3. At least one static pressure from each well prior to production, and several after production has commenced, are required to achieve good results.

The establishment of original-in-place fluid volumes and connected pore volume are critical to the development of ongoing depletion plans, especially where secondary or tertiary recovery methods are being considered.

Gas material balance

Gas material balance is a simplified version of the general material balance equation. When the general equation is reduced to its simplest form containing only gas terms, it appears as shown below:

$$G = \frac{G_p B_g}{(B_g - B_{gi})}$$

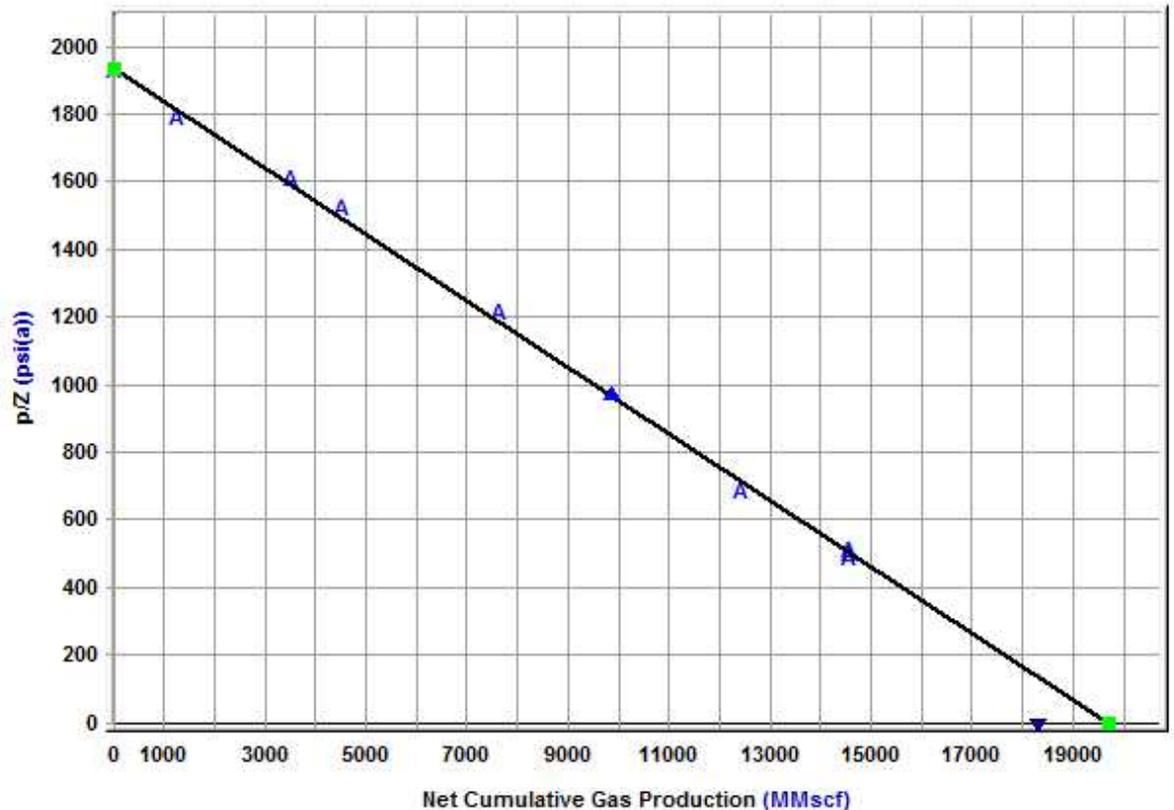
In this equation, it is assumed that gas expansion is the only driving force causing production. This form is commonly used because the expansion of gas often dominates over the expansion of oil, water, and rock. B_g is the ratio of gas volume at reservoir conditions to gas volume at standard conditions. This is expanded using the real gas law.

$$B_g = \frac{V_{res}}{V_{std}} = \frac{Z_{res} n R T_{res} p_{std}}{Z_{std} n R T_{std} p_{res}}$$

The reservoir temperature is considered to remain constant. The compressibility factor (Z) for standard conditions is assumed to be 1. The number of moles of gas do not change from reservoir to surface. Standard temperature and pressure are known constants. When B_g is replaced and the constants are canceled out, the gas material balance equation then simplifies to:

$$\frac{p}{Z} = - \left(\frac{p_i}{Z_i} \frac{1}{G} \right) G_p + \frac{p_i}{Z_i}$$

When plotted on a graph of p/Z versus cumulative production, the equation can be analyzed as a linear relationship. Several measurements of static pressure and the corresponding cumulative productions can be used to determine the x-intercept of the plot - the original gas-in-place (OGIP), shown as G in the equation.



Advanced gas material balance

For a volumetric gas reservoir, gas expansion (the most significant source of energy) dominates depletion behavior; and the general gas material balance equation is a very simple, yet powerful tool for interpretation. However, in cases where other sources of energy are significant enough to cause deviation from the linear behavior of a p/Z plot, a more sophisticated tool is required. For this, a more advanced form of the material balance equation has been developed, and the standard p/Z plot is modified to maintain a linear trend with the simplicity of interpretation.

In his work on CBM, King (1993) introduced p/Z* to replace p/Z. By modifying Z, parameters to incorporate the effects of adsorbed gas were incorporated, so the total gas-in-place is interpreted, rather than just the free gas-in-place; and a straight line analysis technique is still used. This concept has been extended to additional reservoir types with Fekete's p/Z** method (Moghadam et al. 2009).

The reservoir types considered in the advanced material balance equation are: overpressured reservoirs, water-drive reservoirs, and connected reservoirs. The total Z** equation is shown below with the modified material balance equation.

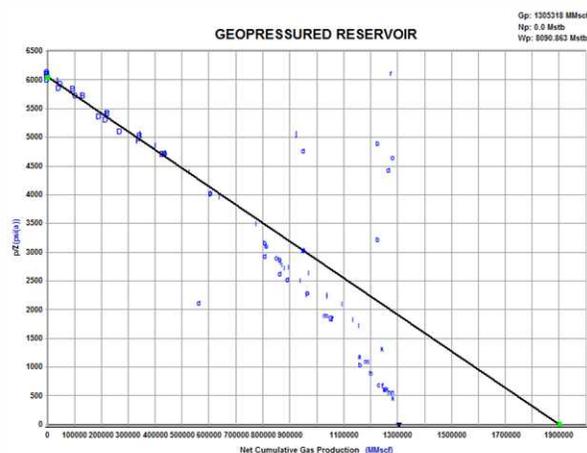
$$\frac{p}{Z^{**}} = \frac{p_i}{Z_i^{**}} \left(1 - \frac{G_p}{G} \right)$$

$$Z^{**} = \frac{p}{\left[\frac{1}{S_{gi}} \frac{p}{Z} (S_{gi} - c_{wip} - c_{ep} - c_d) + \frac{p_i}{Z_i} \left(\frac{G}{G_f} - 1 \right) \right] \frac{G_f}{G}}$$

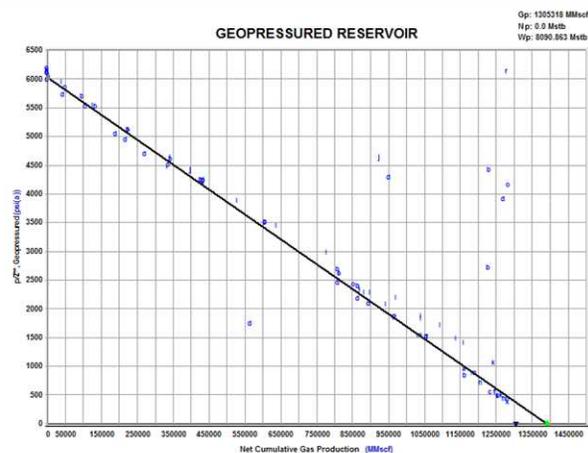
Note: The p/Z* and p/Z** methods were developed for dry gas reservoirs. They may not work with liquid-rich gas reservoirs.

Overpressured reservoir

At typical reservoir conditions, gas compressibility is orders of magnitude greater than that of the formation rock or residual fluids. In reservoirs at high initial pressures the gas compressibility is much lower, in the same order of magnitude as the formation. A typical example of this is an overpressured reservoir, which is a reservoir at a higher pressure than the hydrostatic column of water at that depth — in other words, a higher than expected initial pressure given the depth. In this situation, ignoring the formation and residual fluid compressibility results in over-prediction of the original gas-in-place. The initial depletion shows the effects of both depletion and reservoir compaction, and the slope of a p/Z plot is shallower. Once the pressure is much lower than the initial pressure, gas expansion is dominant and a steeper slope is observed on the p/Z plot. When matching on the shallower slope of this bow-shaped trend, all later pressure data is lower than the analysis line, and the estimated original gas-in-place is higher than the true original gas-in-place. The plot below shows an overpressured reservoir matched on the initial data, and the analysis line of the advance material balance method.



p/Z plot



p/Z plot**

Based on the definition of compressibility, the following equation represents the total effect of formation and residual fluid compressibility:

$$\Delta V_{ep} = \frac{B_{gi}G}{S_{gi}} \left[\left(1 - e^{-\int_p^{p_i} c_f dp} \right) + S_{wi} \left(e^{\int_p^{p_i} c_w dp} - 1 \right) + S_{oi} \left(e^{\int_p^{p_i} c_o dp} - 1 \right) \right]$$

The approximate form of this equation, found by considering compressibility for oil, water, and the formation as constant; and e^x as $1 + x$, is:

$$\Delta V_{ep} = \frac{B_{gi}G}{S_{gi}} (c_f + S_{wi}c_w + S_{oi}c_o)(p_i - p)$$

In order to use this compressibility in the material balance equation, the change in pore volume is taken relative to the initial pore volume. The rigorous and approximate forms are shown below.

Rigorous form:

$$c_{ep} = \left(1 - e^{-\int_p^{p_i} c_f dp} \right) + S_{wi} \left(e^{\int_p^{p_i} c_w dp} - 1 \right) + S_{oi} \left(e^{\int_p^{p_i} c_o dp} - 1 \right)$$

Approximate form:

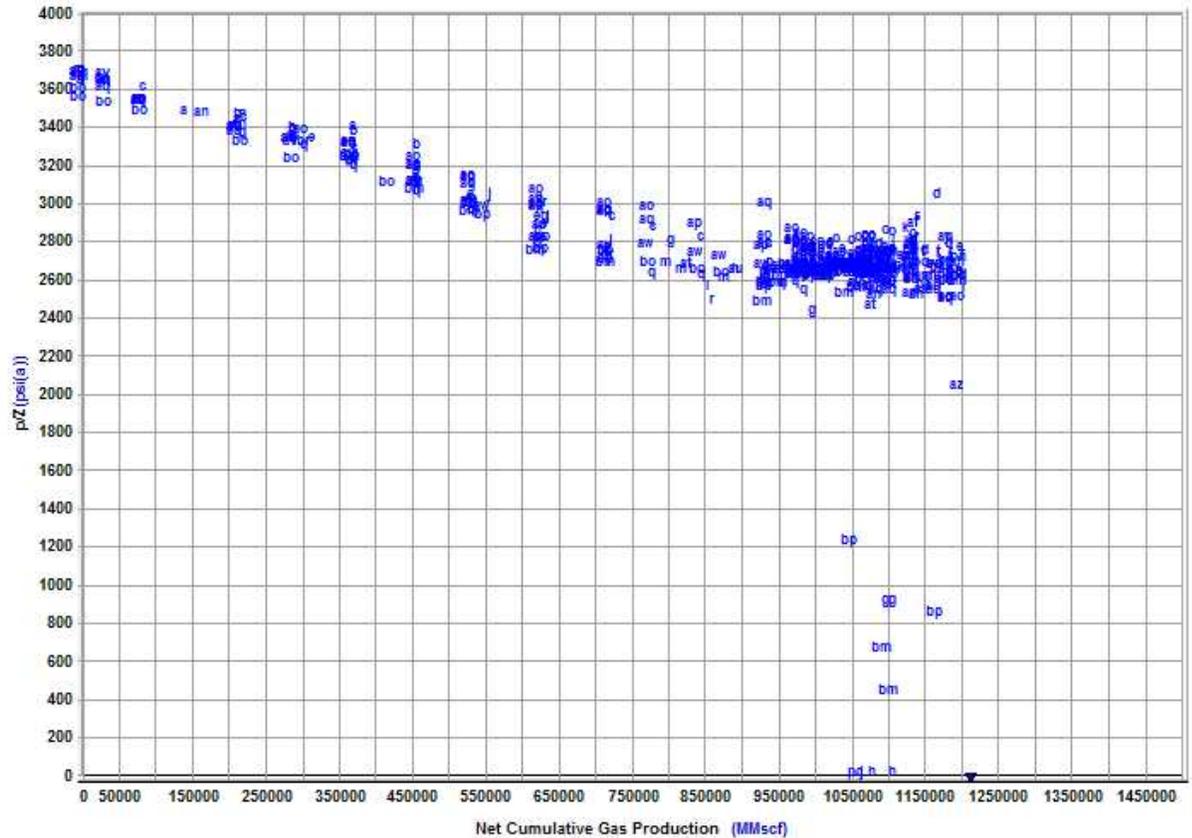
$$c_{ep} = (c_f + S_{wi}c_w + S_{oi}c_o)(p_i - p)$$

Water-drive reservoir

Some gas reservoirs may be connected to aquifers that provide pressure support to the gas reservoir as it is depleted. In this case, the pressure decrease in the gas reservoir is balanced by water encroaching into the reservoir. As this happens, the pore volume of gas is decreasing and the average reservoir pressure is maintained. Often this reservoir shows a flat pressure trend after some depletion. An example of this behavior on a p/Z plot is shown below.

Gp: 1212424 MMscf
Np: 0.0 Mstb
Wp: 118262.939 Mstb

Water-drive Reservoir



The change in reservoir volume due to net encroached water can be determined from the following equation:

$$\Delta V_{wip} = 5.615(W_e - W_\rho B_w)$$

To use this in the material balance, the change in pore volume is taken relative to the initial pore volume, shown below.

$$C_{wip} = \frac{5.615 (W_e - W_\rho B_w)}{B_{gi} G / S_{gi}}$$

When dealing with this equation, the major unknown value to be determined is water encroachment from the aquifer (W_e). Two aquifer models are provided to determine net encroached water: Schilthuis Steady-State Model and Fetkovich Model.

Schilthuis steady-state model

This is the simplest aquifer model and assumes the rate of water influx is proportional to pressure drawdown. In this model it is assumed that the aquifer volume is much larger than the gas reservoir and remains at the initial pressure.

$$W_e = K \int_0^t (p_i - p) dt = K \sum_{j=0}^n \left(p_i - \frac{p_j + p_{j-1}}{2} \right) (t_j - t_{j-1})$$

Using this model, the only parameter to solve for is the transfer coefficient (J).

Fetkovich

In the Fetkovich aquifer, the aquifer is assumed to be in pseudo-steady state and depleted according to the material balance equation. In this model, both the aquifer volume and transfer coefficient must be determined. The equations are shown below.

$$W_e = K \int_0^t (p_i - p) dt = K \sum_{j=0}^n \left(p_i - \frac{p_j + p_{j-1}}{2} \right) (t_j - t_{j-1})$$

$$W_{ei} = c_w p_{aqi} V_{aq}$$

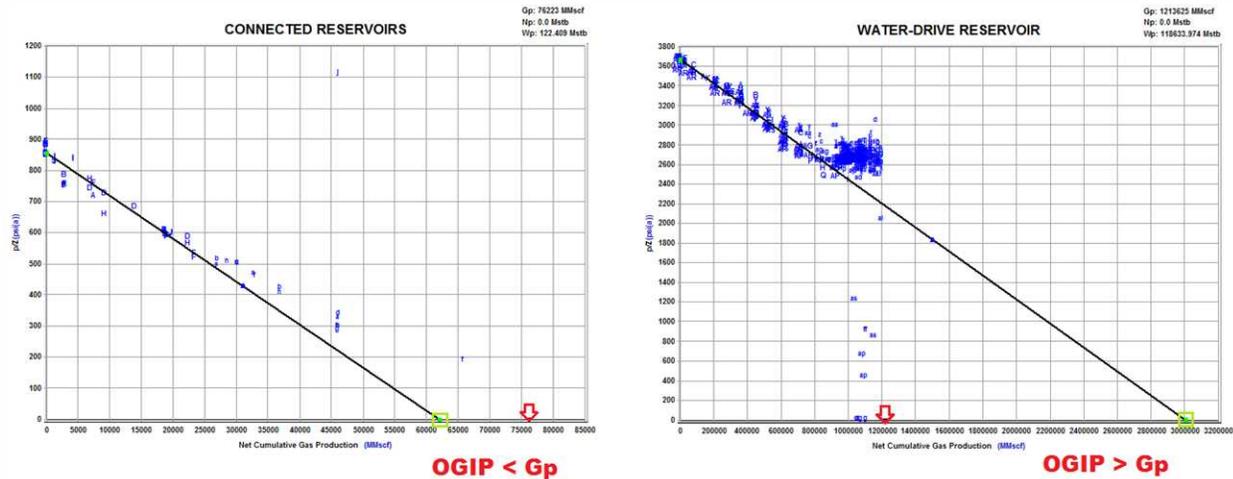
$$J = \frac{k h}{141.2 \mu \left(\ln \frac{r_e}{r_o} - \frac{3}{4} \right)} \frac{\theta}{360}$$

While the transfer coefficient is defined, the required inputs to calculate the transfer coefficient are often not known. More commonly the transfer coefficient is determined as part of matching the p/Z plot.

Connected reservoir

Another scenario which appears as pressure support on the p/Z plot is the connected reservoir model. The generic description is that two gas reservoirs are connected, described by a transfer coefficient between them, and gas feeds from one tank to the other as one of the tanks is depleted. This can be observed with two gas reservoirs with some communication, two zones in a reservoir with different permeability, or some barrier between them, or even another way of considering the situation of free and adsorbed gas in a reservoir. Because both water-drive and connected reservoirs show pressure support, it can be easy to mistake which model should be used. In a connected reservoir, the influx into the main reservoir is gas, as compared to an influx of

water in water-drive. So the pressure support is accompanied by more gas in the reservoir, rather than a shrinking reservoir as in water-drive. Typically if the initial p/Z trend points to an original gas-in-place smaller than the cumulative production, a connected reservoir is the appropriate model to use.



For a connected reservoir, the material balance equation is written as shown below to account for gas influx.

$$\frac{p_1}{Z_1} (S_{gi} - c_{wip} - c_{ep}) = \frac{p_i}{Z_i} \left(1 - \frac{G_{p1} + G_T}{G_1} \right) S_{gi}$$

$$\frac{p_2}{Z_2} (S_{gi} - c_{wip} - c_{ep}) = \frac{p_i}{Z_i} \left(1 - \frac{G_{p2} + G_T}{G_2} \right) S_{gi}$$

This can be converted into a dimensionless term similar to the terms describing relative change in pore volume (c_{wip} , c_{ep} , and c_d) for other models, as shown below.

$$c_d = - \frac{Z_1}{p_1} \frac{p_i}{Z_i} S_{gi} \frac{G_T}{G_1}$$

Similar to the water-drive model, the influx of gas from the second reservoir (G_T) is likely not a known value, and therefore it must be determined based on the size of the connected reservoir, and the transfer coefficient between the reservoirs. The equation for gas influx is shown below.

$$\Delta G_T = C(p_1 - p_2)\Delta t$$

Oil material balance

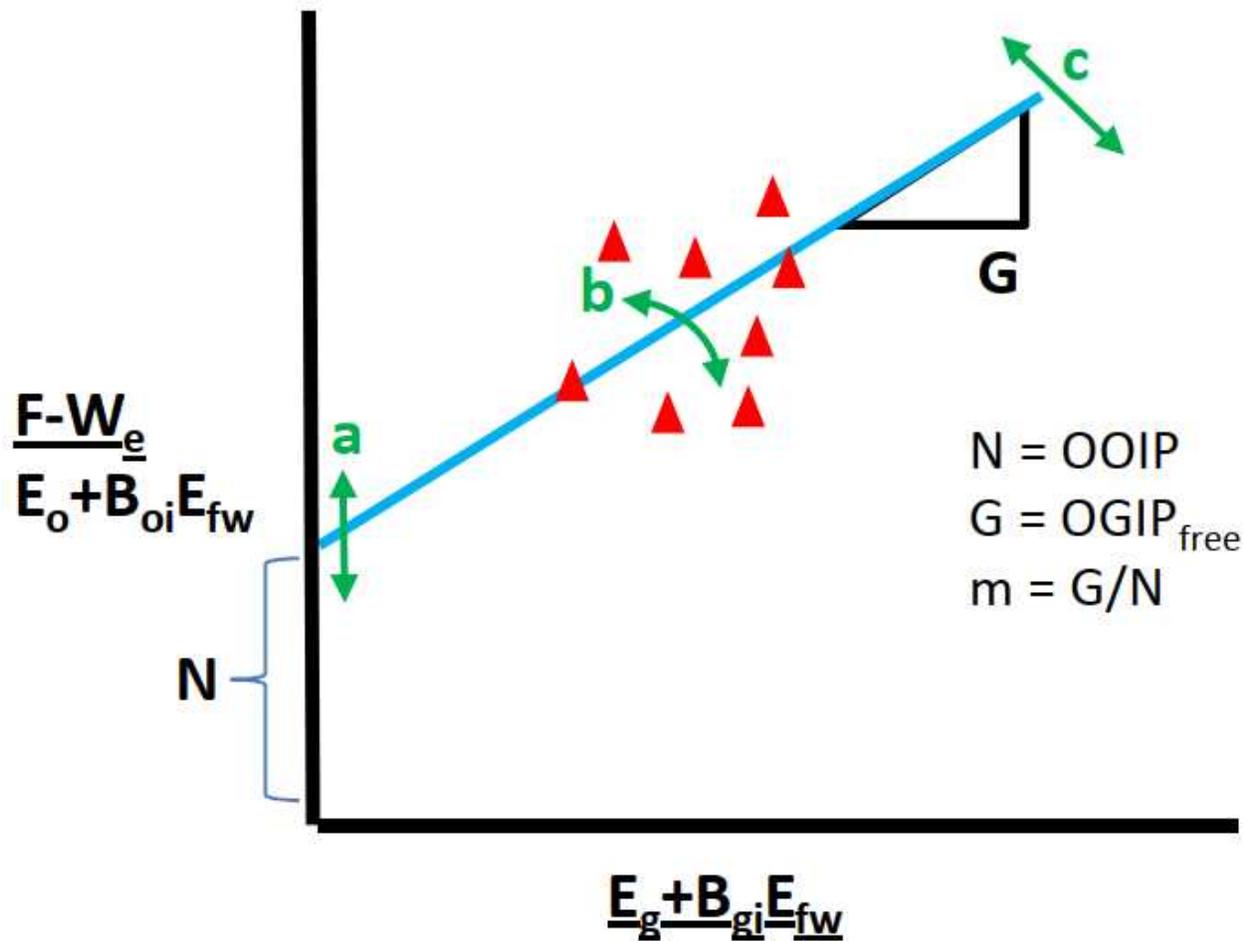
As seen in the general material balance equation, there are many unknowns, and as a result, finding an exact or unique solution can be difficult. However, using other techniques to help determine some variables (for example, m or original gas-in-place from volumetrics or seismic), the equation can be simplified to yield a more useful answer. Various plots are available to conduct an oil material balance rather than calculating an answer from individual measurements of reservoir pressure.

Havlena-Odeh (all reservoir types)

Similar to the interpretation of gas material balance, oil material balance uses plotting techniques. However, unlike the equation for single-phase gas expansion, the standard form of the material balance equation for oil reservoirs does not easily yield a linear relationship. The equation can be organized to show linear behavior. Based on the rearrangement below, the large combinations of terms are used as x and y , while G is the slope, and N is the intercept. This of course implies that water influx term for each data point is a known value, or the simpler scenario that there is no water influx. Additionally, if the water influx is neglected in calculating the terms, the result is non-linear behavior on the plot. This can be a diagnostic to determine the presence of water drive. In practice, the scatter in the data may be great enough, and the signature of water drive subtle enough that deviation from linear behavior on the Havlena-Odeh plot may go unnoticed.

$$\frac{F - W_e B_w}{E_o + B_{oi} E_{fw}} = N + G \left(\frac{E_g + B_{gi} E_{fw}}{E_o + B_{oi} E_{fw}} \right)$$

An example of the plot is shown below. The scatter shown in the data points demonstrates the difficulty in determining trends in the reservoir behavior.



- **Movement around a** — moves the y-intercept. Changes N and keeps G (OGIP_f) constant.
- **Movement around b** — rotates the line around the pivot point. Changes N and G at the same time.
- **Movement around c** — rotates the line around the y-intercept. Changes G and keeps N constant.

The slope of the line is G and the y-intercept is N. This plot provides a solution to G and N simultaneously. Either G or N can be manually adjusted to achieve the best answer. *Care should be taken when using this plot as slight errors in pressure measurements can drastically affect results.* The data is more spread out in a cloud-like formation when errors are present in PVT or pressure data.

Note: "Scaling" applied to the plot can interfere with the appearance of a trend. Use your judgment when using this analysis.

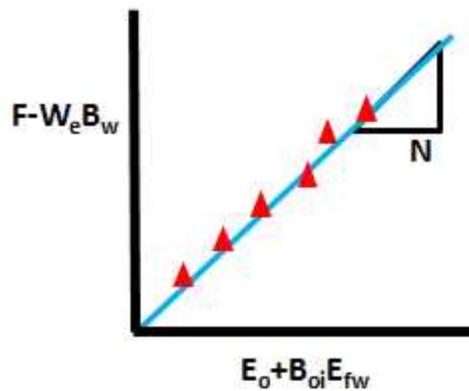
This method works for most reservoir types. In the case of an undersaturated reservoir (above bubble point), the $E_g + B_{gi} * E_{fw}$ term is zero, and this plot is not as useful. The standard Havlena-Odeh plot can be substituted for one that excludes free gas terms.

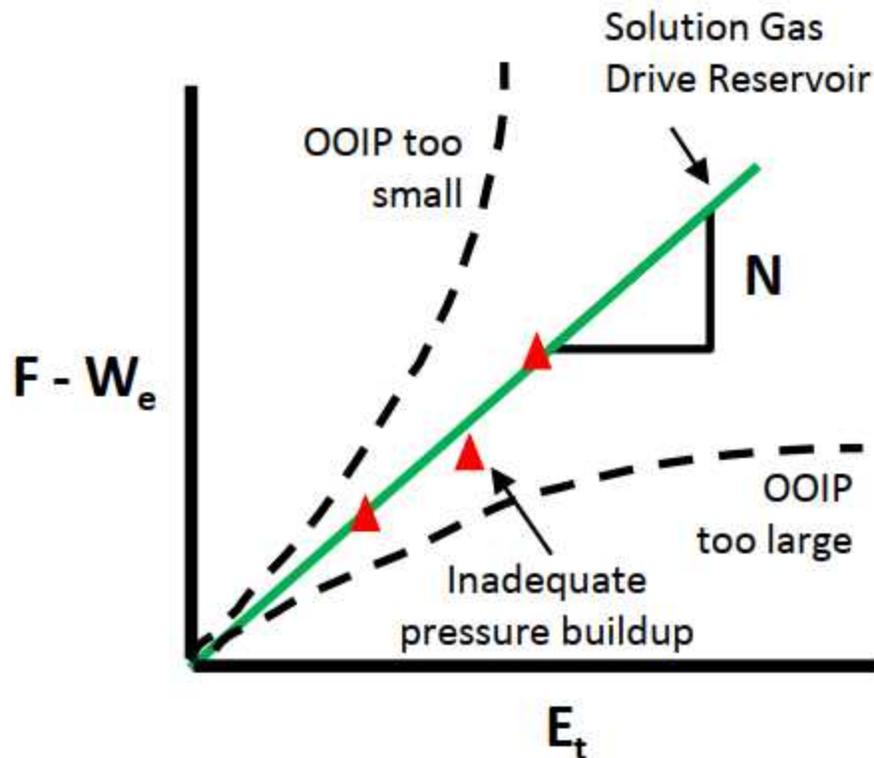
Havlena-Odeh diagnostics: F vs. E_t (no initial gas cap)

If the reservoir to be analyzed has no initial free gas, the free gas terms of the equation can be eliminated. This equation is now much simpler to linearize. In the equation shown below, the total expansion term is split into the oil and water / formation expansion terms. Once again, the inclusion of water influx is such that it is assumed to be known.

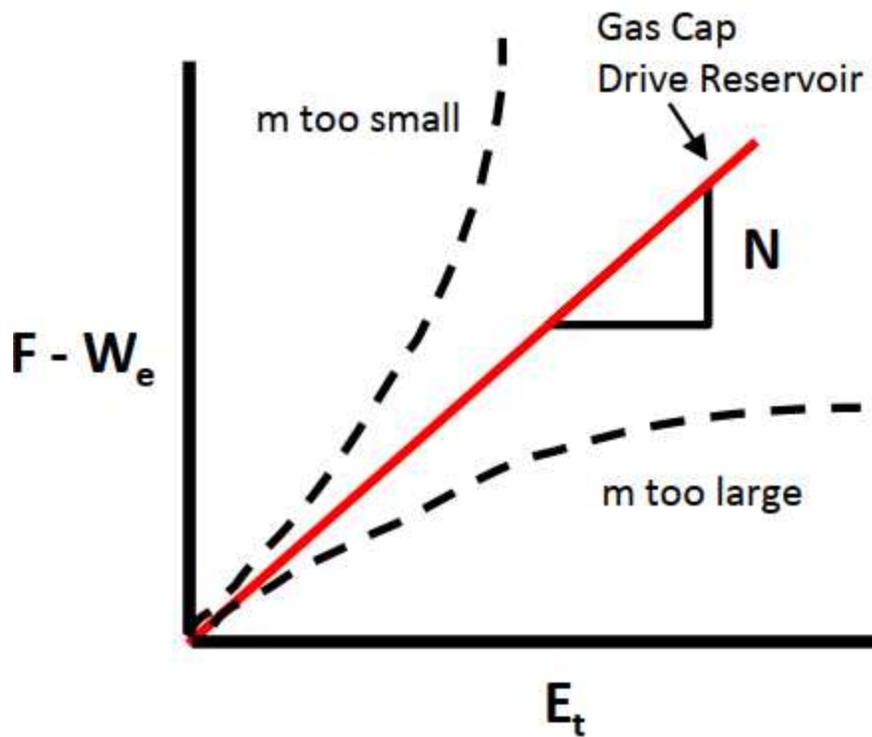
$$F - W_e B_w = N(E_o + B_{oi} E_{fw})$$

In this form of the equation, N is the slope on a plot of expansion terms versus withdrawal and influx terms. There is no intercept, so the analysis line is typically forced through zero. Similar to the Havlena-Odeh plot that includes gas terms, if water influx is neglected and a non-linear trend results, this can be a diagnostic for observing water-drive effects. An example of the plot is shown below.

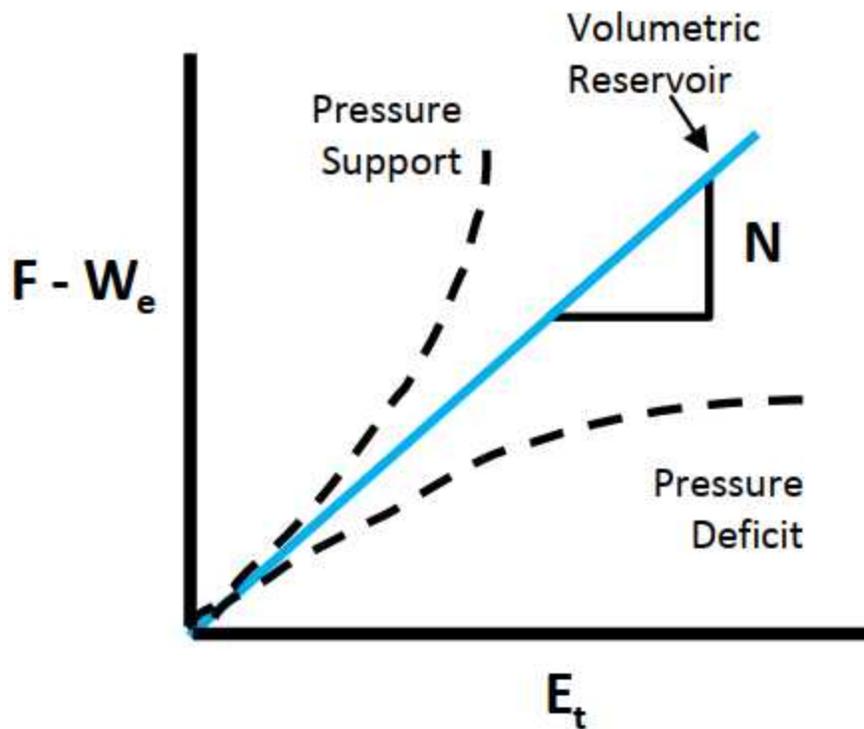




- **Linear trend** — a linear trend in the data indicates volumetric depletion behavior, or that all external drive mechanisms have been correctly accounted for.
- **Upward concave** — indicates that the OOIP is too small. Adjusting OOIP will linearize the points along the trend.
- **Downward convex** — indicates that the OOIP is too large. Adjusting OOIP will linearize the points along the trend.
- **Stray point** — an inadequate pressure buildup over time may be the reason that a pressure measurement comes in slightly below the predicted trend line. Other reasons may include inaccurate PVT data, or inaccurate production information for that time.

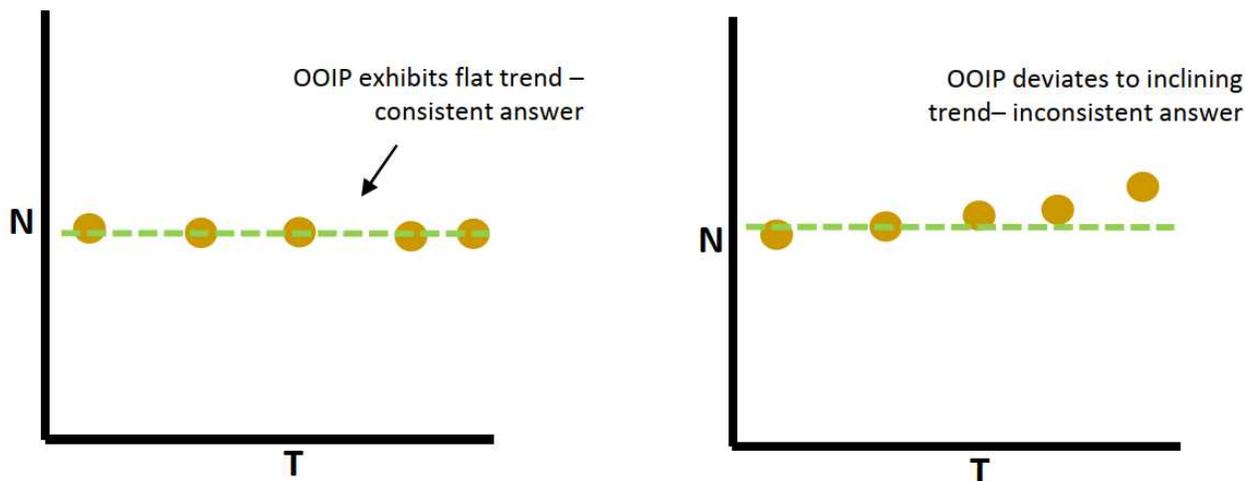


- **Linear trend** — a linear trend in the data indicates volumetric depletion behavior, or that all external-drive mechanisms have been correctly accounted for. Though it cannot independently determine the oil-in-place volume when a gas cap is present, the F vs. E_t plot can assist in confirming the consistency of the proposed solution.
- **Upward concave** — indicates that the gas cap is too small. Adjusting m or G should linearize the points along the trend.
- **Downward convex** — indicates that the gas cap is too large. Adjusting m or G should linearize the points along the trend.



- **Linear trend** — a linear trend in the data indicates a volumetric expansion reservoir (solution gas or gas cap), provided the OOIP and OGIP are correct. The F vs. E_t cannot independently determine the exact reason for pressure support, but it can assist in confirming the consistency of the solution.
- **Upward concave** — indicates pressure support from unaccounted for water injection, fluid from another reservoir, aquifer, U-tube displacement of a producing reservoir's water leg by a connected reservoir, or the expansion of water.
- **Downward convex** — indicates a pressure deficit from late-time interference from unaccounted for producing wells, rock compressibility in an over-pressurized reservoir, or inflow that gradually decreases over time due to depletion.

Oil in place diagnostics (N vs. time)

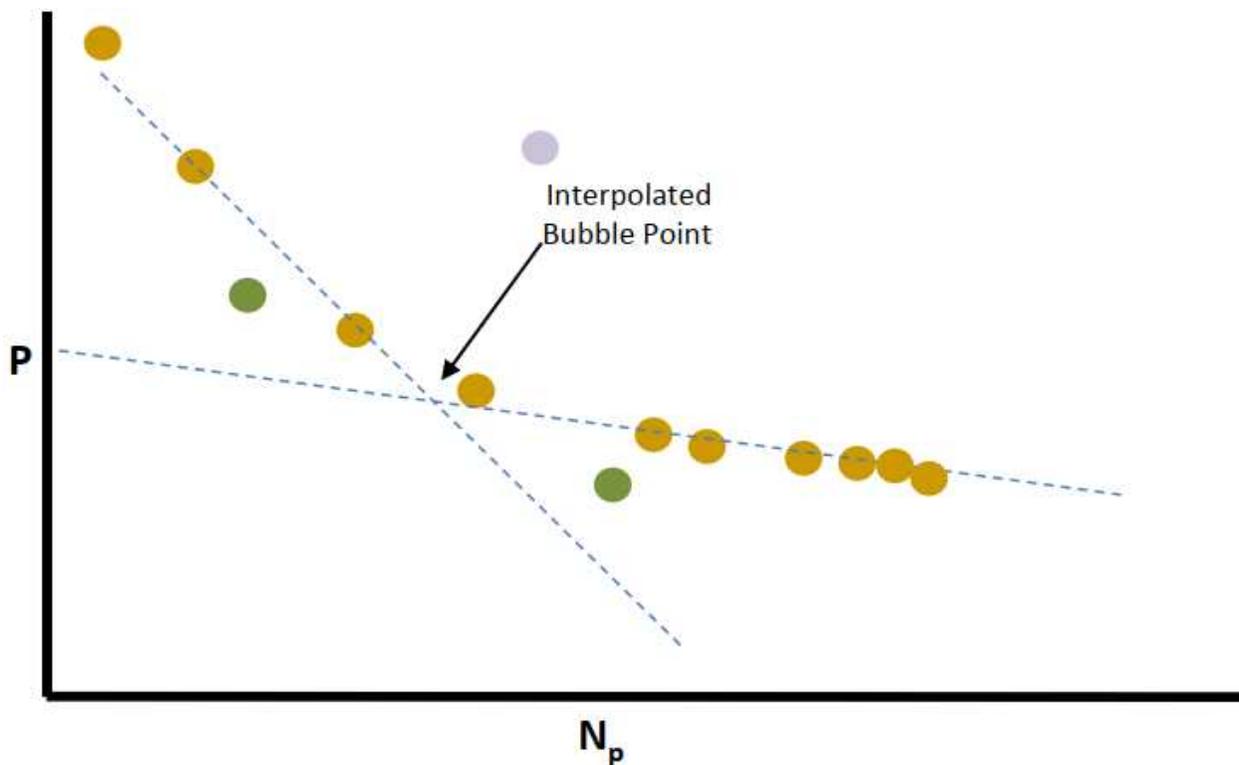


When applying material balance, it is a good practice to examine the validity of the results. The N vs. Time profile provides a useful check as to the consistency of the answer. The value of N is based on the input pressure, production, and PVT data. At each individual reservoir pressure, OOIP is calculated. An inconsistent trend in the OGIP usually indicates that there may be an external-drive mechanism present. This plot is also useful as a diagnostic to determine if the correct reservoir type has been assumed, and to assess the data quality. An inconsistent trend usually indicates that the quality of the pressure measurements are not good, or the definition of the wells in the reservoir should be reviewed. A consistent upward trend indicates that another drive mechanism may be present, whereas a downward trend indicates that not all wells in the reservoir have been included in the analysis. The type of drive mechanism is not evident, only that there is some "other" energy in the system that is not accounted for.

- **Flat trend** — a flat trend in the N values indicates volumetric depletion behavior, or that all external drive mechanisms have been correctly accounted for.
- **Inclining trend** — indicates that the reservoir is seeing additional pressure support, either from an aquifer or formation compressibility drive (geomechanical effects). However, the type of external drive mechanism is not distinguishable.

Note: This plot is meant to be used as a diagnostic guide to complement the analysis, and we recommend not putting too much emphasis on the interpretation. When there is a low frequency of pressure surveys, a trend may not be visible and this diagnostic plot may be of little value. Scaling applied to the plot can interfere with the appearance of a trend. Use your judgment when using this analysis.

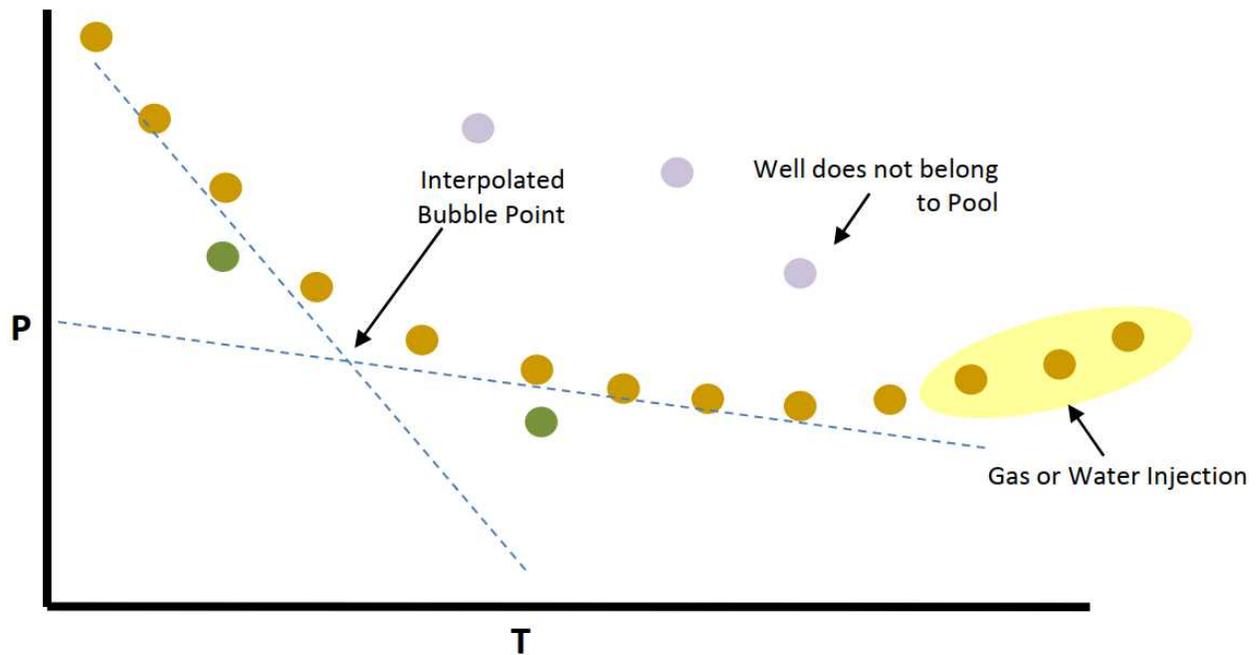
Pressure diagnostics: P vs N_p



- **Inflection** — this is where the pressure depletion trend changes. At this point, the first bubble of gas comes out of solution, and the solution-drive-energy mechanism starts to decrease, thus the reservoir depletes at a slower rate.
- **Inclining static pressures** — indicates the start of gas or water injection.
- **Constant pressure** — may indicate aquifer support.
- **Erroneous pressure data** — may indicate that this well is not part of the reservoir.

Pressure vs. time

When applying material balance, it is a good practice to initially examine the pressure depletion profile. Any changes in production during the life of the reservoir should be visible in this plot. For example, the bubble point pressure is visible by a decrease in the pressure decline rate. The start of injection should be seen as an increase in the sandface pressure measurements. Examining the trends prior to the analysis helps give a frame of reference for the analysis. With these trends, you can learn from the diagnostic plots, which can help you understand if the final answers obtained from the analysis make sense.



- **Inflection** — this is where the pressure-depletion trend changes. At this point, the first bubble of gas comes out of solution and the solution-drive-energy mechanism starts to decrease, thus the reservoir depletes at a slower rate.
- **Inclining static pressures** — indicates the start of gas or water injection.
- **Constant pressure** — may indicate that boundary-dominated flow has not yet been achieved, or the pressure of aquifer support.
- **Erroneous pressure data** — may indicate that this well is not part of the reservoir.

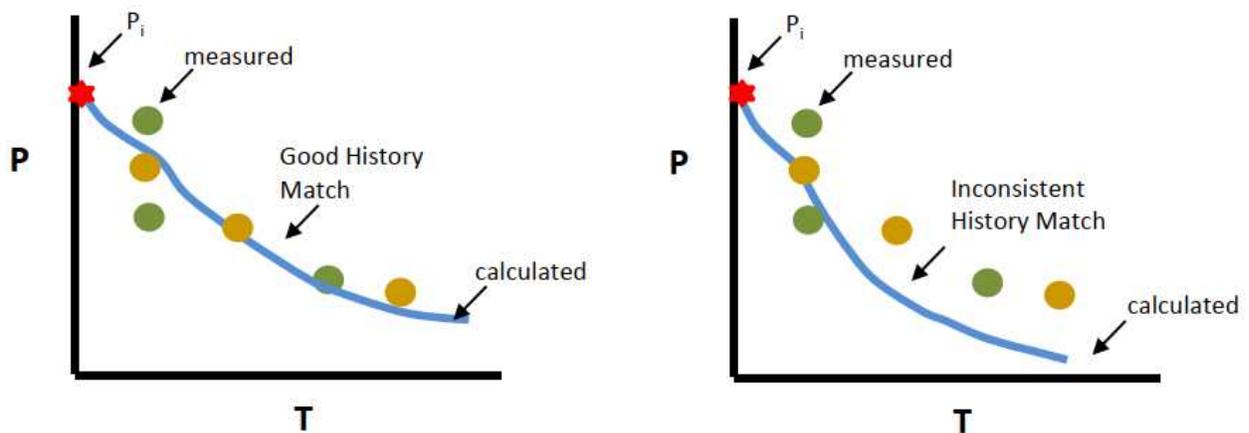
Note: This plot is meant to complement the analysis plot, and we do not recommend interpretation with pressure on its own. When there is a low frequency of pressure surveys, a trend may not be visible and this plot may be of little value.

Synthetic reservoir pressure

The pressure match method uses an iterative procedure that uses the values of original oil-in-place, original gas-in-place, and W to calculate the reservoir pressure versus time. The synthetic reservoir pressure is then plotted against the real measured static reservoir pressures and compared. This is by far the most robust and easily understood material balance technique for the following reasons:

1. Pressure and time are easily understood variables, so sensitivity analysis can be conducted relatively easily.
2. Use of time enables the analyst to see directly the impact of:
 - Changing withdrawal rates, especially shut-ins on reservoir pressure declines.
 - Injection operations on pressure response.
 - Water drive and connected reservoirs on reservoir depletion, especially since these are both cumulative withdrawal and time-based processes.
3. A relatively simple, iterative process is used to achieve a unique solution wherein:
 - Start with the simplest solution (oil and/or gas depletion only) and then proceed to more complex models only if demonstrated to be required.
 - Employ a left-to-right matching technique (early-time to late-time), wherein initial reservoir pressure is matched first, followed by early-time depletion response, and then late-time responses. Since water drive and connected reservoir models are cumulative withdrawals and time-based, their responses are minimal at early-times and maximized at late-times.

Consistent and inconsistent history matches are shown below:

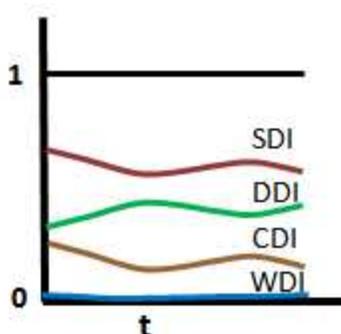


- **Good match** — the combination of G, N, and W_e has provided a valid solution to the material balance equation. Note that other combinations of values may exist as the solution is usually non-unique.

- **Incorrect / inaccurate PVT data** — results in a bad match. This causes problems early on when pressure depletion is low, and results in the oil & gas expansion terms having a large error.
- **Outlier production / pressure points** — water and solution gas may not be accounted for correctly. Also, outliers or erroneous pressure points may be incorrectly included in the analysis.
- **Incorrect pressure data** — in low permeability reservoirs, the well may not have been shut-in long enough to obtain a stabilized pressure, so pressure measurements could be on the low side.

Drive indices

Drive indices for oil reservoirs indicate the relative magnitude of the various energy sources acting in the reservoir. A simple description of a drive index is the ratio of a particular expansion term to the net withdrawal (hydrocarbon voidage). These drive indices are cumulative and change as the reservoir is produced. A plot of drive indices and the details of specific drive indices are shown below.



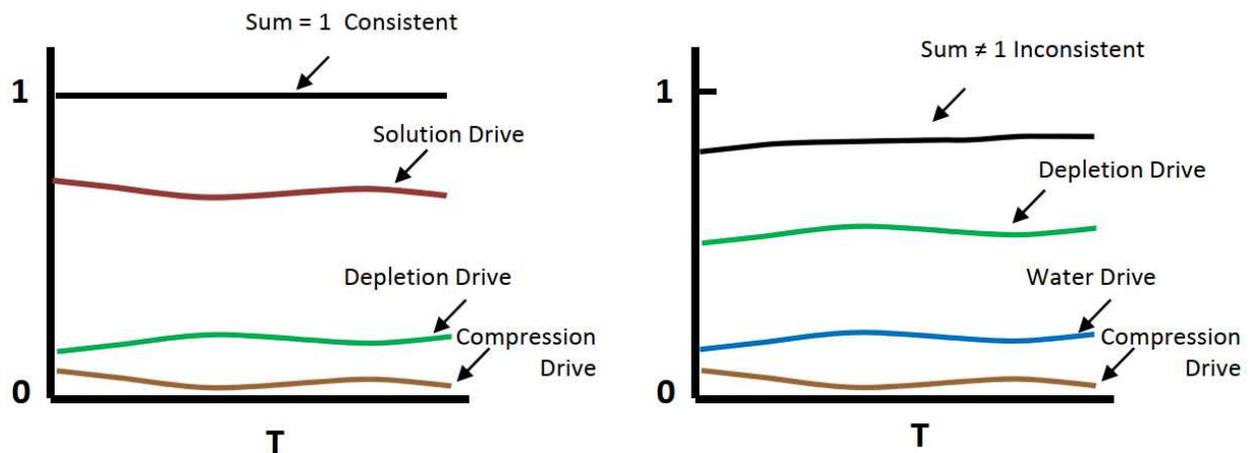
Summary

Drive Index	Description
$DDI = \frac{NE_o}{F}$	Depletion drive index
$SDI = \frac{NmE_g \left(\frac{B_{oi}}{B_{gi}} \right)}{F}$	Segregation (gas cap) drive index

Drive Index	Description
$WDI = \frac{W_e B_w - W_p B_w}{F}$	Water drive index
$CDI = \frac{N(1+m)E_{fw}B_{oi}}{F}$	Formation and connate water compressibility index

If the drive indices do not sum to unity (or very close to 1), the correct solution to the material balance has not been obtained.

Diagnostics



- **Sums to approx 1** — high probability that the correct solution to the material balance equation has been obtained.
- **Does not sum to 1** — the correct solution has not been obtained. If the summed drive indices are consistently greater than or less than unity, or show a consistent increasing or decreasing trend, this indicates that the correct solution has not been found. Possible reasons include an over-estimation of voidage, or withdrawals of energy have been defined incorrectly.

Some rules of thumb are:

- In a water-drive system, the depletion drive index should be greater than 0.2.
- In a gas-cap system, the depletion drive index should be greater than 0.65.
- In a real-life system, drive indices may not exactly sum to 1. A practical range should be between 0.95 and 1.05.

Diagnostics — Dake and Campbell

Dake and Campbell plots are used as diagnostic tools to identify the reservoir type based on the signature of production and pressure behavior. The plots are established based on the assumption of a volumetric reservoir, and deviation from this behavior is used to indicate the reservoir type.

Dake

In the Dake plot, the simplest oil case of solution gas / depletion drive (no gas cap, no water drive), is used to determine the axes of the plot. The material balance equation is rearranged as shown below.

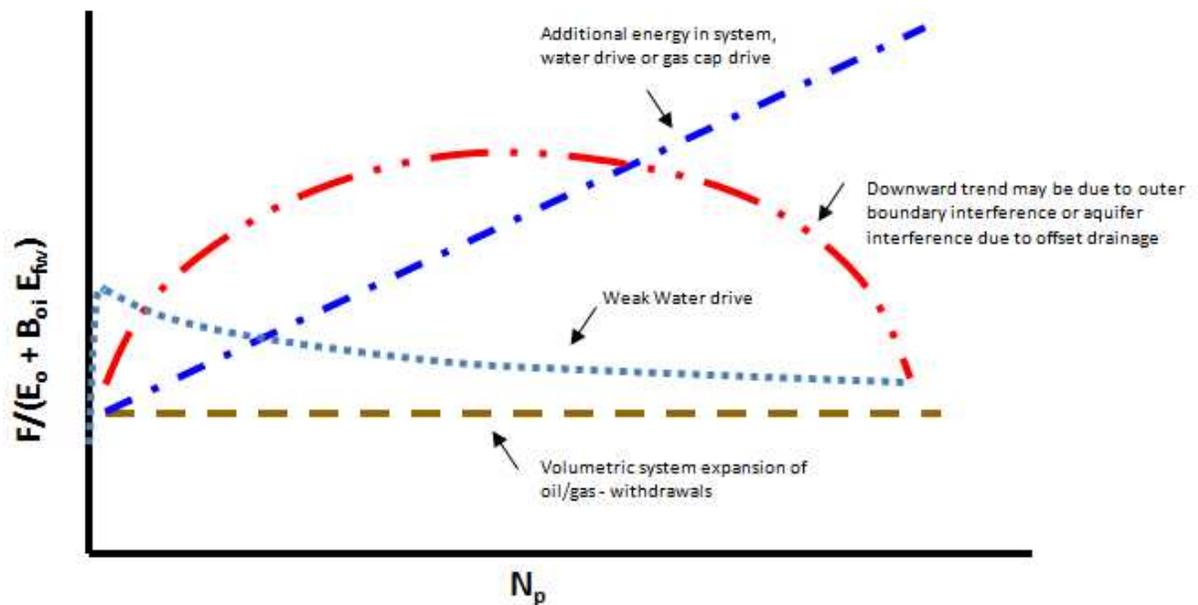
$$\frac{F}{E_o + B_{oi}E_{fw}} = N$$

In a volumetric reservoir producing due to depletion drive only, production is balanced by the oil and water / formation expansion, and the original oil-in-place is constant. If a plot of cumulative oil production versus the net withdrawal over expansion is created with this reservoir type's data, the points remain along a horizontal line.

If a gas cap is present, there is a gas expansion component in the reservoir's production. As production continues and the reservoir pressure decreases, the gas expansion term increases with an increasing gas formation volume factor. To balance this, the withdrawal over oil / water / formation expansion term must also continue to increase. Thus in the case of gas cap drive, the Dake plot shows a continually increasing trend.

Similarly, if water drive is present, the withdrawal over oil / water / formation expansion term must increase to balance the water influx. With a very strong aquifer, the water influx may continue to increase with time, while a limited or small aquifer may have an initial increase in water influx that eventually decreases.

This diagnostic assumes that the formation compressibility is constant, $cf = cfi$. This plot is meant to be diagnostic in nature, and not too much emphasis should be placed on the interpretation. It is provided as a guide to complement the analysis. In certain cases where there is a low frequency of pressure surveys, a trend may not be visible, and this diagnostic may be of little value.

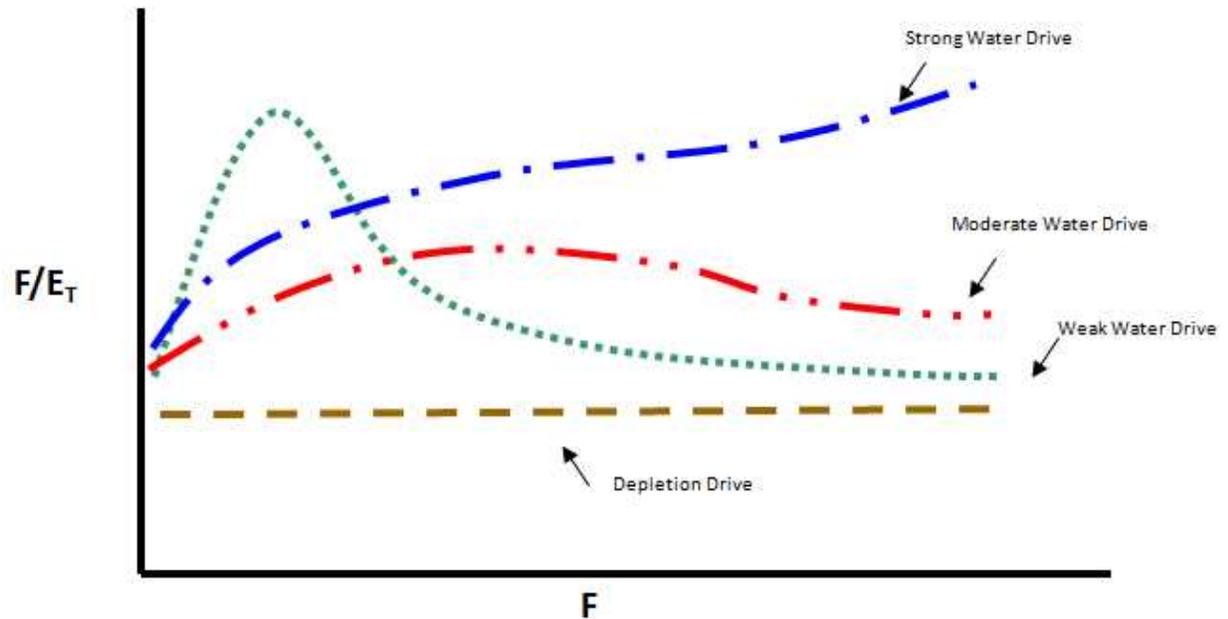


- **Horizontal straight line** — suggests a pure volumetric systems with no water influx. The energy of the reservoir is solely derived from the expansion of oil, dissolved gas in the solution, and the regular component of compaction drive.
- **Slight rising trend** — suggests the reservoir has been energized by a water influx and/or an abnormal pore compaction.
- **Steep rising trend** — suggests a strong water-drive system in which the aquifer displays infinite-acting behavior.
- **Rising then declining trend** — suggests an aquifer presence, and the effect of the outer boundary (that is, a finite aquifer). In this case, the aquifer is depleting with the reservoir itself, so the pressure support is minimal, and the external energy drive in the system is diminishing.
- **Declining trend** — suggests offset drainage or pressure depletion due to withdrawals by an offset reservoir (that is, a weak aquifer).

Campbell

The Campbell plot is a very similar diagnostic to Dake, with the exception that it incorporates a gas cap, when applicable. In the Campbell plot, the withdrawal is plotted against withdrawal over total expansion, while the water influx term is neglected. If there is no water influx, the data plots as a horizontal line. If there is water influx into the reservoir, the withdrawal over total expansion term increases proportionally to the water influx over total expansion. A weak aquifer exhibits the counter-intuitive trait of decreasing with time. The Campbell plot can be more sensitive to the

strength of the aquifer. In this version of the material balance, using only E_T neglects the water and formation compressibility (compaction) term. The Campbell plot is shown below.



- **Horizontal straight line** — suggests a pure volumetric systems with no water influx. The energy of the reservoir is solely derived from the expansion of oil, dissolved gas in the solution, and the regular component of compaction drive.
- **Slight rising trend** — suggests the reservoir has been energized by a moderate water drive.
- **Steep rising trend** — suggests a strong water-drive system in which the aquifer displays infinite-acting behavior.
- **Declining trend** — suggests a weak water drive.

Note: This plot is meant to be used as a diagnostic guide to complement the analysis, and we recommend not putting too much emphasis on the interpretation. When there is a low frequency of pressure surveys, a trend may not be visible and this diagnostic plot may be of little value.

Volatile oil — Walsh formulation

Volatile oil is also called high shrinkage crude oil, or near-critical oil. It contains relatively fewer heavy molecules and more intermediates than black oils. It has a higher API (typically greater than 44), and is typically lighter in color.

A small reduction in pressure below the bubble point causes the release of a large amount of gas in the reservoir. An additional property is used to describe volatile oil – the volatile oil ratio R_v . The volatile oil ratio describes the amount of volatilized oil in the reservoir gas phase and is typically expressed in stb/ MMscf. The volatile oil ratio is often described as "the liquid content in the gas" or the "oil vapor in the gas". An oil reservoir can be described as volatile, if the gas in the gas cap or the gas that comes out of solution contains significant quantities of volatile liquids. Volatile oils normally contain more than 500scf/ stb of dissolved gas and the liquid content of the gas phase, the volatile oil ratio, would be more than 20stb/ MMscf.

Regular material balance does not account for volatile oil. In a reservoir containing volatile oil, the Walsh formulation is used to calculate original oil-in-place. The equations which are modified from standard material balance are shown below.

Terms	Description
$F = N_p \left(\frac{B_o - B_g R_s}{1 - R_v R_s} \right) + G_p \left(\frac{B_g - R_v B_o}{1 - R_v R_s} \right) + W_p B_w - W_{inj} B_{winj} - G_{inj} B_{ginj}$	Modified drawal term for volatile oil.
$E_o = \frac{(B_o - B_{oi}) + B_g (R_{si} - R_s) + R_v (B_{oi} R_s - B_o R_{si})}{1 - R_v R_s}$	Modified oil expansion term for volatile oil.
$E_g = \frac{(B_g - B_{gi}) + B_o (R_{vi} - R_v) + R_s (B_{gi} R_v - B_g R_{vi})}{1 - R_v R_s}$	Modified gas expansion term for volatile oil.

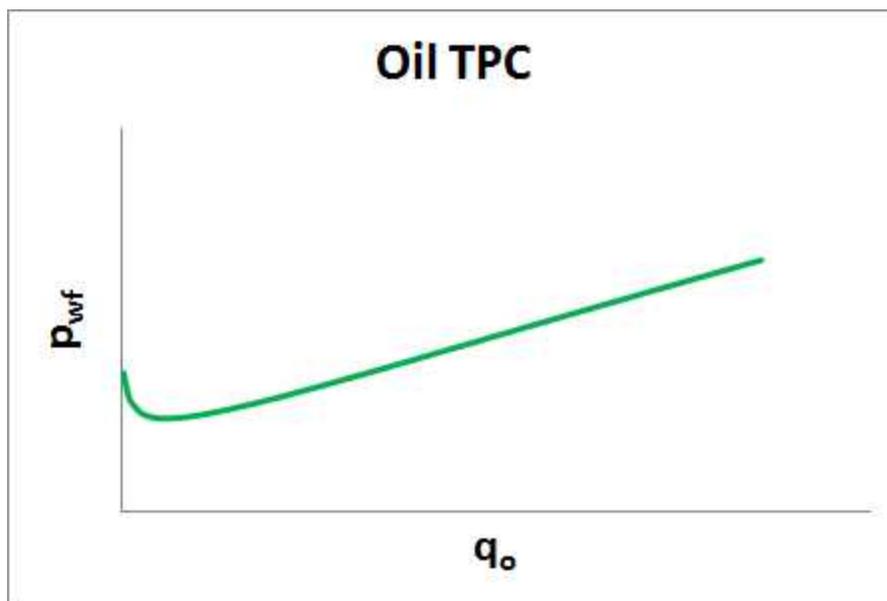
Oil IPR / TPC theory

When the objective is to determine the optimal way to complete a well, a common method is nodal analysis. Nodal analysis combines two separate concepts, inflow performance relationship (IPR) and tubing performance curve (TPC), and plots them on the same chart where you can see

how each well may operate under a number of conditions. Since both the IPR and TPC are calculated independently, the theory for each concept is described separately below. For information on this analysis, see [Oil IPR / TPC](#).

TPC

A TPC is a graphical representation of the pressure response of a wellbore completion to a range of fluid rates. The TPC is plotted as a relationship between sandface flowing pressure versus oil rate.



The inputs needed to create a TPC are as follows:

- Wellhead pressure
- Ratios (GOR and WOR)
- A valid wellbore configuration
See the [Wellbore editor](#) for details.
- Valid fluid properties
See the [Properties editor](#) for details.

Using these inputs, a series of [pressure loss calculations](#) are done over a range of oil rates, and then a line is drawn through all the points to create a curve. The default setting is to plot 64 points, using equally spaced oil rates up to a maximum rate. The maximum oil rate is defined by the largest IPR.

IPR

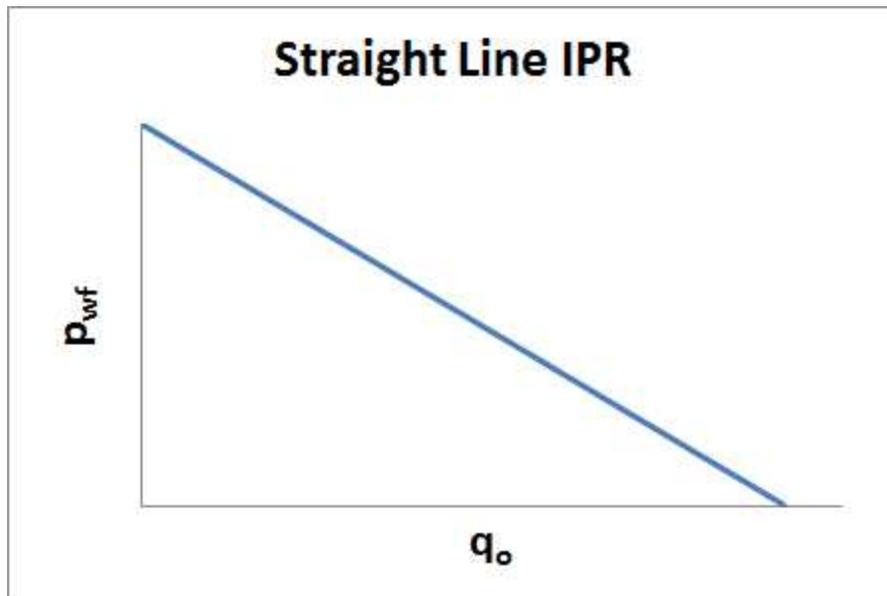
Flow into a well depends on both the reservoir characteristics and the sandface flowing pressure. The relationship of inflow rate to sandface flowing pressure is called the inflow performance relationship (IPR). Harmony Enterprise presents this relationship in the form of a pressure versus flow rate plot. From this plot, the well's flow potential can be determined at various flowing sandface pressures.

Straight line IPR

In calculating oil well production, it is assumed that producing rates are proportional to the pressure drawdown. Using this assumption, a well's behavior can be described by its productivity index (PI) as follows:

$$PI = \frac{q}{(P_R - P_{wf})}$$

This relationship was developed from Darcy's law for the steady-state radial flow of a single, incompressible liquid. An example of a straight line IPR is shown below.



In order for oil to flow from the surrounding reservoir towards the wellbore, there must be a pressure drawdown. Consequently, if the flowing sandface pressure (p_{wf}) is equal to the reservoir pressure (p_R), then no oil flows from the reservoir to the wellbore, and therefore the rate is zero. Consequently, for any IPR plot, the y-axis intercept is essentially an indicator of the reservoir pressure.

Likewise, if the sandface pressure is zero, then the drawdown would be at its maximum value, indicating the theoretical maximum rate that the reservoir could deliver to the well. This maximum rate is sometimes referred to as the absolute open flow potential (AOFP), and is indicated by the x-axis intercept on the plot. Since an absolute sandface pressure of zero is a physical impossibility, the AOFP cannot be measured. Instead, a test is performed to measure the rate that the reservoir delivers at some intermediate sandface pressure. This test information, along with the reservoir pressure, is used to determine the productivity index. Consequently, the AOFP can be calculated from the productivity index equation.

Vogel IPR

While a straight line IPR is quite applicable for single-phase liquid systems (for example, a water reservoir), it is less accurate for two-phase systems. Since reservoir oil contains dissolved natural gas, and this gas evolves from the oil below the bubble point pressure (p_{bp}), a two-phase scenario is a common occurrence in an oil reservoir.

Vogel developed the following empirical equation to account for two-phase flow.

$$\frac{q_o}{(q_o)_{max}} = 1 - 0.2 \left(\frac{p_{wf}}{p_R} \right) - 0.8 \left(\frac{p_{wf}}{p_R} \right)^2$$

where:

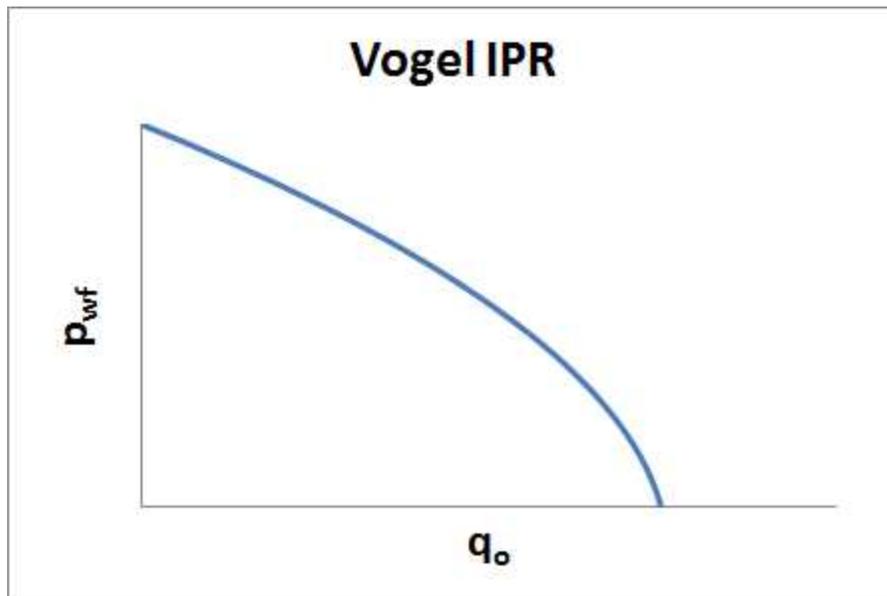
q_o = Oil rate, stb/d

$(q_o)_{max}$ = Maximum oil rate, stb/d

p_{wf} = Flowing sandface pressure, psi(a)

p_R = Average reservoir pressure, psi(a)

An example is shown below.



IPR with single-phase and two-phase flow

Vogel's equation was derived for reservoirs where the bubble point pressure was equal to the reservoir pressure. For undersaturated reservoirs (that is, where reservoir pressure is higher than bubble point pressure), the straight line IPR equation applies for sandface pressures above p_{bp} while the Vogel IPR equation applies for pressures below p_{bp} .

Liquid Composite IPR

The liquid composite IPR method can be used to account for both oil and water flow in the reservoir. The oil IPR is determined from Vogel's equation, whereas the water IPR is determined using a straight-line (productivity index) equation. Both oil and water IPRs are added together to determine the liquid IPR.

A complete discussion and derivation of the equations is detailed in "The Technology of Artificial Lift Methods," Volume 4, pages 30-35 by Kermit E. Brown 1984 PennWell Publishing.

Custom IPR best-fit algorithms

With a [Harmony Optimize license](#), there are several methods to best-fit custom data points for an IPR. All methods require that you input the current reservoir pressure, and that the oil properties have a valid entry for bubble-point pressure.

Vogel-based fit

This method matches your data to the Vogel and straight-line IPR equations described above. A minimum of one data point is required.

Fetkovich-based fit

This method matches your data to the Fetkovich equation. A minimum of two data points are required. The generalized Fetkovich equation is as follows:

$$q_o = J_{sat} (p_R^2 - p_{wf}^2)^n$$

where:

q_o = Oil rate, stb/d

J_{sat} = Productivity index , stb/d/psi(a)ⁿ

p_{wf} = Flowing sandface pressure, psi(a)

p_R = Average reservoir pressure, psi(a)

n = Flow exponent

Linear fit

This method draws an IPR as a series of straight lines between each entered data point. This simple fit does not extrapolate input points to maximum rate, and does not allow for an increase in slope (off-trend data points). However, a linear fit can honor the counter-intuitive test points taken from transient and low-permeability wells more closely than with the empirical-based fits.

Numerical model theory

Background

There are two main types of models used to simulate the flow of fluid through porous media: analytical models and numerical models. Both types have their advantages and disadvantages.

Analytical models

Analytical models have relatively short calculation times, so you can history match with these models quickly. More than that, you can even match the model automatically using automatic

parameter estimation (APE).

The main disadvantage for these models is that they can only simulate single-phase flow – either liquid or gas, but not gas and liquid flowing together. Additionally, analytical models do not fully account for changing fluid properties with pressure. In case of liquid flow, fluid properties are assumed to be constant, and in case of gas flow, the change of fluid properties with pressure is accounted for by using pseudo-pressure and pseudo-time.

Unfortunately, pseudo-time is not an exact transformation. As a result, changing gas properties are only accounted for to a certain extent. Therefore, in cases where pressure varies significantly across the reservoir (for example, pays with low permeability), long-term forecasts for gas analytical models may be inaccurate. There is no known way to fully account for the change in fluid properties when using analytical models.

Numerical models

The numerical models have been significantly improved in Harmony Enterprise. One of the key benefits is the improvement in computation time, so that the model runs almost as fast as an analytical model. These modifications include:

- using the pseudo-pressure formulation
- optimized "gridding" — by using the pseudo-pressure formulation, you can use larger grid cells without affecting the accuracy of calculation results; using larger grid cells also makes calculations run faster.

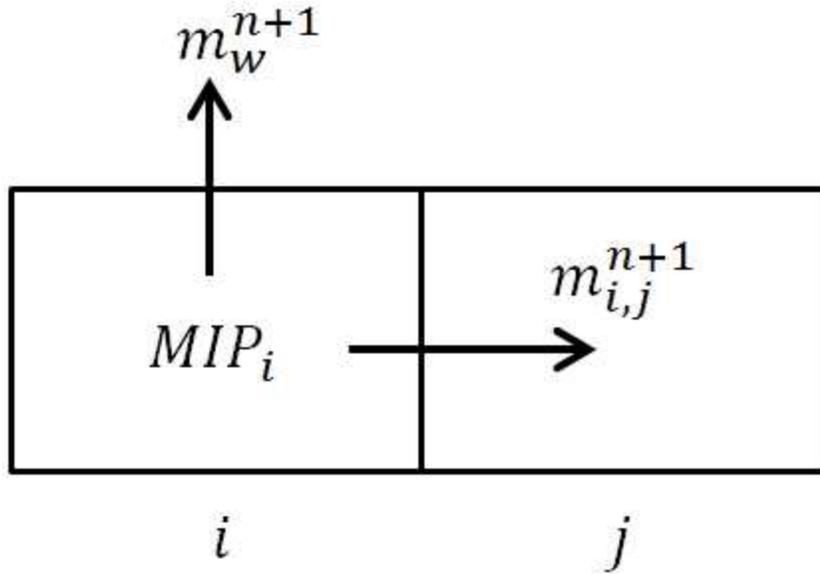
With numerical models, you can model multiphase flow, and account for changing properties of each phase, and the interaction between phases.

The main disadvantage for these models is their long computation time. With the numerical model, the reservoir is divided into a number of cells, and then the flow is modeled simultaneously in all cells. To be able to assume constant pressure and constant fluid properties within each cell, the size of each cell needs to be relatively small. Therefore, the number of cells required for an accurate solution becomes large, which results in a long computation time. Note that decreasing the number of cells to reduce computation time may significantly affect calculation results.

Performing a manual history match for numerical models is time consuming. In addition, an automatic history match for numerical models is complicated, and thus not widely available in commercial software.

General formulation for the single-phase model

To calculate pressure across the reservoir, we divide it into a number of grid cells. At each timestep ($n+1$), we formulate a material balance for each cell.



To define components of mass balance for cell i at timestep $n+1$:

Mass in place (MIP) for cell i at timestep $n+1$ can be calculated as:

Equation 1

$$MIP_i^{n+1} = MIP_i(p_i^{n+1}) = V_{bi}\varphi(p_i^{n+1})\rho(p_i^{n+1})$$

where:

V_{bi} = bulk volume for cell i

p_i^{n+1} = pressure for cell i at timestep $n+1$

φ = porosity

ρ = density

Mass flow from cell i to the adjacent cell j during timestep $n+1$ can be calculated as:

Equation 2

$$m_{i,j}^{n+1} = \rho(p) q_{i,j}^{n+1} \Delta t = \frac{A_{i,j} k}{L_{i,j}} \frac{\rho(p) k_m(p)}{\mu(p)} (p_i^{n+1} - p_j^{n+1}) \Delta t$$

(We used Darcy's Law to calculate flow rate.)

In equation 2:

$q_{i,j}^{n+1}$ = flow rate from cell i to cell j at timestep $n+1$

$A_{i,j}$ = cross-section area between cells i and j

$L_{i,j}$ = distance between the centers of cells i and j

μ = viscosity

k = permeability at the initial pressure

$k_m(p)$ = permeability multiplier (permeability at a certain pressure is calculated as $k_{effective} = k \cdot k_m(p)$).

Mass produced at the well during timestep $n+1$ (if well penetrates cell i) can be calculated as:

Equation 3

$$m_{i,w}^{n+1} = \rho(p) q_{i,w}^{n+1} \Delta t = WI \frac{\rho(p) k_m(p)}{\mu(p)} (p_i^{n+1} - p_{wb}^{n+1}) \Delta t$$

where:

WI = wellbore index (as per Peaceman 1978 or Babu and Oden, 1989)

p_{wb}^{n+1} = pressure at the wellbore at timestep $n+1$

Material balance for cell i at timestep n can be written as:

Equation 4

flow to other cells *flow to the well* *change in mass in place*

$$\sum_j m_{i,j}^{n+1} + m_{i,w}^{n+1} = MIP_i (p_i^{n+1}) - MIP_i (p_i^n)$$

Using equations 1, 2, and 3, and bringing all the terms to the left, we can rewrite equation 4 as:

Equation 5

$$\sum_j \left(\frac{A_{i,j} k_{\rho(p)} k_m(p)}{L_{i,j} \mu(p)} (p_i^{n+1} - p_j^{n+1}) \Delta t \right) + WI \frac{\rho(p) k_m(p)}{\mu(p)} (p_i^{n+1} - p_{wb}^{n+1}) \Delta t - (V_{bi} \varphi(p_i^{n+1}) \rho(p_i^{n+1}) - V_{bi} \varphi(p_i^n) \rho(p_i^n)) = 0$$

Assuming that the pressure distribution has been calculated for timesteps 1, 2, ... n , to calculate pressure distribution at timestep $n+1$, we formulate material balance (equation 5) for each cell, and solve all these equations simultaneously. Unknowns of the system are p_i^{n+1} for each cell i ; therefore, the number of equations is the same as the number of unknowns, and the system can be solved.

Well constraint considerations

For a well producing at a specified sandface pressure, the described system of equations can be used directly (because p_{wb}^{n+1} is known). However, for a well that produces at a specified surface q , an extra equation is required.

Equation 6

$$\sum_i \left(WI_i \frac{\rho(p) k_m(p)}{\mu(p)} (p_i^{n+1} - p_{wb}^{n+1}) \right) = q \rho_{sc}$$

where:

i = summation index for all cells penetrated by the well

ρ_{sc} = fluid density at standard conditions

TPC stabilization

Tubing performance curve (TPC) stabilization is applied when the deliverability of the model intersects with the well's TPC curve at a point where the slope is negative (found at low rates). This portion of the TPC is generally characterized by unstable, slugging flow.

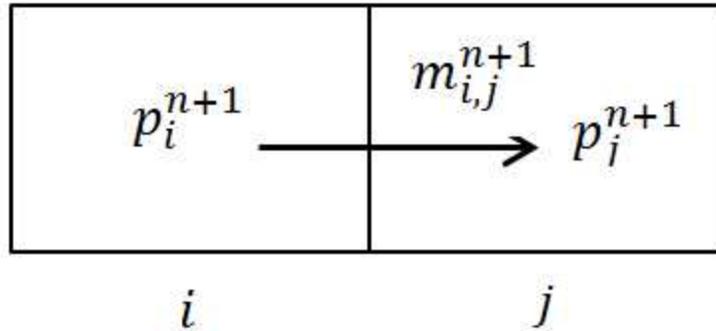
When the resultant operating point is found to be in this unstable section, the numerical model can respond with a series of shut-ins and intermittent production.

TPC stabilization switches the forecast reference point from wellhead to sandface, allowing the forecast to continue with a constant sandface pressure equal to the minimum sandface pressure of the TPC.

This stabilization can be deselected in the Options dialog box, Numerical node.

Considerations when estimating fluid properties

In the above formulation, we use rock and fluid properties estimated at certain pressures. The term $\frac{\rho(p)k_m(p)}{\mu(p)}$ is used in $m_{i,j}^{n+1}$ (equation 2) and in $m_{i,w}^{n+1}$ (equation 3).



Some logical questions are:

- At what pressure should we estimate this term?
- Should we use pressure in one of the cells, or some kind of average?

Fluid properties may significantly vary with pressure (especially if the modeled fluid is gas); therefore, selecting the correct way of estimating properties becomes important.

In classical numerical simulation (including numerical models in single-user Harmony), properties are estimated at the pressure of the upstream cell (that is, the cell with the higher pressure). For such a simulation to be accurate, you should ensure that properties in the adjacent cells are close. To achieve this, grid cells have to be small enough. Unfortunately, having smaller grid cells results in longer computation times.

With the numerical model in Harmony Enterprise (both for single-well and multi-well), we use the pseudo-pressure formulation to estimate fluid properties and calculate mass transfers.

Numerical model pseudo-pressure definition

The numerical model pseudo-pressure is defined as:

Equation 7

$$\psi_h(p) = \int_0^p \frac{\rho(p)k_m(p)}{\mu(p)} dp$$

Note: For gas, the definition of numerical model pseudo-pressure is very similar to a traditional pseudo-pressure. To see this, express density as $\rho = \frac{pM}{zRT}$ (z = gas compressibility factor, T = temperature, R = gas constant, M = molar mass). This results in the following equation:

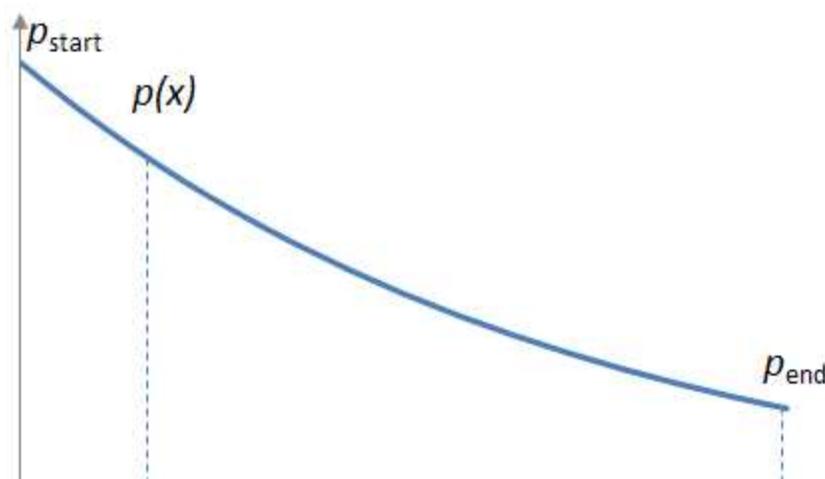
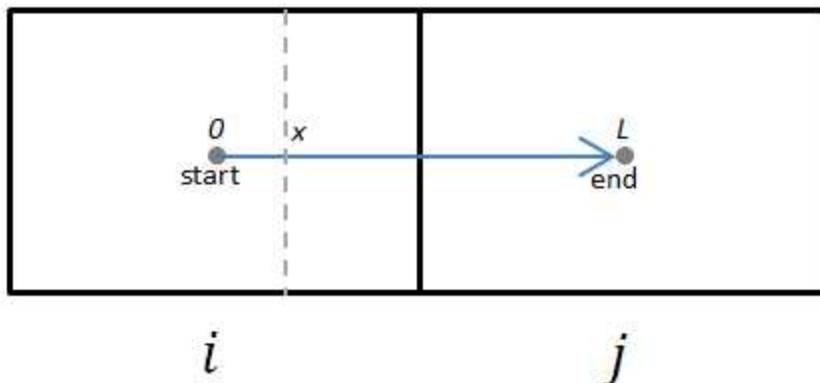
Equation 8

$$\psi_h(p) = \int_0^p \frac{\rho(p)k_m(p)}{\mu(p)} dp = \frac{M}{2RT} \int_0^p \frac{k_m(p)p}{z(p)\mu(p)} dp = \frac{M}{2RT} \psi(p)$$

Therefore, the numerical model pseudo-pressure and traditional pseudo-pressure are different by a constant factor.

Numerical model pseudo-pressure formulation

As was mentioned in considerations when estimating fluid properties, the calculation of mass flow from one cell to another given in equation 2 has a deficiency: it does not account for a variation of fluid properties with pressure. The numerical model formulation modifies equation 2 to get a relationship between the mass flow rate and pressure drop when properties are changing with pressure.



At each cross-section at any given distance (x), the pressure gradient across the cross-section can be expressed using the differential form of Darcy's Law:

Equation 9

$$-\frac{dp}{dx} = q \cdot \frac{\mu(p(x))}{k \cdot k_m(p(x)) \cdot A} = \underbrace{\frac{(m/\Delta t)}{\rho(p(x))}}_q \cdot \frac{\mu(p(x))}{k \cdot k_m(p(x)) \cdot A}$$

where $(m/\Delta t)$ is the mass flow rate across the cross-section. This can be rearranged as:

Equation 10

$$\frac{(m/\Delta t)}{Ak} = - \frac{\rho(p(x))k_m(p(x))}{\mu(p(x))} \frac{dp}{dx}$$

Integrating both parts from 0 to L with respect to x , and using the left-side of the equation is a constant with respect to x , we get the following equation:

Equation 11

$$\frac{(m/\Delta t)}{Ak} \cdot L = - \int_{x=0}^{x=L} \frac{\rho(p(x))k_m(p(x))}{\mu(p(x))} \frac{dp}{dx} dx = - \int_{p_{start}}^{p_{end}} \frac{\rho(p)k_m(p)}{\mu(p)} dp = \psi_h(p_{start}) - \psi_h(p_{end})$$

Note: We used the definition given in [equation 7](#) for the last transformation.

To summarize, when fluid properties are changing with pressure, the mass flow rate through the cross-section can be calculated as:

Equation 12

$$m/\Delta t = \frac{Ak}{L} \left(\psi_h(p_{start}) - \psi_h(p_{end}) \right)$$

Therefore, [equation 2](#) can be modified to account for changing properties. The mass flow from cell i to cell j during timestep $n+1$ is calculated as:

Equation 13

$$m_{i,j}^{n+1} = \frac{Ak}{L} \left(\psi_h(p_i^{n+1}) - \psi_h(p_j^{n+1}) \right) \Delta t$$

Equation 3 can be modified in a similar fashion. Mass produced at the well during timestep $n+1$ is calculated as:

$$m_{i,w}^{n+1} = WI \left(\psi_h(p_i^{n+1}) - \psi_h(p_{wb}^{n+1}) \right) \Delta t$$

As a result, the material balance equation for each cell (equation 5) is modified to:

Equation 14

$$\sum_j \left(\frac{A_{i,j}k}{L_{i,j}} \left(\psi_h(p_i^{n+1}) - \psi_h(p_j^{n+1}) \right) \Delta t \right) + WI \left(\psi_h(p_i^{n+1}) - \psi_h(p_{wb}^{n+1}) \right) \Delta t - \left(V_{bi} \varphi(p_i^{n+1}) \rho(p_i^{n+1}) - V_{bi} \varphi(p_i^n) \rho(p_i^n) \right) = 0$$

Assuming that the pressure distribution has been calculated for timesteps 1, 2, ... n , to calculate pressure distribution at timestep $n+1$, we formulate a modified material balance (equation 14) for each cell, and solve all these equations simultaneously. Unknowns of the system are p_i^{n+1} for each cell i ; therefore, the number of equations is the same as the number of unknowns, and the system can be solved.

Note: Well constraints are treated in a similar way to general numerical model formulations.

Modifications for the multiphase model

In the case where there are two or three phases flowing together, the multiphase solution follows similar logic as single-phase flow, with a few modifications.

- The mass balance equation (equation 4) has to be modified to account for the fact that fluid can change from one phase to another (e.g., oil can evaporate and become gas, or gas can condense to liquid).
- In the single-phase case, the mass balance equation is written for each cell; therefore, we get n equations (where n is the number of cells). In the multiphase case, the mass balance equation is written for each cell for each phase; therefore, we get $n \cdot$ "number of phases" as equations.
- In the single-phase case, the unknowns of the system are pressures in each cell; therefore, we get n unknowns. In the multiphase case, the unknowns of

the system are pressures in each cell (n), and saturations for each cell; therefore, we get total $n \cdot$ "number of phases" as unknowns. (We use the fact that the sum of all saturations is equal to 1 for any of the grid cells.)

- When calculating a mass transfer from one cell to another ([equation 2](#)) and a mass transfer from the cell to the well ([equation 3](#)), we have to account for relative permeability.
- For the single-phase case, we re-write the mass transfer term in terms of pseudo-pressure ([equation 13](#)). In the multiphase case, we can do the same thing, but there will be different pseudo-pressure functions for different phases. (The pseudo-pressure formulation for each phase follows the definition given in [equation 7](#), but ρ , μ , and k are different for different phases.)
- For the single-phase case, the system of equations can be solved in terms of pseudo-pressures (the unknowns are pseudo-pressures in each cell). For the multiphase case, equations have to be solved in terms of pressure (the unknowns are pressures and saturations in each of the cells). The pseudo-pressure formulation is only used to calculate mass transfer between cells.

Advantages of using the pseudo-pressure formulation

Pseudo-pressure formulation makes simulation significantly faster than classical numerical simulation modeling for the following reasons:

1. **Smaller number of grid cells:** In classical numerical simulation, grid cells have to be small enough to consider constant fluid properties within each cell. Pseudo-pressure formulation accounts for a variation of fluid properties between the centers of two adjacent cells; therefore, it is possible to have larger grid cells. By having a smaller *number of grid cells*, calculation speed increases.
2. **Faster solution for a non-linear system:** While performing numerical modeling, [equation 5](#) is solved at each timestep. This system of equations is non-linear; therefore, it is solved iteratively, using the Newton-Raphson method. This method involves calculating derivatives of each matrix element with respect to each unknown. Calculating these derivatives is faster for pseudo-pressure formulation ([equation 14](#)), because we have to deal with one fluid property function ($\Psi_h(\mathbf{p})$) as opposed to a combination of three functions ($\rho(\mathbf{p})$, $k_m(\mathbf{p})$, $\mu(\mathbf{p})$) for traditional formulation. More than that, due to the integral nature of $\Psi_h(\mathbf{p})$, its derivative is calculated easily.

Modifications for multi-well models

Multi-well models in Harmony Enterprise are multi-phase numerical models. They use the same calculation engine and the same formulation as is used by single-well numerical models that is

described above. However, the gridding is adjusted to include multiple wells and gridding is done differently for different completion types.

Since multi-well models allow multiple layers, additional modifications are made to model flow in a vertical direction, and to model layers that are connected through the wellbore.

Modifications for flow in a vertical direction

Re-writing Equation 2 for each phase individually, the mass flow rate of phase x from cell i to the adjacent cell j during a particular timestep, can be calculated as:

Equation 15

$$\frac{m_{x\ i,j}}{\Delta t} = \frac{A_{i,j} k_{abs} \rho_x(p) k_{rx}(S_x) k_m(p)}{L_{i,j} \mu_x(p)} (p_i - p_j)$$

Where k_{rx} is a relative permeability and the remaining variables are the same as defined in Equation 2.

To account for the fact that the direction of flow may have a vertical component, the equation should be adjusted as:

Equation 16

$$\frac{m_{x\ i,j}}{\Delta t} = \frac{A_{i,j} k_{abs} \rho_x(p) k_{rx}(S_x) k_m(p)}{L_{i,j} \mu_x(p)} (p_i - p_j - \rho_x(p)gh)$$

Where h is a vertical distance between the centers of cells i and j .

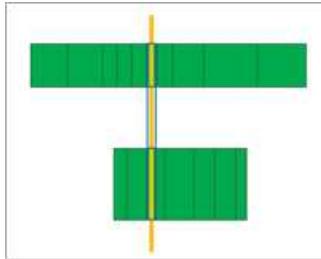
Note: If the direction of flow is horizontal ($h=0$), Equation 16 reduces to Equation 15. When there is no flow in the system, Equation 16 reduces to: $p_i - p_j = \rho_x gh$. In other words, each phase is in hydrostatic equilibrium.

Modifications for modeling layers connected through the wellbore

The conventional multi-well (CMW) model enables you to model layers that are connected only through the wellbore. In this case, the model has equations for all of these cells solved simultaneously:

- Reservoir cells in each of the layers (marked as rectangles with a thin black outline)

- Cells representing the wellbore (marked as rectangles with a thick blue outline)



Reservoir cells are connected to each other and the flow rate through each connection is governed by Equation 16.

Reservoir cells are also connected to wellbore cells and the flow rate through each connection is governed by Equation 16, using the wellbore index WI, instead of:

$$\frac{A_{i,j} k_{abs}}{L_{i,j}}$$

Wellbore cells are also connected to each other, but this connection is different, because flow in this connection represents flow of the fluid in the pipe, not in the porous media. Phases inside the wellbore are assumed to be mixed and to flow as a single homogeneous fluid.

Based on a fully mixed assumption, the density of the mixture is calculated as:

Equation 17

$$\rho_{mix} = \rho_o * S_o + \rho_g * S_g + \rho_w * S_w$$

And viscosity of the mixture is calculated as:

Equation 18

$$\mu_{mix} = \mu_o^{S_o} * \mu_g^{S_g} * \mu_w^{S_w}$$

The volumetric flow rate of the mixture is then calculated as per Darcy's law:

Equation 19

$$q_{mix} = \frac{T_m}{\mu_{mix}} * (P_i - P_j - \rho_{mix}gh)$$

Where T_m is a high number to represent the high conductivity of the pipe.

This rate can then be split into rates for individual phases:

Equation 20

$$q_o = q_{mix} * S_{o,upstream}, \quad q_g = q_{mix} * S_{g,upstream}, \quad q_w = q_{mix} * S_{w,upstream}$$

Note that since T_m is a very high number, Equation 19 results in this pressure drop across the pipe segment:

Equation 21

$$p_i - p_j = \rho_{mix}(p)gh + \frac{q_{mix}\mu_{mix}}{T_m} \approx \rho_{mix}gh$$

Therefore, pressure drop across the wellbore calculated using this approach approximately equals the hydrostatic pressure drop for a homogeneous mixture.

Numerical URM theory

The numerical unconventional reservoir model (URM) analysis was developed based on [URTeC-2020-2967-MS](#) and accounts for multiphase behavior, including total compressibility change when pressure drops below saturation pressure. Similar to the traditional URM analysis, numerical URM is used to determine the following: the linear flow parameter (LFP or $Ac\sqrt{k}$) and the size of [SRV](#) (A_{SRV} or $OFIP_{SRV}$).

Summary of methodology

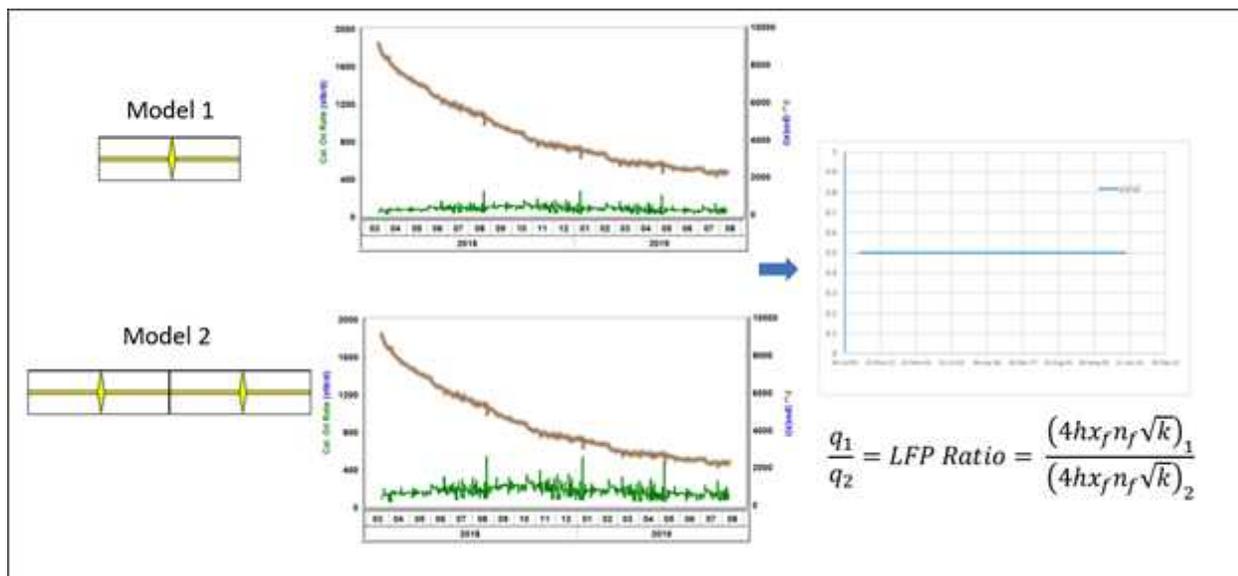
Consider two similar models for a horizontal multi-fractured well. Both models have:

- SRV geometry (exhibit linear flow followed by boundary dominated flow)
- same initial pressure
- same PVT properties
- same relative permeability curves
- same porosity and initial saturations
- pressure control calculation (using same historical pressures)

However, these two models may have different LFP (Linear Flow Parameter = $4hx_f n_f \sqrt{k}$).

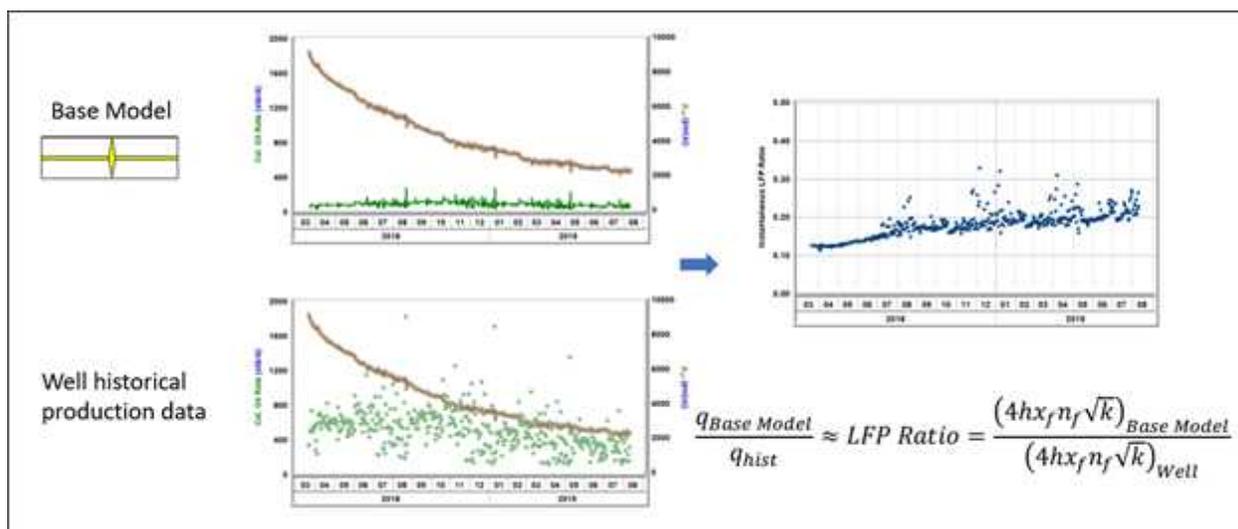
This can be visualized as two models where just the number of fracture stages n_f is different (but the same would apply if h , x_f , or k are different).

In this case, rates produced by these two models are proportional to their LFP ratio:



Now we use this concept to analyze actual well data. We build any model to use as model 1 (as long as it has SRV geometry and stays in linear flow); this model will have the same PVT properties, relative permeabilities, initial pressure, and saturations as the well being analyzed. We call this model the Base Model. LFP for the Base Model is known. The Base Model is calculated with pressure control to obtain $q_{\text{Base Model}}$ rates.

Instead of model 2, we use the actual historical production data of the well:



The LFP ratio can then be estimated from the $\frac{q_{Base Model}}{q_{hist}}$ dataset (plotted against time), and then LFP of the well can be calculated as:

$$4hx_f n_f \sqrt{k} = \frac{(4hx_f n_f \sqrt{k})_{Base Model}}{LFP Ratio}$$

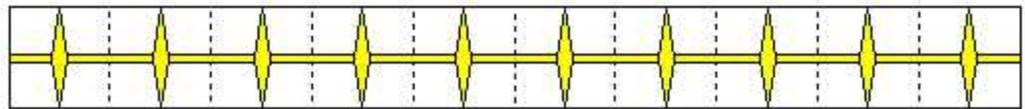
The LFP of the well is the main output from Numerical URM analysis.

Additional outputs, options, and calculations are described in detail in the subsequent sections.

Assumptions

The analysis are done on a production dataset (rates and flowing pressures) for a horizontal multi-frac well. It is assumed that the dataset being analyzed can be modeled closely using a numerical model. This model is referred to as the history-matched model (HM model). It is assumed that the following is true about this model:

- Model geometry is supposed to be an SRV geometry; therefore a linear flow regime is expected for the well followed by boundary-dominated flow.



- Initial reservoir pressure, PVT properties, and relative permeabilities are assumed to be known (should be entered in the Properties editor).
- Geological parameters such as porosity, net pay, saturations, rock compressibility, and pressure-dependent permeability are assumed to be known (should be entered in the Properties editor).
- Other model parameters such as LFP ($A_c \sqrt{k}$), k_{SRV} , t_{elf} , x_f , and $OFIP_{SRV}$ are unknown and can be estimated using the numerical URM analysis.

Essentially, the numerical URM analysis assumes that well behavior can be closely described by the HM model, and gives parameters of this HM model as output.

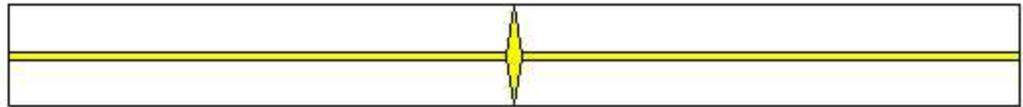
Estimating the LFP

To estimate the linear flow parameter (LFP) of the HM model:

1. In the background, a base linear model (BL model) is created. It is a numerical model that has the same PVT properties, relative permeabilities, and geological properties

as the HM model. The geometry of this base model should represent an SRV model with:

- A known p_i , PVT, and geological properties
- Only one fracture
- High fracture conductivity
- No outside flow ($2x_f =$ reservoir width)
- Single permeability ($k_{SRV} = k_{matrix}$)
- Large lateral length (L_e) so that the base model remains in linear transient flow for the entire simulation



2. Run the BL model at pressure control using the actual drawdown of the well being analyzed.

Equation 1: Pressure drawdown for each timestep is proportional to rate

$$p_i - p_{wf}(t) = F(t) * q_{BL}(t)$$

where $q_{BL}(t)$ are synthesized rates using the BL model (run at pressure control).

During the first transient linear flow, you can think of the HM model as of multiple stages of the BL model. Therefore, if the HM model is also simulated at pressure control, the HM model produces rates that are proportionally higher than the BL model's rates. (The proportion of the rates is defined by the LFP ratio of both models.)

Equation 2

$$LFP \text{ Ratio} = \frac{(4hx_f n_f \sqrt{k})_{BL}}{(4hx_f n_f \sqrt{k})_{HM}}$$

where $(4hx_f n_f \sqrt{k})_{BL}$ is the LFP of the BL model and $(4hx_f n_f \sqrt{k})_{HM}$ is the LFP of the HM model.

The LFP ratio describes the performance ratio of the BL and HM models during transient linear flow.

Equation 3: During transient linear flow

$$\frac{q_{BL}(t)}{q_{HM}(t)} = LFP \text{ Ratio}$$

where $q_{HM}(t)$ are synthesized rates using the HM model (run at pressure control).

During the first transient linear flow, pressure drawdown for the HM model at each timestep can be obtained by combining equations 1 and 3.

Equation 4

$$p_i - p_{wf}(t) = F(t) * q_{HM}(t) * LFP \text{ Ratio}$$

Assuming the HM model describes the production history closely enough,

Equation 5

$$q_{HM}(t) \approx q_{hist}(t)$$

during transient linear flow, combining equations 3 and 5:

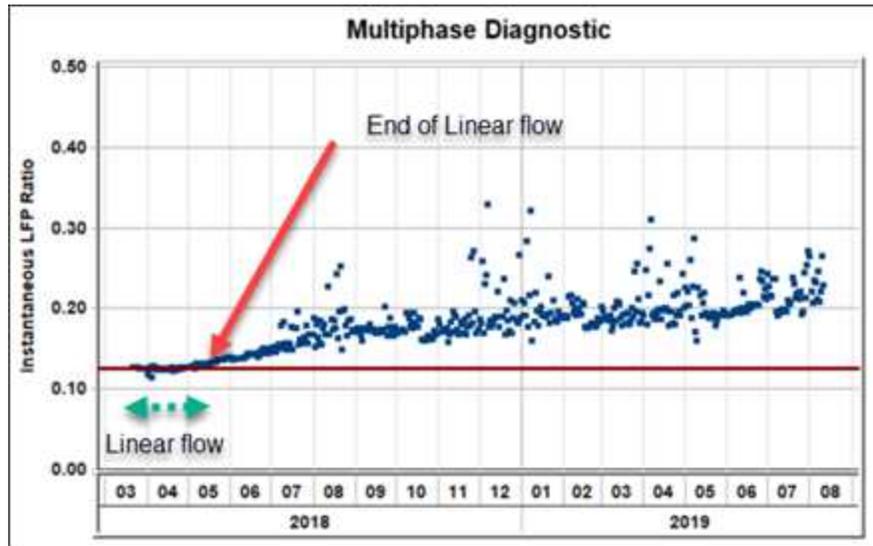
Equation 6

$$LFP \text{ Ratio} \approx \frac{q_{BL}(t)}{q_{hist}(t)}$$

where $q_{hist}(t)$ are historical rates observed by the well.

Equation 6 is used to build the Multiphase Diagnostic plot where $\frac{q_{BL}(t)}{q_{hist}(t)}$ is plotted against time.

These points are supposed to approximately follow a flat trend during the first transient linear flow regime. The position of the flat line (Y-intercept) gives the value of the LFP ratio.



Since all parameters of the BL model are known, $(4hx_f n_f \sqrt{k})_{BL}$ is also known, therefore the LFP of the HM model can be calculated using equations 2.

Equation 7: Main outcome of the numerical URM analysis

$$(A_c \sqrt{k})_{HM} = (4hx_f n_f \sqrt{k})_{HM} = \frac{(4hx_f n_f \sqrt{k})_{BL}}{LFP \text{ Ratio}}$$

Additionally, the same plot can be used to estimate the time to the end of linear flow (t_{elf}). The BL model stays in a transient linear flow regime throughout the entire production history, while the actual well may transition to boundary-dominated flow at some point.

At this time, $\frac{q_{BL}(t)}{q_{hist}(t)}$ starts to increase. Therefore, the time when points on the Multiphase Diagnostic plot start curving upward from the flat trend indicates the end of the first transient linear flow.

Parameter breakdown

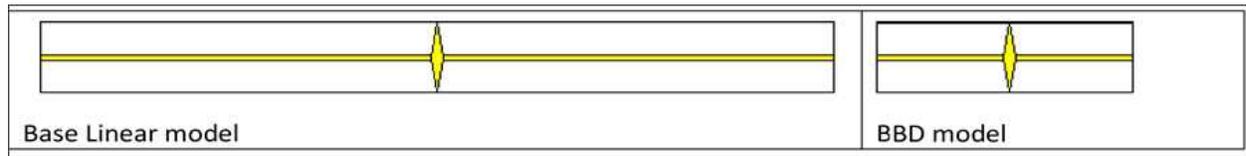
Similar to the traditional URM, the numerical URM analysis does not immediately give values for individual completion parameters. Instead, the combined parameter of $A_c \sqrt{k} = 4hx_f n_f \sqrt{k}$ is estimated. Individual parameters can be calculated assuming that other parameters are known. LFP can be broken down into completion parameters using one of the following two ways:

- k is calculated by entering n_f and x_f , using h from the Properties editor, and $A_c \sqrt{k}$

- x_f is calculated by entering n_f and k , using h from the Properties editor and $A_c \sqrt{k}$

Estimating OFIP

While the BL model stays in transient linear flow throughout the entire production history, the actual well may reach boundary-dominated flow. After this happens, points on the top-left plot start curving upwards. The HM model is assumed to match both the transient linear and the boundary-dominated portion of data. To analyze the boundary-dominated portion of data, additional adjusted base model data is built and run in the background. The adjusted base model is the same as the BL model except it uses a smaller L_e such that the model reaches boundary-dominated flow during simulation time. The adjusted model is referred to as the base boundary-dominated model (BBD model).



The size of the BBD model should be such that transition from the transient linear flow to the boundary-dominated flow happens at the same time as it happens for the HM model. This is achieved by trial and error on $OFIP_{SRV}$ and ultimately L_e of the BBD model.

Equation 8

$$\frac{q_{BBD}(t)}{q_{HM}(t)} = LFP \text{ Ratio}$$

Note that this relationship is true not just during the transient linear flow, but throughout the entire production history.

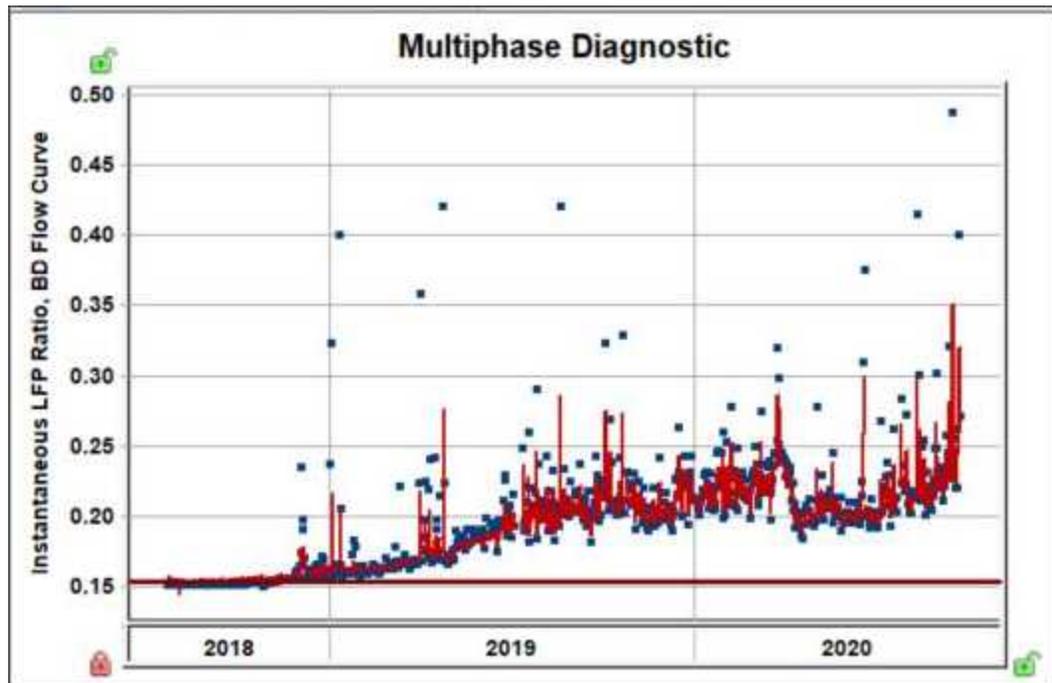
Assuming that the HM model describes the production history closely enough, $q_{HM}(t) \approx q_{hist}(t)$, therefore:

Equation 9

$$\frac{q_{BL}(t)}{q_{hist}(t)} \approx \frac{q_{BL}(t)}{q_{HM}(t)} = \frac{q_{BL}(t)}{q_{BBD}(t)} * LFP \text{ Ratio}$$

To add results from the HM model on the Multiphase Diagnostic plot, the BBD model is run at

pressure control and $q_{BBD}(t)$ is calculated for each timestep; then $\frac{q_{BL}(t)}{q_{BBD}(t)} * LFP Ratio$ is plotted (red curve).



History matching the boundary-dominated portion of the data is done by adjusting the BBD model until:

- Both the BBD model and historical data have the same t_{elf} (red line and data points start curving upwards at the same time).
- The HM model matches the boundary-dominated portion of the data (there is a match between the red line and the points on the top-left plot).

After the match is achieved, $(OFIP)_{BBD}$ can be used to calculate $(OFIP)_{HM}$ using this relationship:

Equation 10

$$\frac{OFIP_{BBD}}{OFIP_{HM}} = LFP Ratio$$

Note: History matching the boundary-dominated portion of the data is done by trial and error. For each $OFIP_{SRV}$, Harmony Enterprise first calculates $OFIP_{BBD}$ using equa-

tion 10, and then calculates L_e for the BBD model. The $q_{BBD}(t)$ is calculated by synthesizing the BBD model and the HM model results are updated using equation 9.

After the boundary-dominated portion of the data is matched, if the match seems reasonably unique, the $OFIP_{SRV}$ can be used to calculate individual completion parameters (x_f and k_{SRV}). Harmony Enterprise calculates x_f based on $OFIP_{SRV}$ and L_e . Then, permeability is calculated based on this x_f and LFP.

History match plot

After both the liner and boundary-dominated portions of data are matched, equation 8 can be rearranged to solve for $q_{HM}(t)$:

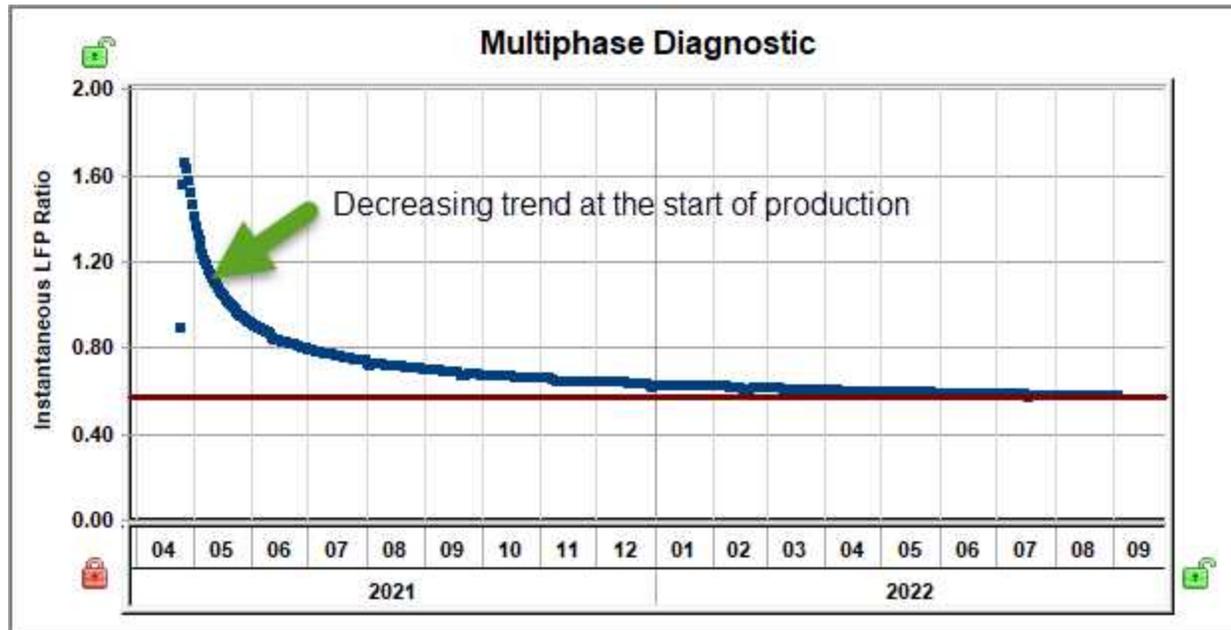
Equation 11

$$q_{HM}(t) = \frac{q_{BBD}(t)}{LFP \text{ Ratio}}$$

$q_{HM}(t)$ and $q_{hist}(t)$ are plotted together against time in the lower-left plot.

Accounting for additional pressure drop (low F_{CD})

Sometimes wells exhibit additional pressure drop. This additional pressure drop may be due to damage around the fracture, low fracture conductivity (F_{CD}), cleanup, or other reasons. In the Multiphase Diagnostic plot, this pressure drop indicates a decreasing portion of the data at the start of production.



If this additional pressure drop behaves as a pressure drop due to skin (that is, it is proportional to the primary rate), it can be accounted for.

If we define a damage factor for the well as ΔP_s , additional pressure drop due to skin at each time can be expressed as $\Delta P_s * q_{hist}(t)$. Therefore, equation 4 can be modified as:

Equation 4a

$$p_i - p_{wf}(t) = F(t) * q_{HM}(t) * LFP\ Ratio + \Delta P_s * q_{HM}(t) \approx \\ \approx F(t) * q_{hist}(t) * LFP\ Ratio + \Delta P_s * q_{hist}(t)$$

Combining equations 1 and 4a and using $q_{HM}(t) \approx q_{hist}(t)$, the LFP ratio can be expressed as:

Equation 6a

$$LFP\ Ratio \approx Instantaneous\ LFP\ Ratio = \\ = \frac{q_{BL}(t)}{q_{hist}(t)} - \Delta P_s \frac{q_{BL}(t)}{p_i - p_{wf}(t)}$$

This can be rearranged as:

Equation 12

$$\underbrace{\frac{q_{BL}(t)}{q_{hist}(t)}}_y \approx \Delta P_s \underbrace{\frac{q_{BL}(t)}{p_i - p_{wf}(t)}}_x + LFP \text{ Ratio}$$

Equation 12 is used to build the Effect of Skin plot:

$$\frac{q_{BL}(t)}{p_i - p_{wf}(t)} \text{ on X-axis and } \frac{q_{BL}(t)}{q_{hist}(t)} \text{ on Y-axis}$$

The portion of the data corresponding to early flow follows a straight line with the slope of ΔP_s and the intercept of the LFP ratio.

The Multiphase Diagnostic plot should also be modified following equation 6a by plotting

$$\frac{q_{BL}(t)}{q_{hist}(t)} - \Delta P_s \frac{q_{BL}(t)}{p_i - p_{wf}(t)} \text{ against time.}$$

During the first linear flow, these points are supposed to approximately follow a flat line. The position of the line gives the value of the LFP ratio.

Equation 6a can be modified for boundary-dominated flow assuming $q_{HM}(t) \approx q_{hist}(t)$:

Equation 13

$$LFP \text{ Ratio} \approx \frac{q_{BBD}(t)}{q_{HM}(t)} - \Delta P_s \frac{q_{BBD}(t)}{p_i - p_{wf}(t)}$$

Equation 13 can be rearranged and solved for $q_{HM}(t)$:

Equation 11a

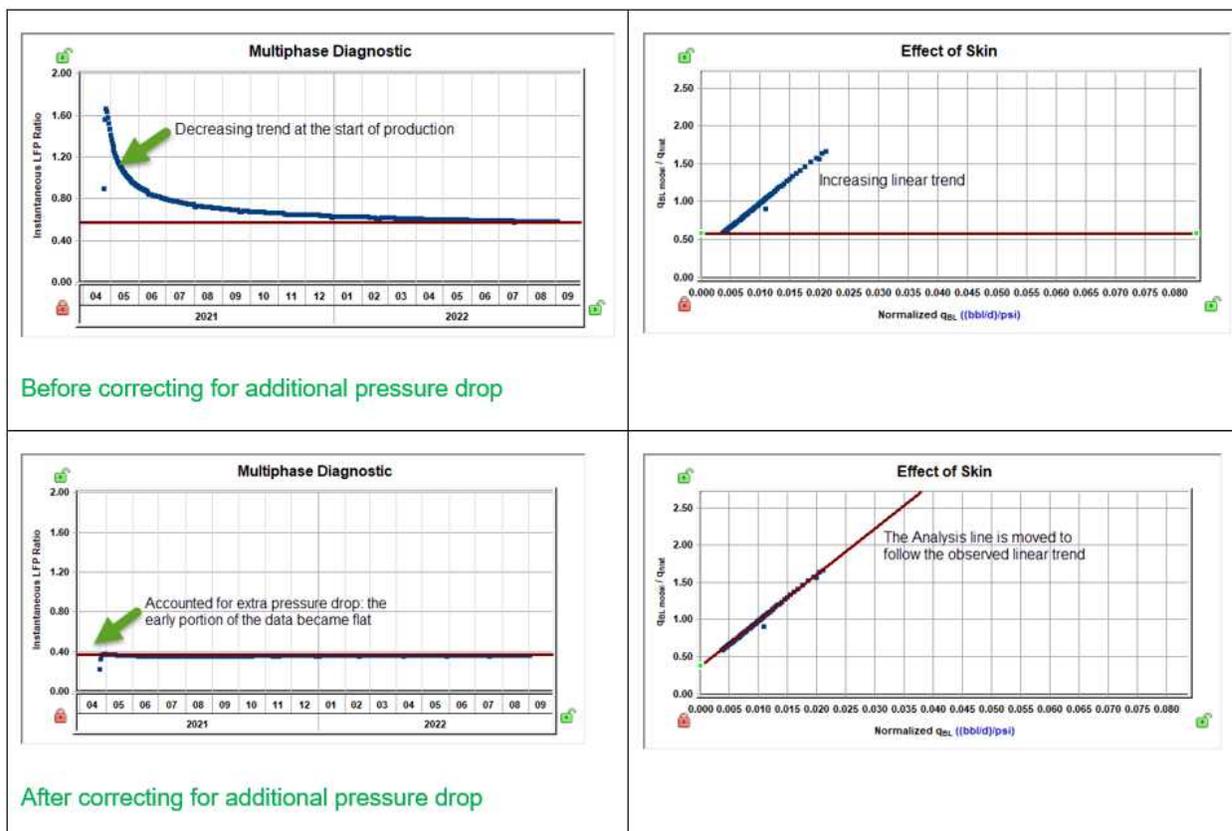
$$q_{HM}(t) = \frac{q_{BBD}(t)}{LFP \text{ Ratio} + \Delta P_s * q_{BBD}(t)/(p_i - p_{wf}(t))}$$

Equation 11a is used to calculate the rate for the HM model (History plot).

Note that the above derivation is all done under the assumption that the additional pressure drop is proportional to the primary rate. In reality this may not always be the case, so you should use this correction with caution. We recommend using this correction only if you see:

- a decreasing slope at the start of production on the Multiphase Diagnostic plot, and

- a clear increasing linear trend on the Effect of Skin plot, and
- a decreasing slope at the start becomes more flat after the correction is applied



Probabilistic theory

In the presence of uncertainty re: input data required for determining the best estimate of a value, probabilistic methods are used. For example, there may be uncertainty in net pay or drainage area while estimating OGIP using volumetric calculations.

Probabilistic analysis is a technique to quantify the impact of these uncertainties on output variables, and to determine a range of possible outcomes, as opposed to a single deterministic solution. The uncertainty in the output also provides a measure of the validity of the model.

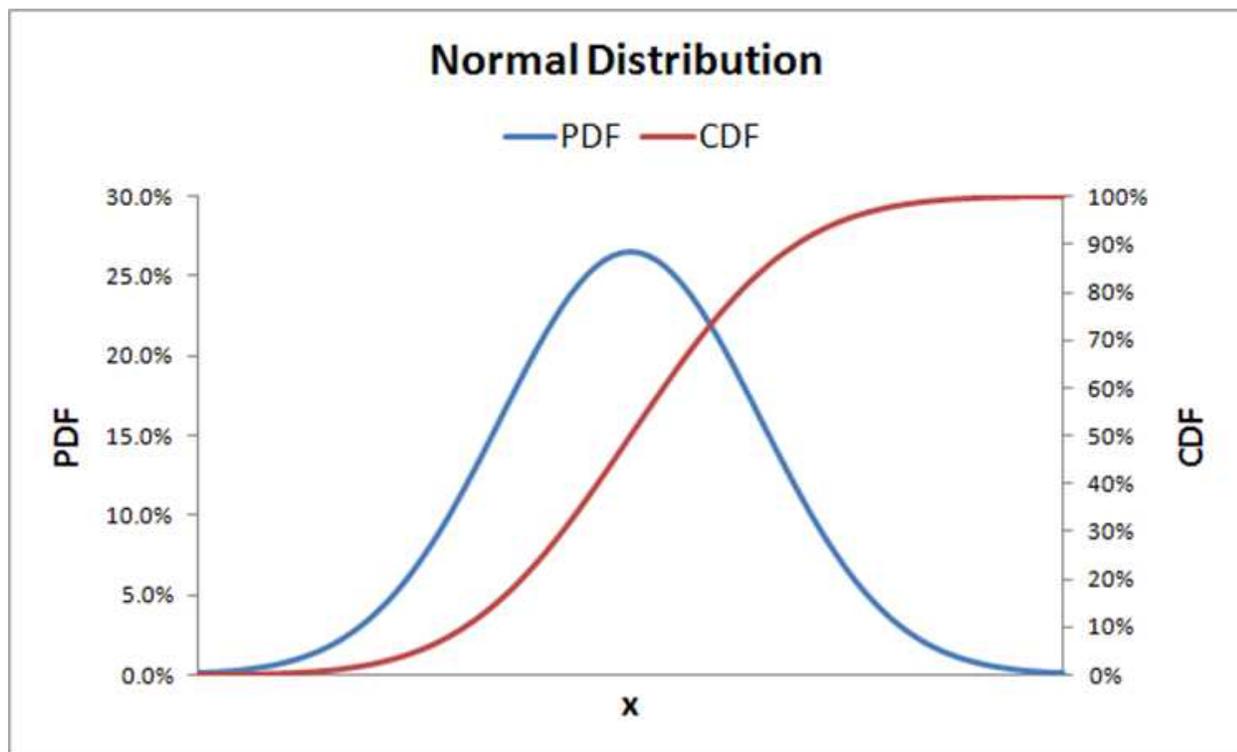
The Monte Carlo simulation (using Latin hypercube sampling) is an established approach of performing a probabilistic analysis. The Monte Carlo analysis involves a large number of runs, each of which is a deterministic calculation. The inputs to these deterministic calculations are randomly drawn from probability density functions (PDFs) that describe the likely values of an input

parameter. The more realistic these PDFs are, the more realistic the estimate of the output parameter, as calculated by the Monte Carlo simulation.

Probability distribution types

In this section, we define the different probability distribution types used as part of the probabilistic analysis. The definitions include the equations for the PDF, cumulative distribution function (CDF), mean, median, and mode for each of the probability distribution types.

Normal distribution



$$\text{PDF: } f(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{(x-\mu)^2}{2\sigma^2}}$$

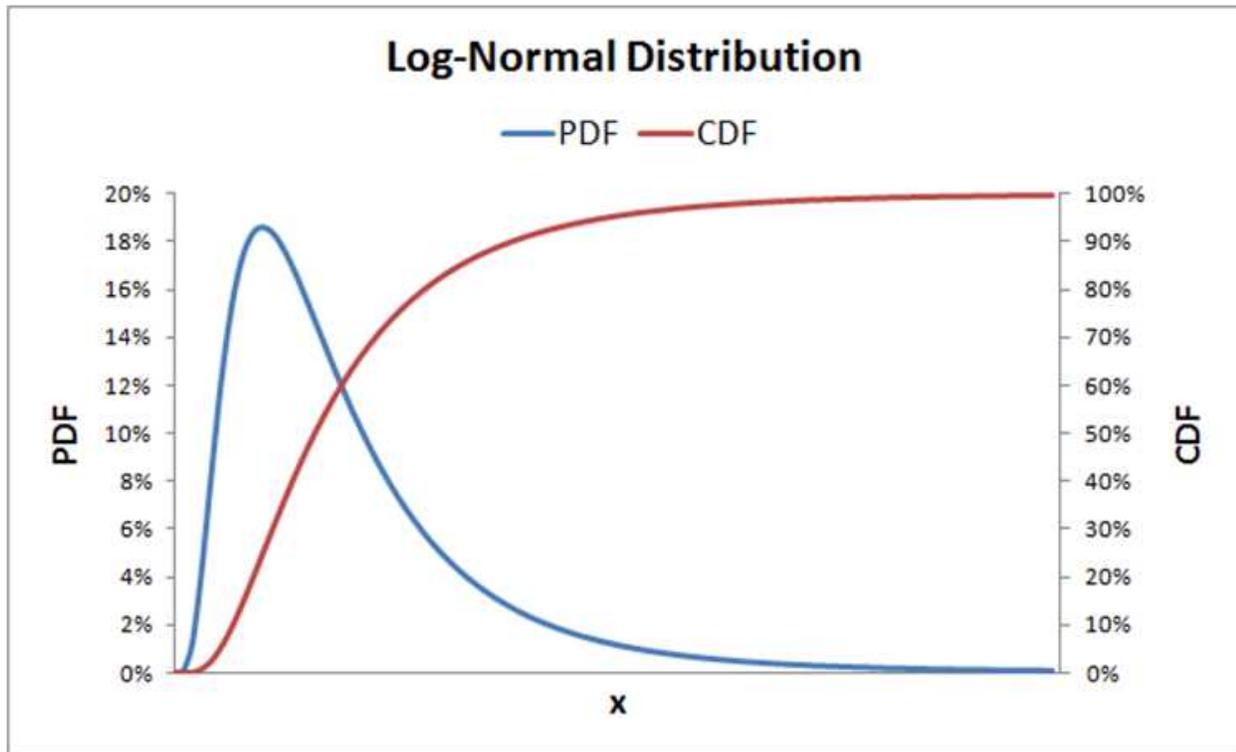
$$\text{CDF: } F(x) = \frac{1}{2} \left[1 + \text{erf} \left(\frac{x-\mu}{\sigma\sqrt{2}} \right) \right]$$

$$\text{Mean} = \text{Median} = \text{Mode} = \mu = \bar{x} = \frac{1}{n} \sum_{i=1}^n x_i$$

$$\text{Variance} = \sigma^2 = s^2 = \frac{1}{n-1} \sum_{i=1}^n (x_i - \bar{x})^2$$

Note: The variance calculation uses the Bessel correction for bias.

Log-normal distribution



$$\text{PDF: } f(x) = \frac{1}{x\sigma\sqrt{2\pi}} e^{-(\ln(x)-\mu)^2/(2\sigma^2)}$$

$$\text{CDF: } F(x) = \frac{1}{2} + \frac{1}{2} \left[1 + \operatorname{erf} \left(\frac{\ln(x) - \mu}{\sigma\sqrt{2}} \right) \right]$$

$$\text{Mean} = e^{\mu + \sigma^2/2}$$

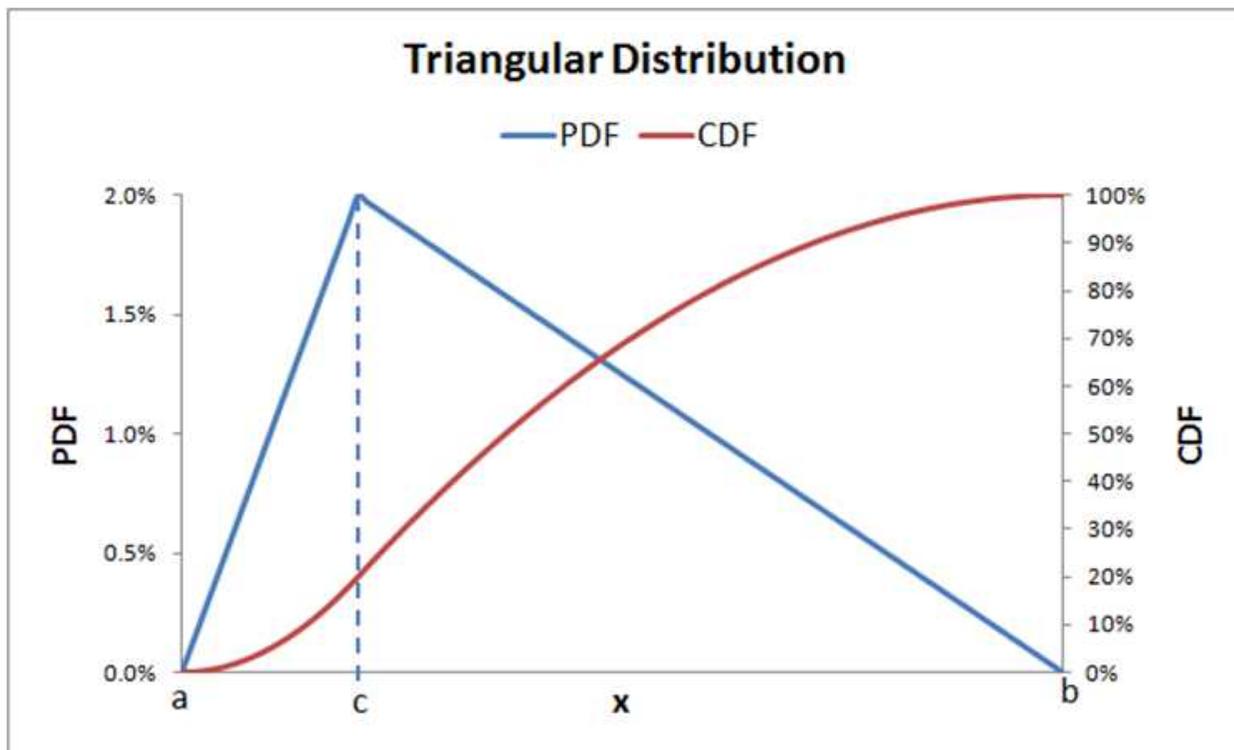
$$\text{Mode} = e^{\mu - \sigma^2}$$

$$\text{Median} = e^{\mu}$$

$$\text{Variance} = (e^{\sigma^2} - 1)e^{\sigma^2 + 2\mu}$$

A log-normal distribution is the probability distribution of a random variable whose natural logarithm follows a normal distribution. The log of a set of data that follows a log-normal distribution follows a normal distribution. As such, it should be noted that μ is the mean of the natural log of the dataset, and σ is the standard deviation of the natural log of the dataset (that is, the mean and standard deviation of the underlying normal distribution).

Triangular distribution



$$\text{PDF: } f(x) = \begin{cases} 0 & x < a \\ \frac{2(x-a)}{(b-a)(c-a)} & a \leq x \leq c \\ \frac{2(b-x)}{(b-a)(b-c)} & c < x \leq b \\ 0 & b < x \end{cases}$$

$$\text{CDF: } F(x) = \begin{cases} 0 & x < a \\ \frac{(x-a)^2}{(b-a)(c-a)} & a \leq x \leq c \\ 1 - \frac{(b-x)^2}{(b-a)(b-c)} & c < x \leq b \\ 1 & b < x \end{cases}$$

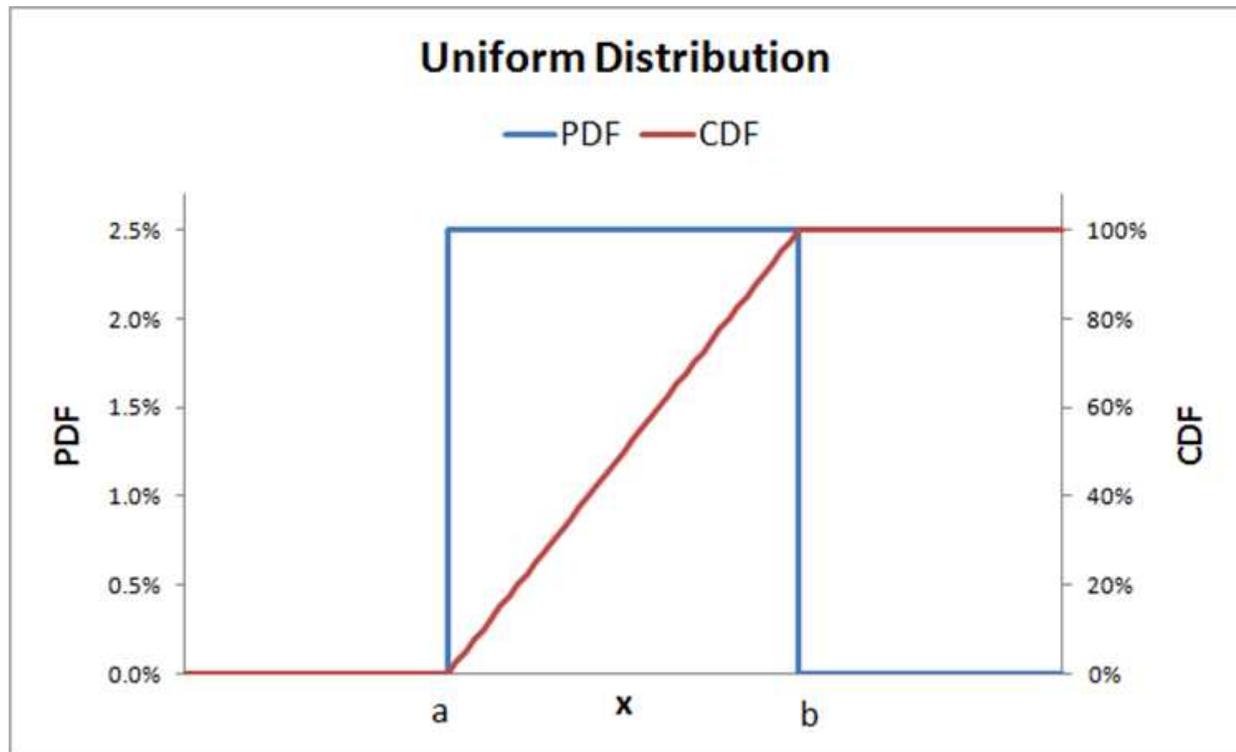
$$\text{Mean} = \frac{1}{3}(a + b + c)$$

$$\text{Median} = \begin{cases} a + \frac{\sqrt{(b-a)(c-a)}}{\sqrt{2}} & c \geq \frac{a+b}{2} \\ b - \frac{\sqrt{(b-a)(b-c)}}{\sqrt{2}} & c \leq \frac{a+b}{2} \end{cases}$$

$$\text{Mode} = c$$

$$\text{Variance} = \frac{a^2 + b^2 + c^2 - ab - ac - bc}{18}$$

Uniform distribution



$$\text{PDF: } f(x) = \begin{cases} \frac{1}{b-a} & a \leq x \leq b \\ 0 & \text{otherwise} \end{cases}$$

$$\text{CDF: } F(x) = \begin{cases} 0 & x \leq a \\ \frac{x-a}{b-a} & a < x < b \\ 1 & x \geq b \end{cases}$$

$$\text{Mean} = \text{Median} = \frac{1}{2}(a + b)$$

Mode = any value in $a \leq x \leq b$

$$\text{Variance} = \frac{1}{12}(b - a)^2$$

Calculation methods

Calculation methods are described below.

Monte Carlo simulation

The Monte Carlo simulation is a stochastic modeling method to simulate real-world situations where there is uncertainty in the input variables. This uncertainty cannot be directly modeled using analytical solutions. While conceptually very simple, a trivial example provides the easiest route to developing an understanding of the Monte Carlo simulation procedure.

Consider the simple estimation of prospect reserves (*EUR*, stbo) calculated as the product of the prospect area (*A*, acres), average net hydrocarbon thickness (*h*, feet), and recovery factor (*RF*, stbo/acre-ft). The algebraic expression of this simple model is:

$$EUR = A \times h \times RF$$

The deterministic approach would simply multiply the "best estimate" for each of these quantities to obtain a single value of *EUR*. The deterministic approach assumes that the most likely value of every input is encountered simultaneously, which is generally very unrealistic.

Suppose that for each of the three input variables, *A*, *h*, and *RF*, independent cumulative probability distributions can somehow be defined, thereby describing the uncertainty in each of these variables. The Monte Carlo method can make use of these distributions to arrive at an overall cumulative probability distribution (overall uncertainty) for *EUR*. This analysis approach is superior to the single-valued deterministic approach because of the valuable insight gained into the "upside," "downside," "most likely outcome," and the "mean" level of reserves that would result from drilling a large number of similar prospects.

The following describes one pass in the Monte Carlo simulation procedure:

1. Generate a random number between zero and one (representing the value of the cumulative probability) for each of the three input variables.
2. Enter the cumulative probability distribution for each input variable at their respective random number to determine the "sampled" value for each input.
3. Multiply the three independent variable sampled values to yield a sample reserve estimate.

An individual calculation or run to estimate a prospect size in this fashion is known as a "pass". By itself, the individual value of *EUR* generated by a pass is meaningless. However, when repeated a large number of times, a cumulative distribution for the *EUR* emerges.

The minimum number of passes required depends on the number of input variables that are risked. Generally, enough runs are needed to ensure that the entire domain of input variables is examined. The larger the number of input variables, the larger the minimum number of passes required.

Typically, 1000 or more passes comprise a single Monte Carlo simulation. As a qualitative rule, a smooth CDF of output variables is an indication of an appropriate number of runs.

After a Monte Carlo simulation run is finished, an analysis of the results follows. Assuming a 1,000 pass simulation run, results are processed as follows:

1. Arrange EUR results in ascending order.
2. Number the sorted EUR values from 1 to the total number of samples (for example, 1,000).
3. Calculate the cumulative probability of each value by dividing the sample number by the total number of samples (in this case, 1000).
4. Plot the resultant cumulative probability function (Cumulative Probability vs. EUR) to ascertain the smoothness of the distribution. Lacking a smooth distribution necessitates re-running the simulation with a larger number of passes.
5. Calculate the mean, variance, P10, P50, P90, and any other desired statistical parameters.

This analysis yields the statistical parameters desired for the prospect analysis. Expect the values of these parameters to vary slightly with each simulation. An unacceptably large variation warrants an increase in the number of passes.

Latin hypercube sampling

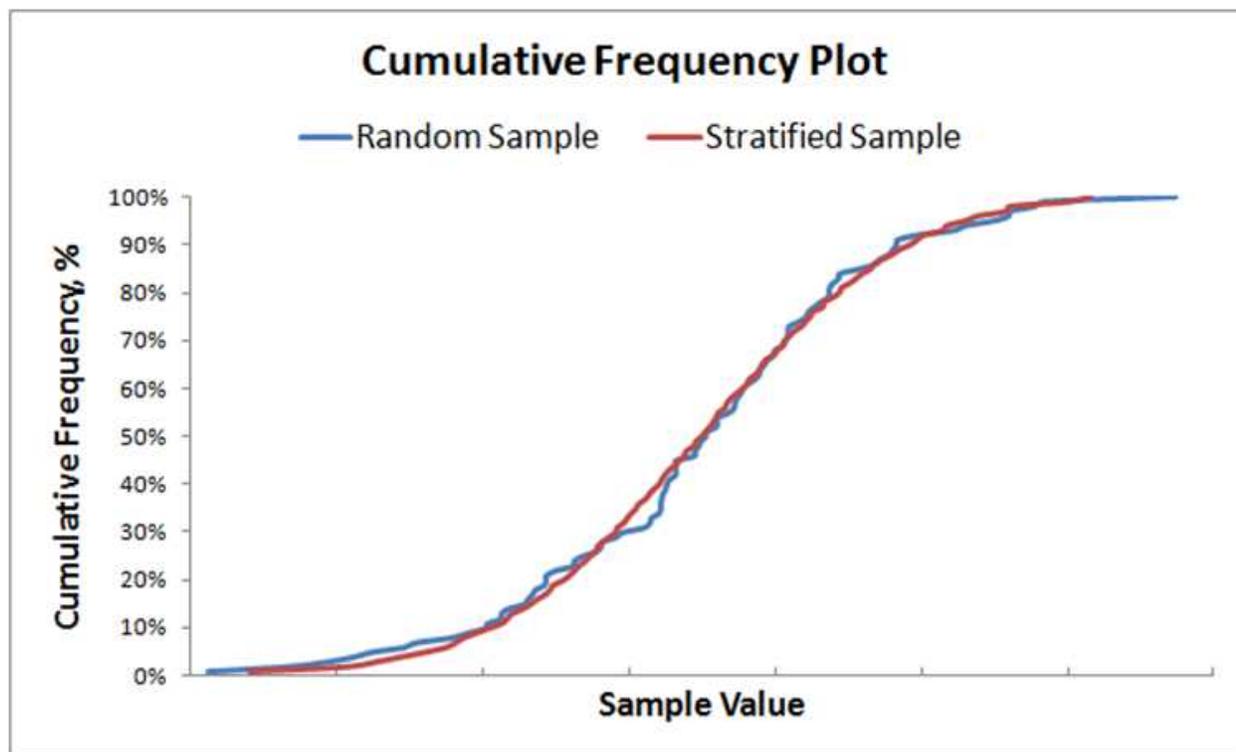
Selecting random values for model parameters can require a large number of simulation passes to generate a smooth cumulative probability distribution. Latin hypercube sampling, also known as stratified sampling, is a process applied to multiple variables to reduce the required number of passes in a Monte Carlo simulation.

First, stratified sampling is used to force randomly generated numbers to conform to the CDF represented by their statistical distribution. Normally, you could generate a random number between zero and one representing the cumulative probability a number of times, and use those numbers to read the CDF. Instead, the span of zero to one is split between the number of samples to be taken, and points within those smaller spans are randomly selected. Each of the samples is generated by:

$$\frac{n-1}{N} + \frac{r}{N}$$

where n is the interval index, N is the number of non-overlapping intervals, and r is a randomly generated number between zero and one (newly generated for each sample).

The effects of stratified sampling can be dramatic. The figure below compares the Cumulative Frequency Plot of 100 random samples with 100 stratified samples.

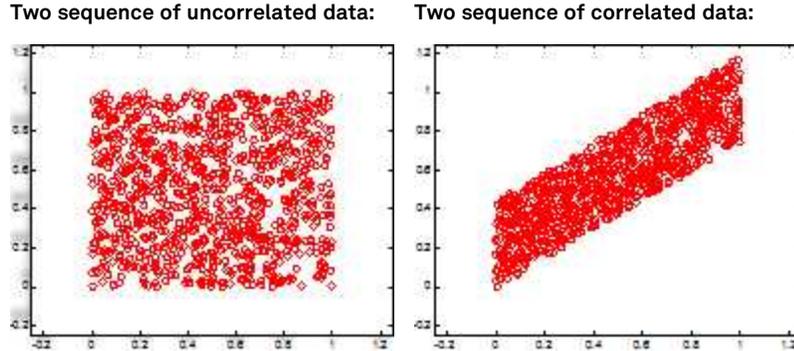


After the stratified sampling is performed on all variables, the samples are randomly grouped together to generate the parameters to be entered into the model for each simulation pass. Each value must only be used once.

Correlated sampling

This section describes methods for generating multiple sequences of correlated random variables. In other words, the values sampled in one distribution are correlated to the values sampled in another distribution, given the correlation coefficients between the two samples.

These screenshots show examples of two sequences of uncorrelated and correlated random data.



Creation of correlated random variables

The rank-order correlation approach of Spearman as presented by Iman and Conover (Iman & Conover, 1982) is used to create a set of multi-variable correlated random variables.

This approach is based on using rank correlations to define dependencies among input variables. By ranking the values and using them as opposed to the actual values, the Spearman rank correlation of the input values are kept as close as possible to the target rank correlation coefficient matrix, as specified.

Because this approach is distribution-free:

- it preserves the exact form of the probability distribution functions
- it may be used with any type of distribution function

Auto-correction to user-input correlation coefficient matrix

To generate a sequence of multi-variable correlated random numbers, we need to specify the applicable matrix of correlation coefficients. This matrix is required to be positive and definite (that is, all the eigenvalues of this matrix are to be greater than zero).

If the user-specified matrix of correlation coefficients fails to qualify as a positive-definite matrix, “The Method of Eigenvalues” is used to auto-correct the matrix. Through application of slight perturbation to negative or zero eigenvalues, this method attempts to repair the correlation coefficient matrix, and make it a positive-definite one, while introducing the smallest possible changes to the matrix.

Truncated distributions

Truncated distributions are described below.

Definitions and concept

A truncated distribution is a conditional distribution that results from restricting the domain of some other distribution. In practical statistics, a truncated distribution arises from situations where the ability to record, or even know about, occurrences is limited to values which lie above or below a given threshold, or specific range.

Assuming that a random variable x has a probability density function of $f(x)$ and a cumulative distribution function of $F(x)$, which both have infinite support ($-\infty < x < \infty$), then the probability density function after truncating the support to $a < x \leq b$ can be expressed as:

$$f(x|a < x \leq b) = \frac{g(x)}{F(b) - F(a)} = Tr(x)$$

where:

$$g(x) = \begin{cases} f(x) & a < x \leq b \\ 0 & \text{everywhere else} \end{cases}$$

Note that $Tr(x)$ itself is a distribution such that:

$$F(x|a < x \leq b) = \frac{1}{F(b) - F(a)} \int_a^b g(x) d(x) = 1$$

In general, the PDF of a truncated distribution function can be calculated as:

$$TrPDF(x) = \frac{g(x)}{F(b) - F(a)} \quad a < x \leq b$$

$$TrPDF(x) = \frac{g(x)}{1 - F(a)} \quad a < x$$

$$TrPDF(x) = \frac{g(x)}{F(b)} \quad x \leq b$$

The CDF of a truncated distribution function can be calculated as:

$$TrCDF(x) = \frac{\int_a^x g(x)dx}{F(b) - F(a)} \quad a < x \leq b$$

$$TrCDF(x) = \frac{\int_a^x g(x)dx}{1 - F(a)} \quad a < x$$

$$TrCDF(x) = \frac{\int_{-\infty}^x g(x)dx}{F(b)} \quad x \leq b$$

The mean of the truncated distributions are calculated as:

$$\text{mean}(x) = \frac{\int_a^x xg(x)dx}{F(b) - F(a)} \quad a < x \leq b$$

$$\text{mean}(x) = \frac{\int_a^x xg(x)dx}{1 - F(a)} \quad a < x$$

$$\text{mean}(x) = \frac{\int_{-\infty}^x xg(x)dx}{F(b)} \quad x \leq b$$

Special case: truncated normal distributions

Defining:

$$\phi(x) = \frac{1}{\sqrt{2\pi}} e^{-\frac{1}{2}x^2}$$

$$\Phi(x) = \frac{1}{\sqrt{2}} \left[1 + \text{erf}\left(\frac{x}{\sqrt{2}}\right) \right]$$

The PDF of a truncated normal distribution can be calculated as:

$$TrPDF(x) = \frac{\frac{1}{\sigma} \phi\left(\frac{x-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right) - \Phi\left(\frac{a-\mu}{\sigma}\right)} \quad a \leq x \leq b$$

$$TrPDF(x) = \frac{\frac{1}{\sigma} \phi\left(\frac{x-\mu}{\sigma}\right)}{1 - \Phi\left(\frac{a-\mu}{\sigma}\right)} \quad a \leq x$$

$$TrPDF(x) = \frac{\frac{1}{\sigma} \phi\left(\frac{x-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right)} \quad x \leq b$$

The mean of a truncated normal distribution can be calculated as:

$$\text{mean}(x) = \mu + \frac{\phi\left(\frac{a-\mu}{\sigma}\right) - \phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right) - \Phi\left(\frac{a-\mu}{\sigma}\right)} \sigma \quad a \leq x \leq b$$

$$\text{mean}(x) = \mu + \frac{\phi\left(\frac{a-\mu}{\sigma}\right)}{1 - \Phi\left(\frac{a-\mu}{\sigma}\right)} \sigma \quad a \leq x$$

$$\text{mean}(x) = \mu + \frac{\phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right)} \sigma \quad x \leq b$$

The variance of a truncated normal distribution can be calculated as:

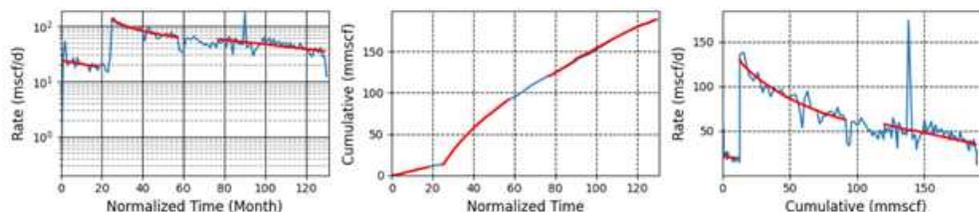
$$\text{variance}(x) = \sigma^2 \left[1 + \frac{\left[\frac{(a-\mu)}{\sigma}\right] \phi\left(\frac{a-\mu}{\sigma}\right) - \left[\frac{(b-\mu)}{\sigma}\right] \phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right) - \Phi\left(\frac{a-\mu}{\sigma}\right)} - \left[\frac{\phi\left(\frac{a-\mu}{\sigma}\right) - \phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right) - \Phi\left(\frac{a-\mu}{\sigma}\right)} \right]^2 \right] \quad a \leq x \leq b$$

$$\text{variance}(x) = \sigma^2 \left[1 + \frac{\left[\frac{(a-\mu)}{\sigma}\right] \phi\left(\frac{a-\mu}{\sigma}\right)}{1 - \Phi\left(\frac{a-\mu}{\sigma}\right)} - \left[\frac{\phi\left(\frac{a-\mu}{\sigma}\right)}{1 - \Phi\left(\frac{a-\mu}{\sigma}\right)} \right]^2 \right] \quad a \leq x$$

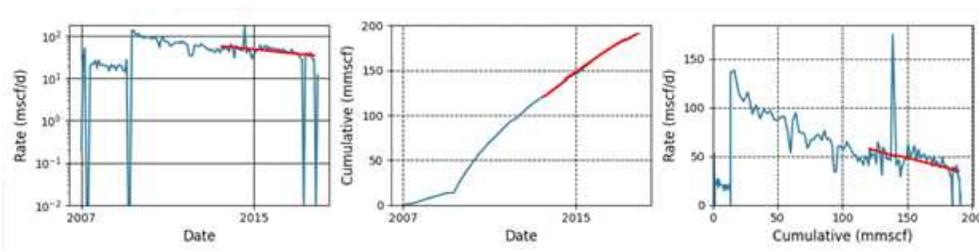
$$\text{variance}(x) = \sigma^2 \left[1 + \frac{\left[\frac{(b-\mu)}{\sigma}\right] \phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right)} - \left[\frac{\phi\left(\frac{b-\mu}{\sigma}\right)}{\Phi\left(\frac{b-\mu}{\sigma}\right)} \right]^2 \right] \quad x \leq b$$

Probabilistic decline method (beta)

The probabilistic forecast (beta) starts with a decline fit, similar to the traditional Arps decline in Harmony Enterprise. Shut-ins and outliers are removed, and the data is divided into partitions of distinct rate trends.



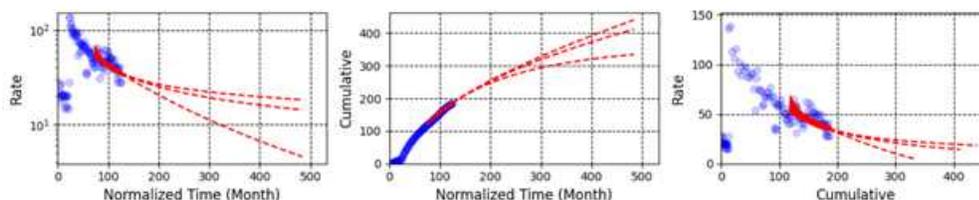
The partition at the end of the production history is fit to determine a decline forecast as a starting point.



The q_i , D_i , and b from this initial fit become the starting point for distributions for additional forecasts. The b is sampled evenly across the range defined by the minimum and maximum specified in the Options dialog box. The q_i is sampled in the range around the best-fit result. However, rather than independently sampling D_i values, the decline equation is used to determine the relationship between inputs, so that D_i can be calculated from each q_i , b pair.

The decline forecast for each of these parameter sets is calculated. The quality of fit is then assessed and only good matches are kept.

This collection of forecasts is then sorted and the percentiles specified in the Options dialog box are calculated. Since a consistent approach is used in determining q_i and b , and the relationship to D_i , the results from this method are reproducible.



Note: Harmony Enterprise uses the reserves evaluation convention for percentiles, which is the inverse of the statistical percentiles traditionally used. For example, a P90 represents the 10th percentile in statistical terms, where 10% of the set is less than this value, and 90% is greater than this value. Harmony Enterprise converts the input percentiles into the correct statistical version for calculation purposes.

Stretched exponential decline theory

One of the benefits of a stretched exponential decline is that for positive n , τ , q_i , the model gives a finite value of EUR, even if no abandonment constraints are used in time or rate.

The Stretched Exponential Production Decline Model		
$\frac{dq}{dt} =$	$-n\left(\frac{t}{\tau}\right)^n \frac{q}{t}$	Defining the differential equation of the model
$q =$	$q_o \exp\left[-\left(\frac{t}{\tau}\right)^n\right]$	Rate expression as a function of time
$Q =$	$\frac{q_o\tau}{n} \left\{ \Gamma\left[\frac{1}{n}\right] - \Gamma\left[\frac{1}{n}, \left(\frac{t}{\tau}\right)^n\right] \right\}$	Cumulative production as a function of time
$EUR =$	$\frac{q_o\tau}{n} \Gamma\left[\frac{1}{n}\right]$	EUR in terms of model parameters
Reference <u>SPE</u> papers: 134231, 143666, 137414, 144311, and 135616.		

Surveillance analysis theory

A well-planned surveillance program is key to understanding reservoir performance and identifying opportunities to improve ultimate recovery. With surveillance analysis, you can perform Hall Plot and voidage replacement ratio (VRR) analyses. The Hall Plot analysis enables you to draw conclusions about average injectivity performance. The VRR analysis aids in identifying parts of a field where more or less water must be injected in order to reach or maintain VRR targets.

Hall plot analysis

The Hall plot analyzes steady-state flow at an injection well. In general, the slope of a Hall plot is interpreted as an indicator of the average well injectivity. At normal conditions, the plot is a straight line. Kinks on the plot indicate changes in injection conditions.

Hall (in 1963) presented this technique to interpret routinely collected injection well data to draw conclusions regarding near wellbore skin effects and average injectivity performance. The data required for the Hall Plot analysis includes the following:

- monthly sandface injection pressures (monthly average)
- average reservoir pressure
- monthly water injection volumes
- injection days for the month

The Hall method assumes steady-state injection such that the injection rate can be expressed as:

Equation 1

$$i_w = \frac{0.00707kh(p_{wi} - p_{avg})}{\mu \left[\ln \frac{r_e}{r_w} + S \right]}$$

where:

k = permeability,

h = reservoir thickness

p_{wi} = flowing wellhead pressure

p_{avg} = average reservoir pressure

μ = fluid viscosity

r_e = reservoir effective radius

r_w = wellbore radius

S = skin

Equation 1 is based on the following assumptions:

- the fluid is homogenous and incompressible
- the reservoir is vertically confined and uniform, both with respect to permeability and thickness
- the reservoir is horizontal and gravity does not affect flow (consequently, the flow is radial)
- the flow is steady-state
- the mobility ratio is equal to 1
- during the time of observation, the pressure at the distance equal to r_e is constant, and this distance itself is constant as well

At this point, it is assumed that k, h, μ , r_e , r_w and S are constant. Therefore, equation 1 reduces to:

Equation 2

$$i_w = C(p_{wi} - p_{avg})$$

where:

Equation 3

$$C = \frac{0.00707kh}{\mu \left[\ln \frac{r_e}{r_w} + S \right]}$$

Rearranging equation 2 yields the following:

Equation 4

$$(p_{wi} - p_{avg}) = \frac{i_w}{C}$$

Integrating both sides of equation 4 with respect to time gives:

Equation 5

$$\int_0^t (p_{wi} - p_{avg}) dt = \frac{1}{C} \int_0^t i_w dt$$

The integral on the right-side of equation 5 is cumulative water injected. Therefore, equation 5 can be represented as:

Equation 6

$$\int_0^t (p_{wi} - p_{avg}) dt = \frac{W_i}{C}$$

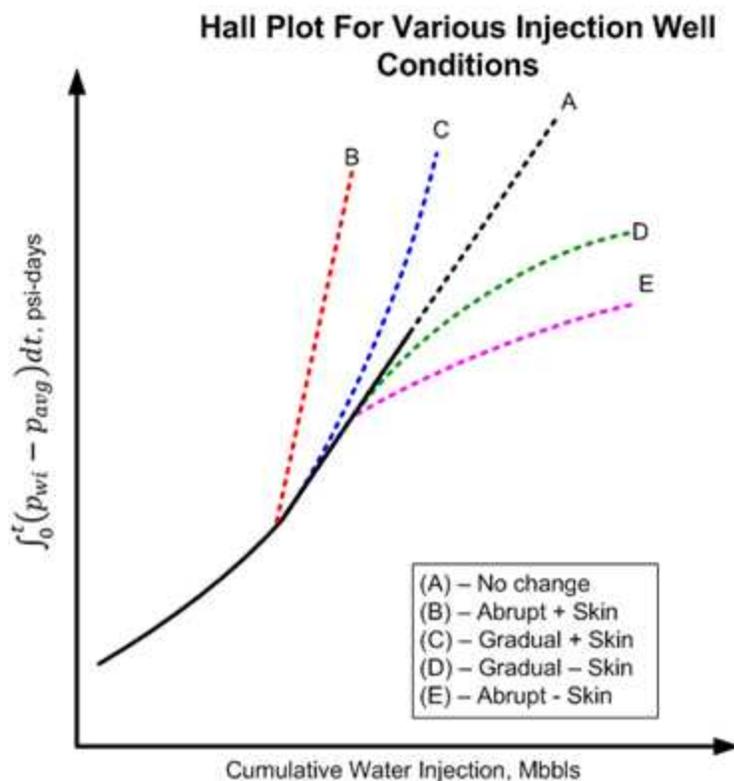
where:

W_i = cumulative volume of water injected at time t, bbls

Closer inspection of equation 6 indicates that a coordinate graph of its left-side versus the right-side should form a straight line with a slope of 1/C. This type of graph is called the Hall Plot. If h, μ , r_e , r_w , and S are constant, then from equation 3, the value of C is constant and the slope is constant. However, if the parameters change, C also changes and thus the slope of the Hall Plot changes, which is where the diagnostic value of the plot is.

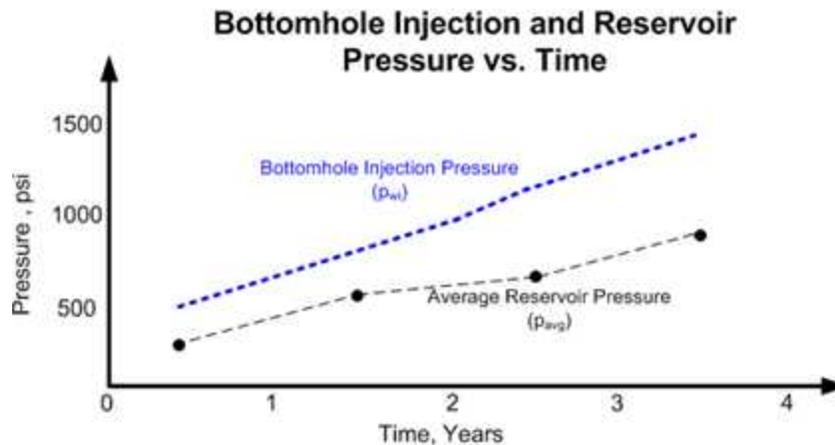
Changes in injection conditions may be noted from the Hall Plot. For example, if wellbore plugging or other restrictions to injection are gradually occurring, the net effect is a gradual increase in the skin factor, S . As S increases, C decreases; thus, the slope of the Hall Plot increases. Conversely, if S decreases (as would be the case if injecting pressure exceeds fracture pressure, causing fracture growth), then C increases and the slope of the Hall Plot decreases. See Figure 1 for various injection well conditions and their Hall Plot signatures.

Figure 1. Hall Plot characteristic signatures



The most challenging part of developing the Hall Plot is calculating the pressure-integral function of the y-axis. Fortunately, the integral can be easily solved. Consider Figure 2, which shows a graph of monthly sandface injection pressure, p_{wi} , and periodic estimates of average reservoir pressure, p_{avg} .

Figure 2. Sandface Injection and Reservoir Pressure vs. Time



If it can be assumed that p_{wi} and p_{avg} are average for the month, then

Equation 7

$$\int_0^t (p_{wi} - p_{avg}) dt = \sum \Delta p * \Delta t$$

where:

$$\Delta p = p_{wi} - p_{avg}$$

Δt = number of injection days for the month

Changes in the slope of the Hall Plot typically occur gradually, so several months (6 or more) of injection history may be needed to reach reliable conclusions about injection behavior, as is the case for production decline curve analysis.

It is important to note that changes in the slope of the Hall Plot can be the result of other factors. Early in the life of an injection well (before gas fill-up), the radius of the water and oil zones increase with cumulative injection and cause the value of C to increase, resulting in a concave upward trend in the Hall Plot. Recall that the Hall Plot technique assumes a mobility ratio of 1.0. If the mobility ratio is greater than 1, then the Hall Plot gradually trends concave downwards after gas fill-up (as shown in curve D in [Figure 1](#)); if the mobility ratio is less than 1.0, it will gradually trend concave upwards (see curve C). Also, as the average water saturation in the reservoir increases with time, k_w may increase, which can also affect the slope of the plot.

If after gas fill-up it can be assumed that p_{avg} does not change significantly, then calculating the y-axis on the Hall Plot is greatly simplified by dropping p_{avg} . This is because if p_{avg} is constant and ignored, the Hall Plot is only shifted on the y-axis without changing the slope or its diagnostic interpretive value. Under this condition, the sandface injection pressure (p_{wi}) is simply the well-head injection pressure plus a hydrostatic gradient minus a frictional loss term. Since these two

terms can usually be assumed to be constant and neglected, the left-side of equation 6 can simply reduce to the integral of the wellhead injection pressure, a dataset that is more readily available.

To determine whether average reservoir pressure is changing, it is necessary to conduct regular pressure buildup / falloff tests and to monitor monthly VRR plots. The objective of the Hall Plot is to detect changes in the injection well skin factor. It is not a perfect tool, but can under certain conditions, provide reasonable insight on skin changes. The best tool for quantifying injection wellbore skin damage is a properly designed, well-executed, and fully analyzed pressure fallout test.

References: Waterflooding Course, William M. Cobb & James T. Smith.

Voidage Replacement Ratio

Voidage replacement refers to replacing the volume of oil, gas, and water produced from the reservoir by injected fluids. The voidage replacement ratio (VRR) is the ratio of reservoir barrels of injected fluid to reservoir barrels of produced fluid. Mathematically (for water and gas injection), VRR can be expressed as follows:

Equation 8

$$VRR = \frac{\text{injected reservoir vols}}{\text{produced resevoir vols}} = \frac{B_w_{inj}I_w_{inj} + B_g_{inj}I_g_{inj}}{B_oQ_o + B_wQ_w + B_g(GOR - R_s)Q_o}$$

where:

B_x = formation volume factor for fluid type x

I_x = injected volume for fluid type x

Q_x = produced volume for fluid type x

GOR = produced gas oil ratio

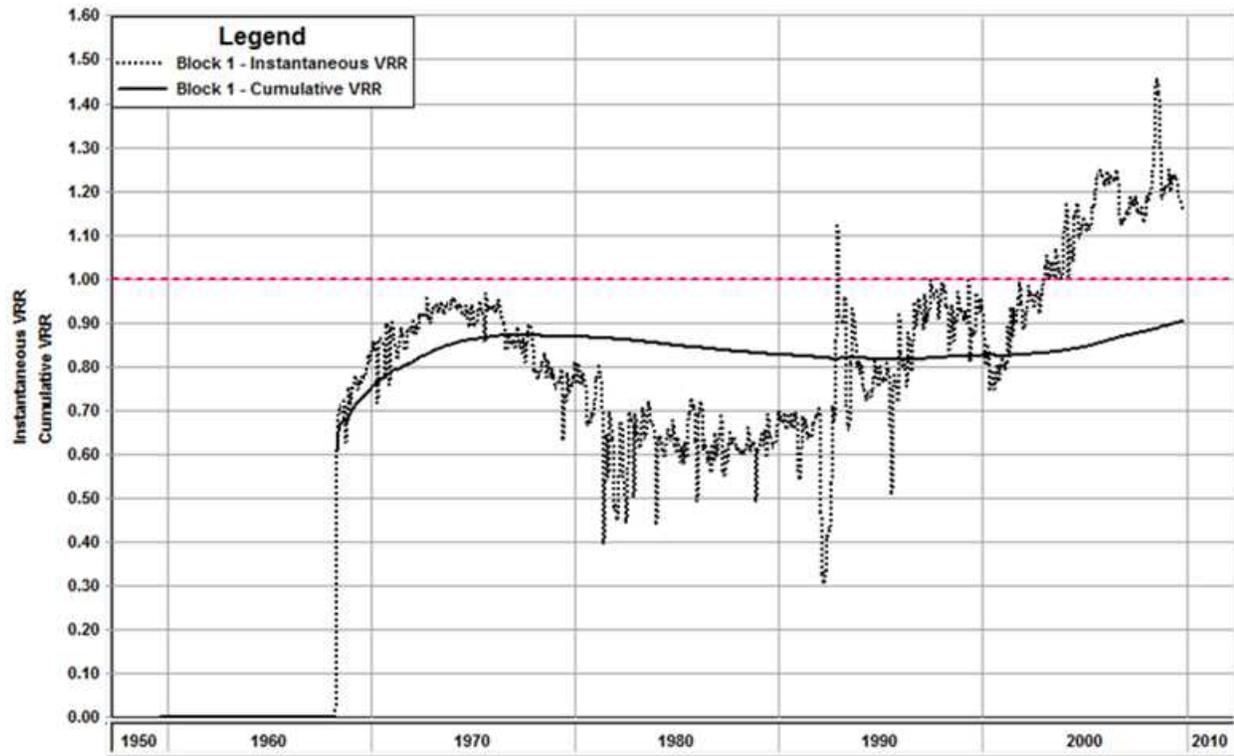
R_s = solution gas oil ratio

In equation 8, the third term in the denominator accounts for free gas produced that is in excess of the gas in the reservoir that is dissolved in the oil.

VRR can be calculated on an instantaneous basis using injected and produced fluids over any specific time period (typically daily or monthly), with GORs calculated from instantaneous volumes. It can also be calculated on a cumulative basis using cumulative injected and produced fluids, with GORs calculated from cumulative fluids. In the latter case, it is common to start the cumulative production numbers at the start of injection. But in some cases, there is value in starting the

cumulative production numbers at the start of production. Figure 3 shows Instantaneous VRR and Cumulative VRR datasets for a sample set of wells.

Figure 3. Instantaneous VRR and Cumulative VRR datasets for a sample set of wells



Due to leaking faults, a poor cement casing bond, discontinuous sands depleted prior to water injection, a gas cap, or an inactive aquifer, it is common to lose some of the injected water to areas outside of the floodable pore volume.

If the Instantaneous VRR for a given month is equal to or greater than 1.0, the reservoir pressure is being maintained or increased for the month. If the ratio is less than 1.0, the reservoir pressure declines for the month. When computing the reservoir voidage, it should not be assumed that the free gas term is negligible without making appropriate calculations.

As long as cumulative VRR is equal to or greater than 1.0, after taking into account injection losses, reservoir pressure since the start of water injection will be maintained or increased. When the cumulative VRR calculated since the start of production reaches 1.0, reservoir pressure will have increased to near original reservoir pressure (p_i).

Typecurve theory

Typecurve theory includes the following:

- Agarwal-Gardner
- Blasingame
- Compound Linear
- Fetkovich
- NPI
- Transient
- Wattenbarger

Agarwal-Gardner typecurve theory

Agarwal and Gardner have compiled and presented decline typecurves for analyzing production data. Their methods build upon the work of Fetkovich, Palacio, and Blasingame, using the concepts of the equivalence between constant rate and constant pressure solutions. Agarwal and Gardner present typecurves with dimensionless variables based on the conventional welltest definitions, as opposed to the Fetkovich dimensionless definitions used by Blasingame et al. They also include primary and semi-log pressure derivative plots (in inverse format for decline analysis). Furthermore, they present their decline curves in additional formats to the standard normalized rate vs. time plot. These include the rate vs. cumulative, and cumulative vs. time analysis plots.

Rate-cumulative production analysis

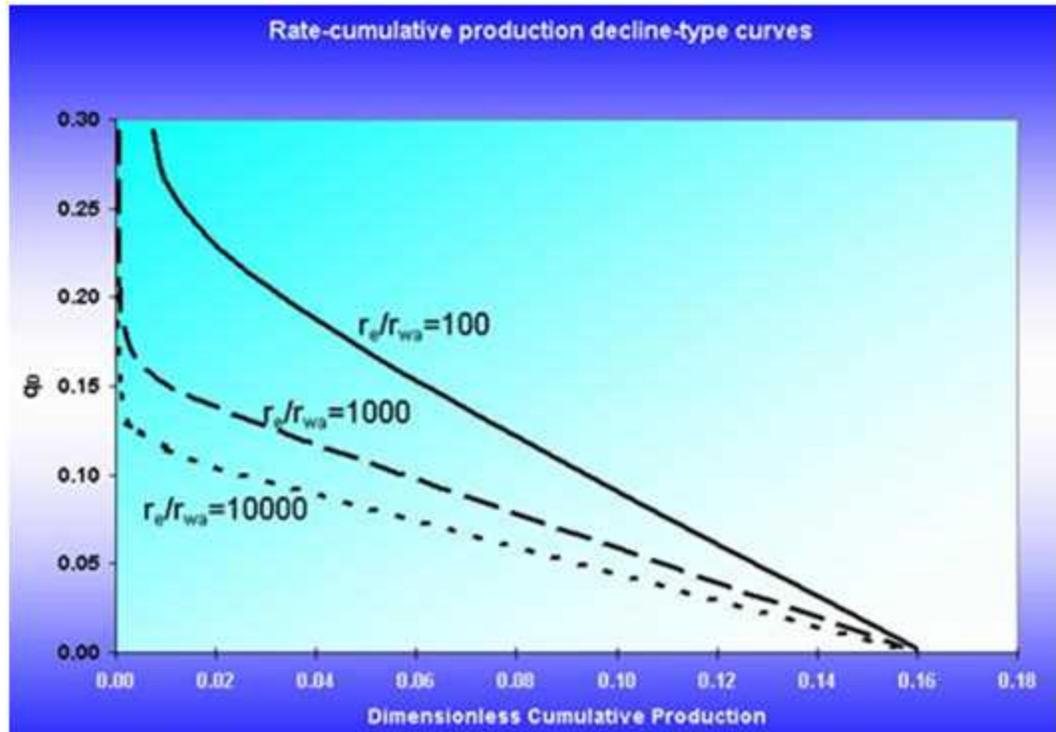
Dimensionless typecurves

Agarwal et al. propose the use of rate-cumulative typecurves for estimating gas- or oil-in-place. Dimensionless rate (q_D) is plotted against dimensionless cumulative production (Q_{DA}), which is defined as follows

$$Q_{DA} = \frac{t_{DA}}{p_D} = q_D t_{DA}$$

The resulting typecurves are straight lines on a Cartesian graph, which are anchored at the point 0.159, as shown in the following figure. A plot of dimensionless rate vs. dimensionless cumulative

production yields a straight line that passes through $Q_{DA} = 0.159$ at $q_D = 0$, provided that fluid-in-place has been estimated correctly.



Modifications in RTA

The presentation of rate-cumulative analysis in rate transient analysis (RTA) is modified significantly from that of Agarwal and Gardner. See [methodology: rate-cumulative](#).

Data Preparation

The rate vs. cumulative production analysis is performed to estimate the hydrocarbons-in-place.

Oil wells

Plot pressure-drop normalized flow rate ($q / \Delta p$) vs. modified cumulative production on Cartesian coordinates, where:

$$Q_m = \frac{N_p}{c_t(p_i - p_{wf})}$$

Gas wells

Estimate original gas-in-place (a lower bound estimate can be obtained by performing a straight line extrapolation on a rate vs. cumulative production plot. Another estimate is the volumetric gas-in-place).

Plot pressure-drop normalized flow rate vs. modified cumulative production on Cartesian coordinates, where:

$$Q_m = \frac{G(p_{pi} - \bar{p}_p)}{(p_{pi} - p_{wf})} = \frac{2qt_{ca}p_i}{(c_t \mu Z)_i (p_{pi} - p_{pwf})}$$

Analysis

Oil wells

Perform a straight line extrapolation of the data. The value where the extrapolated line crosses the x-axis is the original oil-in-place.

Gas wells

Perform a straight line extrapolation of the data. If the extrapolated line crosses the x-axis short of the estimated gas-in-place, choose a smaller gas-in-place input value. If the extrapolated line crosses the x-axis beyond the estimated gas-in-place, choose a larger gas-in-place input value. Then, re-calculate the material balance pseudo-time function and re-plot the data.

Rate-time production analysis

Dimensionless typecurves

The Agarwal-Gardner rate-time analysis plot includes dimensionless typecurves, based on the constant rate solution. Unlike Blasingame, these typecurves are graphed using the well-test variables dimensionless rate and dimensionless time. Agarwal and Gardner also include typecurves for the primary pressure derivative and semi-logarithmic (well-test) derivative (plotted as an inverse). The result is a diagnostic analysis that clearly shows the transition point from transient to boundary-dominated flow. The dimensionless pressure for standard well-test analysis is defined as:

$$p_D = \frac{kh(p_i - p_{wf})}{141.2qB\mu}$$

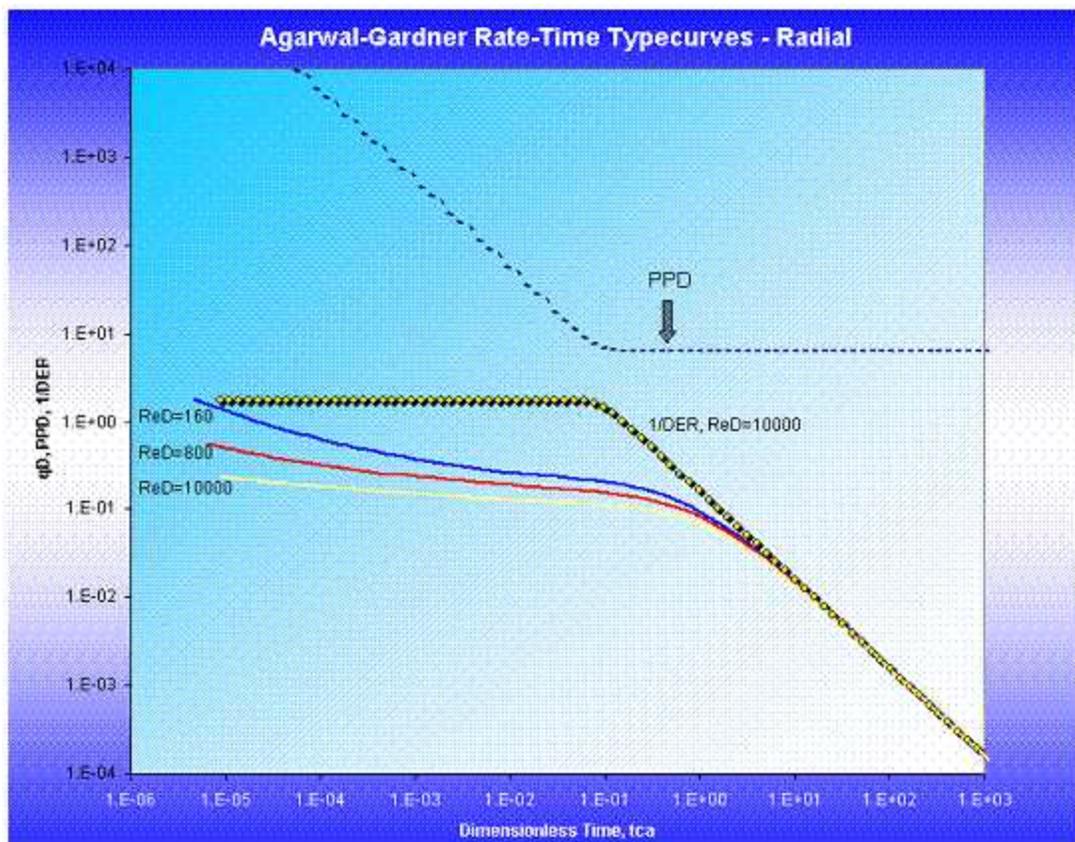
The dimensionless flow rate is simply the inverse of the previous equation (note that in the well-test literature, dimensionless rate has a slightly different definition):

$$q_D = \frac{1}{p_D}$$

The primary and semi-log (inverse) derivative typecurves are as follows:

$$\frac{\partial p_D}{\partial t_D} \text{ and } \frac{1}{\partial p_D / \partial \ln t_D}$$

The resulting dimensionless typecurve plot is shown below.

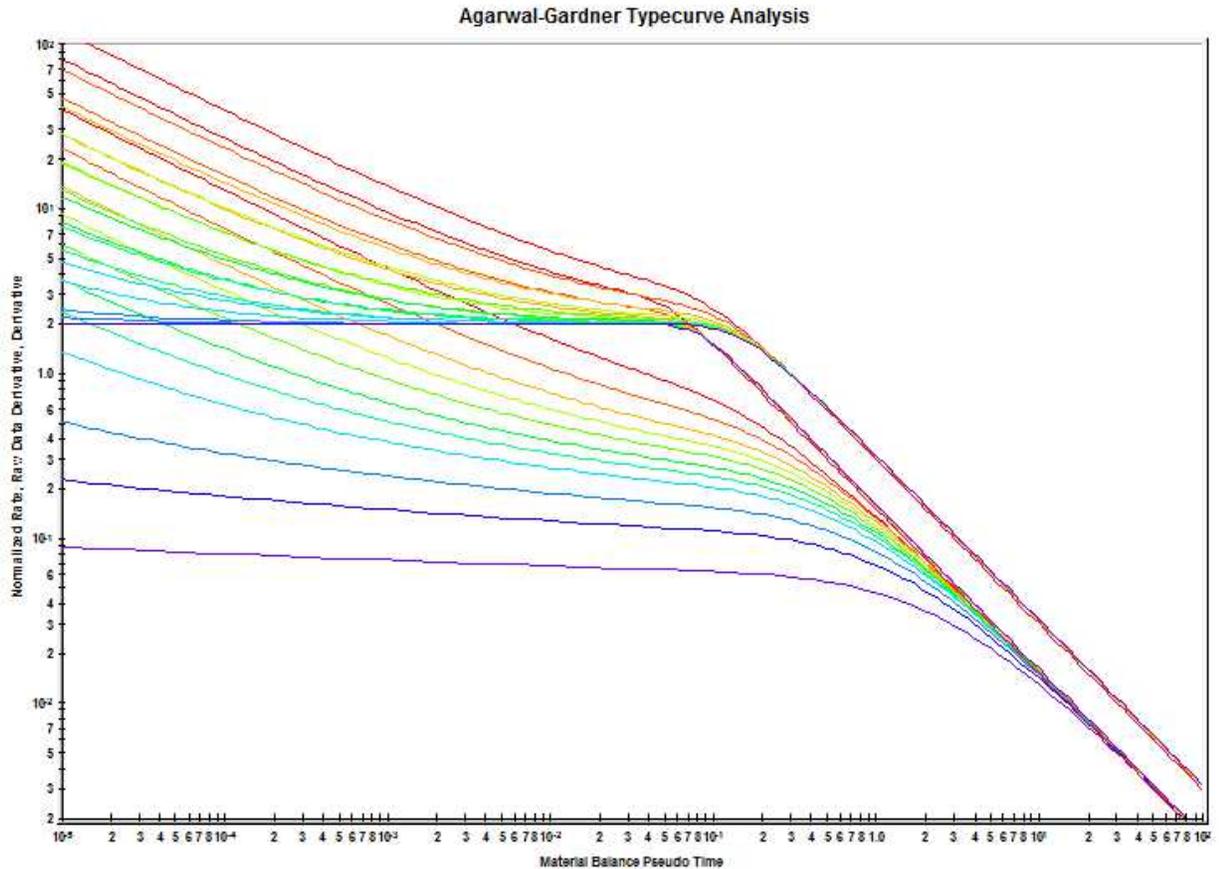


Modifications in RTA

In RTA, this analysis has been modified slightly; In addition to the semi-log derivative, a semi-log *integral* derivative curve is included. The advantage of the integral derivative curve is that the

data has far less scatter, while retaining a shape identical to the semi-log derivative, only offset in the time scale.

The RTA rendition of the Agarwal-Gardner Rate-Time plot is shown below. Note that the primary pressure derivative plot is not included in the RTA presentation.



Data preparation

The horizontal axis is material balance time (pseudo-time for gas); the vertical axis is either normalized rate or inverse of semi-log derivative.

Oil wells

$$t_c = \frac{N_p}{q}$$

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

$$\frac{1}{\partial} = \frac{1}{\left(\frac{\frac{\partial \Delta p}{q}}{\partial \ln t_c} \right)}$$

Gas wells

$$t_{ca} = \frac{\mu_i c_{ti}}{q(t)} \int_0^t \frac{q(t)}{\mu(\bar{p}) c_t(\bar{p})} dt$$

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

$$\frac{1}{\partial} = \frac{1}{\left(\frac{\frac{\partial \Delta p_p}{q}}{\partial \ln t_{ca}} \right)}$$

Analysis

The normalized rate and inverse semi-log derivative data are plotted against material balance time on a log-log scale of the same size as the typecurves. This plot is called the "data plot". Any convenient units can be used for normalized rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates; especially when transient data sets are analyzed.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and its r_e/r_{wa} (r_e/x_f for fractured case) value is noted.

Typecurve analysis is done by selecting a match point, and reading its coordinates off the data plot ($q/\Delta p$ and t_c)_{match}, and the typecurve plot (q_D and t_{DA})_{match}. At the same time the stem value r_e/r_{wa} (r_e/x_f for fracture typecurves) of the matching curve is noted. To create a forecast, the selected typecurve is traced on to the data plot, and extrapolated. The future rate is read from the data plot, off the traced typecurve.

In the modified (RTA) plot, the inverse pressure integral derivative is also included.

Calculation of parameters

Radial typecurves

Oil wells

Using the definition of dimensionless rate:

$$q_D = \frac{141.2qB\mu}{kh(p_i - p_{wf})}$$

Permeability is calculated as follows, where pressure-drop normalized flow rate and dimensionless rate are read off each of the raw data and typecurve graphs at a selected match point:

$$k = \frac{141.2B\mu}{h} \left(\frac{q/\Delta p}{q_D} \right)_{match}$$

From the definition of dimensionless time based on area (t_{DA}):

$$t_{DA} = \frac{0.00633kt_c}{\pi\phi\mu c_t r_e^2}$$

Reservoir radius is calculated as follows:

$$r_e = \sqrt{\frac{0.00633k}{\pi\phi\mu c_t} \left(\frac{t_c}{t_{DA}} \right)_{match}}$$

Substituting the equation for permeability into the above:

$$r_e = \sqrt{\frac{0.00633}{\pi\phi c_t} \left(\frac{141.2B}{h} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_{DA}} \right)_{match}}$$

Additional reservoir parameters are now calculated:

$$r_{wa} = \frac{r_e}{(r_e/r_{wa})_{match}}$$

$$A [acres] = \frac{\pi r_e^2}{43560}$$

$$s = \ln \frac{r_w}{r_{wa}}$$

$$N [Mbbbls] = \frac{\pi r_e^2 \phi s_o h}{B_o} \left(\frac{1}{5615} \right) = \frac{0.00633}{c_t} \left(\frac{141.2 s_o}{5615} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_{DA}} \right)_{match}$$

Gas wells

For gas wells, dimensionless rate is defined as follows:

$$q_D = \frac{1.417 \cdot 10^6 T}{kh} \left(\frac{q}{\Delta p_p} \right)$$

According to this equation, the permeability can be calculated as:

$$k = \frac{1.417 \cdot 10^6 T}{h} \left(\frac{q/\Delta p_p}{q_D} \right)_{match}$$

From the definition of dimensionless time based on area:

$$t_{DA} = \frac{0.00633 k t_{ca}}{\pi \phi \mu_i c_{ti} r_e^2}$$

Reservoir radius is calculated as follows:

$$r_e = \sqrt{\frac{0.00633 k}{\pi \phi \mu_i c_{ti}} \left(\frac{t_{ca}}{t_{DA}} \right)_{match}}$$

Substituting the equation for permeability into the above:

$$r_e = \sqrt{\frac{0.00633}{\pi \phi \mu_i c_{ti}} \left(\frac{1.417 \cdot 10^6 T}{h} \right) \left(\frac{q/\Delta p_p}{q_D} \right)_{match} \left(\frac{t_{ca}}{t_{DA}} \right)_{match}}$$

Additional reservoir parameters are now calculated:

$$r_{wa} = \frac{r_e}{(r_e/r_{wa})_{match}}$$

$$A [acres] = \frac{\pi r_e^2}{43560}$$

$$s = \ln \frac{r_w}{r_{wa}}$$

$$G [bcf] = \left[\frac{\pi r_e^2 \phi h S_g p_i T_{sc}}{Z_i T p_{sc}} \right] * 10^{-9}$$

$$= \left[\frac{0.0633 * 1.417 * 10^6 S_g p_i T_{sc}}{\mu_i c_{ti} Z_i p_{sc}} \left(\frac{q/\Delta p_p}{q_D} \right)_{match} \left(\frac{t_{ca}}{t_{DA}} \right)_{match} \right] * 10^{-9}$$

Fracture typecurves

Oil wells

Using the definition of dimensionless rate:

$$q_D = \frac{141.2qB\mu}{kh(p_i - p_{wf})}$$

Permeability is calculated as follows, where pressure-drop normalized flow rate and dimensionless time are read off each of the raw data and typecurve graphs at a selected match point:

$$k = \frac{141.2B\mu}{h} \left(\frac{q/\Delta p}{q_D} \right)_{match}$$

From the definition of dimensionless time based on area:

$$t_{DA} = \frac{0.00633kt_c}{\pi\phi\mu c_t r_e^2}$$

Reservoir radius is calculated as follows:

$$r_e = \sqrt{\frac{0.00633k}{\pi\phi\mu c_t} \left(\frac{t_c}{t_{DA}}\right)_{match}}$$

Substituting the equation for permeability into the above:

$$r_e = \sqrt{\frac{0.00633}{\pi\phi c_t} \left(\frac{141.2B}{h}\right) \left(\frac{q/\Delta p}{q_D}\right)_{match} \left(\frac{t_c}{t_{DA}}\right)_{match}}$$

Additional reservoir parameters are now calculated:

$$x_f = \frac{r_e}{(r_e/x_f)_{match}}$$

$$A [acres] = \frac{\pi r_e^2}{43560}$$

$$N [Mbbls] = \frac{\pi r_e^2 \phi S_o h}{B_o} \left(\frac{1}{5615}\right) = \frac{0.00633}{c_t} \left(\frac{141.2 S_o}{5615}\right) \left(\frac{q/\Delta p}{q_D}\right)_{match} \left(\frac{t_c}{t_{DA}}\right)_{match}$$

Gas wells

For gas wells, dimensionless rate is defined as follows:

$$q_D = \frac{1.417 \cdot 10^6 T}{kh} \left(\frac{q}{\Delta p_p}\right)$$

The permeability is calculated from above, as follows:

$$k = \frac{1.417 \cdot 10^6 T}{h} \left(\frac{q/\Delta p_p}{q_D}\right)_{match}$$

From the definition of dimensionless time based on area:

$$t_{DA} = \frac{0.00633 k t_{ca}}{\pi \phi \mu_i c_{ti} r_e^2}$$

Reservoir radius is calculated as follows:

$$r_e = \sqrt{\frac{0.0633k}{\pi\phi\mu_i c_{ti}} \left(\frac{t_{ca}}{t_{DA}}\right)_{match}}$$

Substituting the equation for permeability into the above, we get:

$$r_e = \sqrt{\frac{0.00633}{\pi\phi\mu_i c_{ti}} \left(\frac{1.417*10^6 T}{h}\right) \left(\frac{q/\Delta p_p}{q_D}\right)_{match} \left(\frac{t_{ca}}{t_{DA}}\right)_{match}}$$

Additional reservoir parameters are now calculated:

$$x_f = \frac{r_e}{(r_e/x_f)_{match}}$$

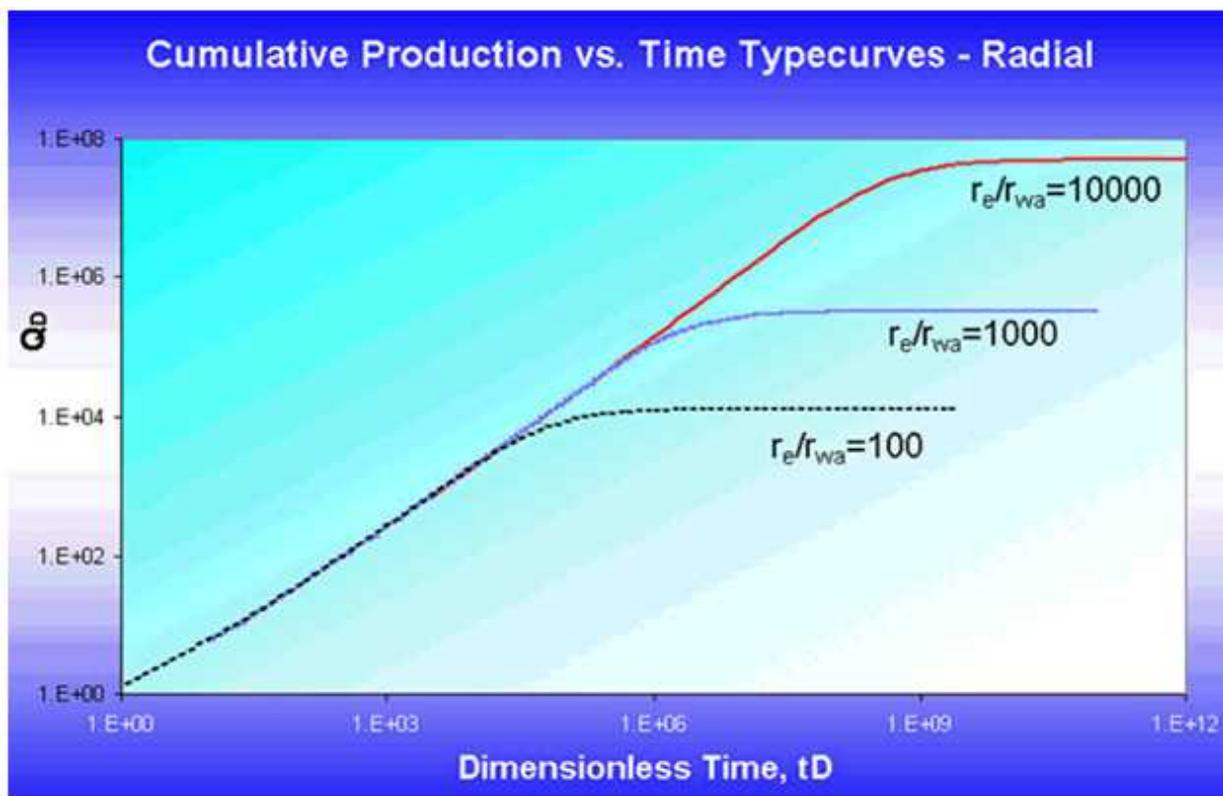
$$A [acres] = \frac{\pi r_e^2}{43560}$$

$$G [bcf] = \left[\frac{\pi r_e^2 \phi h S_g p_i T_{sc}}{Z_i T p_{sc}} \right] * 10^{-9}$$

$$= \left[\frac{0.00633 * 1.417 * 10^6 S_g p_i T_{sc}}{\mu_i c_{ti} Z_i p_{sc}} \left(\frac{q/\Delta p_p}{q_D}\right)_{match} \left(\frac{t_{ca}}{t_{DA}}\right)_{match} \right] * 10^{-9}$$

Methodology: rate-cumulative

Cumulative-time typecurves have a similar purpose to the rate-time typecurves, but have the added advantage of smoothing noisy production data. As such, they often help to provide a more unique type curve match, when used in conjunction with the other Agarwal-Gardner typecurves. The following figure is an example of a cumulative-time typecurve for an unfractured well in a circular reservoir:



Plotting rate vs. cumulative production is a widely accepted and simple method for estimating movable reserves. In the absence of more sophisticated decline analysis techniques, many analysts use this method as a quick and effective way of estimating reserves. A straight-line extrapolation is equivalent to fitting the data to the exponential ($b = 0$) stem of the Arps decline typecurves. This method will almost always give a lower-bound estimate of recoverable hydrocarbons (this can be clearly seen when looking at the Arps decline typecurves, as the exponential stem has the steepest slope). A more rigorous decline analysis can be performed by fitting data to one of the full set of Arps decline typecurves. This type of analysis provides an empirical fit of the data to estimate the recoverable reserves.

There are two main limitations of the Arps decline analysis technique:

- The analysis does not account for changing production conditions, and thus cannot always provide a reliable estimate of recoverable hydrocarbons-in-place.
- Changing gas properties with time (reservoir pressure) are not accounted for; thus gas reserves are usually underestimated.

These limitations can be overcome through modification of the rate vs. cumulative production plotting functions. Changing production conditions are accommodated by incorporating

variations in flowing pressure as well as production rate, and by normalizing the production data using material balance time. Changing gas properties are handled using gas pseudo-time.

Blasingame typecurve theory

Background

The production decline analysis techniques of Arps and Fetkovich are limited in that they do not account for variations in sandface flowing pressure in the transient regime, and only account for such variations empirically during boundary-dominated flow (by means of the empirical depletion stems). In addition, changing pressure, volume, and temperature (PVT) properties with reservoir pressure are not considered for gas wells.

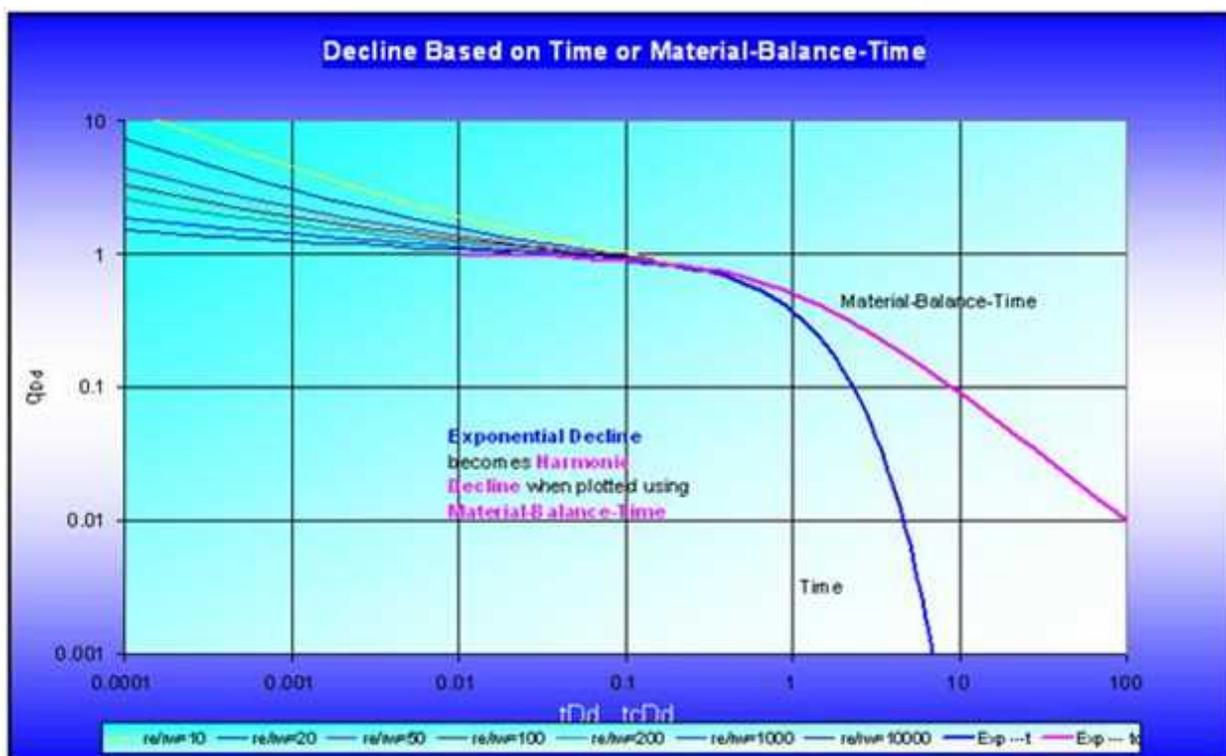
Blasingame and his colleagues have developed a production decline method that accounts for these phenomena. The method uses a form of superposition time function that only requires one depletion stem for typecurve matching - the harmonic stem. One important advantage of this method is that the typecurves used for matching are similar to those used for Fetkovich decline analysis, without the empirical depletion stems. When the typecurves are plotted using Blasingame's superposition time function, the analytical exponential stem of the Fetkovich typecurve becomes harmonic. The significance of this may not be readily evident until considering that, if the inverse of the flowing pressure is plotted against time, pseudo-steady state depletion at a constant flow rate follows a harmonic decline trend. In effect, Blasingame's typecurves allow depletion at a constant pressure to appear as if it were depletion at a constant flow rate. In fact, Blasingame et al. have shown that boundary-dominated flow with both declining rates and pressures appear as pseudo-steady state depletion at a constant rate, provided the rate and pressure decline monotonically.

Blasingame's improvements on the Fetkovich style of production decline analysis are further enhanced by the introduction of two additional typecurves which are plotted concurrently with the normalized rate typecurve. These 'rate integral' and 'rate integral derivative' typecurves aid in obtaining a more unique match. The derivation of these will be discussed in a later section.

Blasingame in RTA

Recall that the Fetkovich typecurves are based on combining the analytical solution to transient flow of a single-phase fluid at a constant wellbore flowing pressure with the empirical Arps equations for boundary-dominated flow. Fetkovich believed the exponent 'b' could vary between zero and one, and that it was correlatable with fluid properties as well as recovery mechanism. For example, single-phase oil flow would result in a 'b' value of zero, while single-phase gas flow would exhibit 'b' > 0 because of changes in gas properties. Later, Fraim and Wattenbarger showed

that if the changes in gas fluid properties were taken into account (i.e., with the use of pseudo-time), boundary-dominated gas flow against a constant back pressure exhibits the same behavior that an oil reservoir would; the decline would follow the exponential curve, in which 'b' = 0. These findings relate to flow at constant wellbore pressure. The subsequent development by Blasingame et al. was to account for changing wellbore flowing pressures by defining a superposition time function, which they called material balance time. They showed that if the material balance time were used instead of actual producing time, what was previously an exponential decline would follow the harmonic decline stem instead.

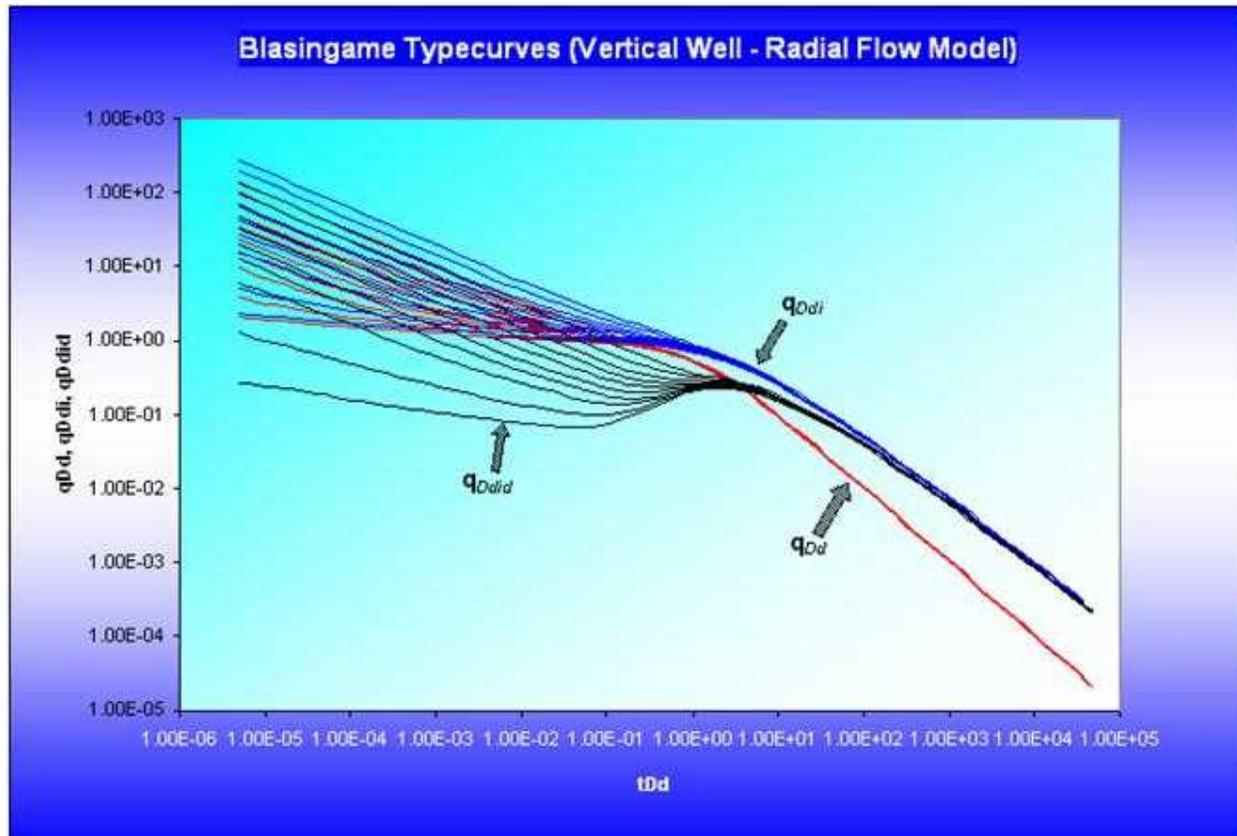


More importantly, data obtained when both the rate and the flowing pressure are varying can now be analyzed if material balance time is used. For example, if the production rate from a well is monotonically declining, and at the same time, its flowing sandface pressure is on continuous decline, a plot of pressure-drop normalized flow rate ($q / \Delta p$) vs. $Q(t) / q(t)$ would follow the harmonic curve (for a gas well, the changing gas properties should also be accounted for by using pseudo-time).

Blasingame, McCray, and Palacio developed typecurves which show the analytical transient stems along with the analytical harmonic decline (but with the rest of the empirical hyperbolic stems absent). In addition, they introduced two other functions; the rate integral function, and

the rate integral derivative function, which help in smoothing the often noisy character of production data, and in obtaining a more unique match.

The Blasingame suite of typecurves are similar to the Fetkovich typecurves for constant pressure production. The only real difference is the absence of the empirical depletion stems on the Blasingame typecurves. These are not required because the usage of material balance time forces the boundary-dominated data to fall only on the analytical harmonic stem.



Models

The Blasingame suite of typecurves consists of a number of different models:

- Vertical well; radial flow model
- Vertical well; hydraulic fracture model (Infinite conductivity)
- Vertical well; hydraulic fracture model (Finite conductivity)
- Vertical well; hydraulic fracture model (Elliptical flow)
- Horizontal well model

- Waterflood model
- Well interference model (declining reservoir pressure)

All models assume a circular outer boundary, with the exception of Elliptical flow and Horizontal well typecurves, which assume an elliptical and a square outer boundary, respectively.

Methodology

In Blasingame typecurve analysis, three rate functions (normalized rate, rate integral, and rate integral derivative) can be plotted against Material Balance Time.

Normalized rate

Normalized rate is the primary plotting variable. It is very useful for production analysis where flowing pressures and rates change through time. It is defined as the rate divided by flowing pressure drop.

Oil

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

Gas

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

Rate integral

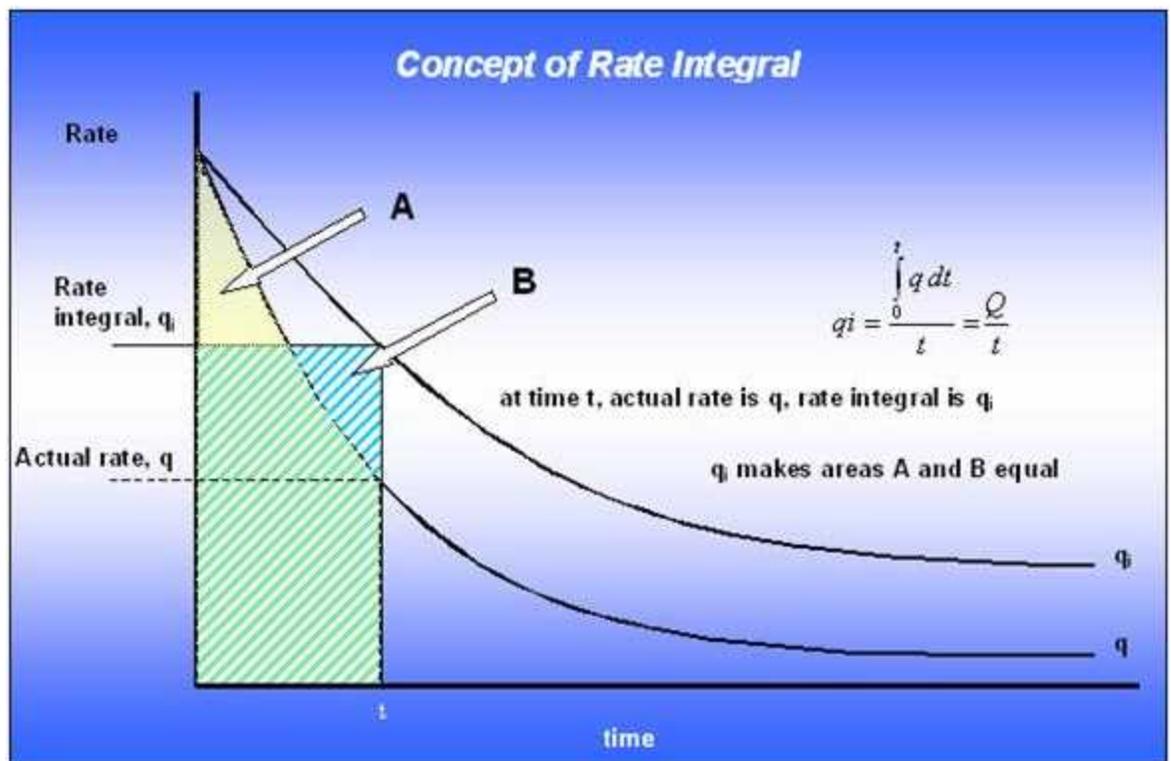
Conceptually, the rate integral may be thought of as the average rate at which the well has produced until any particular moment in time. The definition of the normalized rate integral is the cumulative average of the normalized rate when plotted against material balance time.

Surface (and even bottomhole) measured flowing rate and pressure data inherently contain a significant noise component. This noise often masks or distorts the sought after "reservoir signal". As a result, it is advantageous to have a way to remove this noise from the production data response.

Blasingame has identified a powerful method for removing noise from a production response, by using integration. The rate integral (the inverse of this is the pressure integral) is referred to as an auxiliary function, and is derived by integrating the normalized production rate response through time. Any discontinuities in the raw data are effectively removed through the integration process,

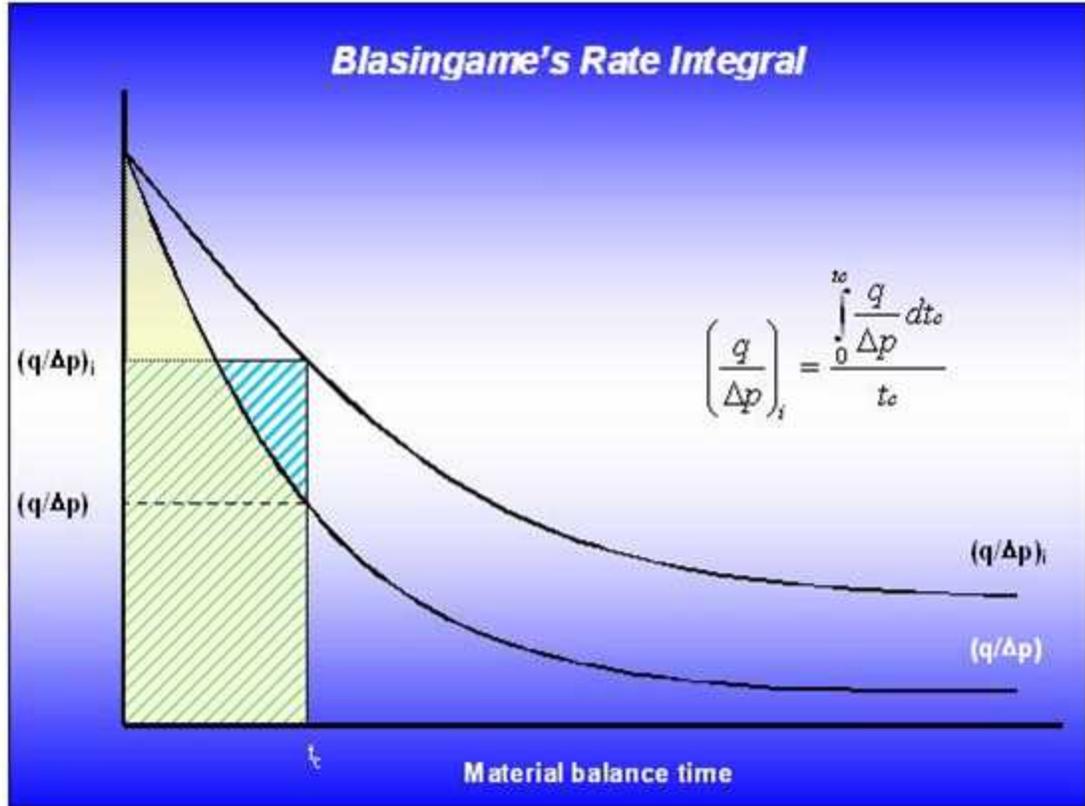
yielding a smooth decline curve. The resulting curve resembles the original production decline response, but is much smoother. It can be used to perform a secondary typecurve match (simultaneously with the raw data). Furthermore, it may be used as base data for a well-test style semi-log derivative plot.

Conceptually, the rate integral function can be thought of as a cumulative average of the flow rate with time. The purpose of plotting a rate integral function is to smooth noisy rate data. This concept is most easily understood graphically:



In terms of Blasingame typecurve analysis, the definition of the rate integral must account for two additional complications:

- Normalization of flow rate using pressure (for oil) or pseudo-pressure (for gas)
- Usage of material balance time (for oil) or material balance pseudo-time (for gas), instead of time



Oil

$$\left(\frac{q}{\Delta p}\right)_i = \frac{\int_0^{t_c} \frac{q}{\Delta p} dt_c}{t_c}$$

Gas

$$\left(\frac{q}{\Delta p_p}\right)_i = \frac{\int_0^{t_{ca}} \frac{q}{\Delta p_p} dt_{ca}}{t_{ca}}$$

Rate integral derivative

The rate integral derivative is defined as the semi logarithmic derivative of the rate integral function, with respect to material balance time.

Oil

$$\left(\frac{q}{\Delta p}\right)_{id} = -\frac{d\left(\frac{q}{\Delta p}\right)_i}{d \ln t_c} = -\frac{d\left(\frac{q}{\Delta p}\right)_i}{dt_c} t_c$$

Gas

$$\left(\frac{q}{\Delta p_p}\right)_{id} = -\frac{d\left(\frac{q}{\Delta p_p}\right)_i}{d \ln t_{ca}} = -\frac{d\left(\frac{q}{\Delta p_p}\right)_i}{dt_{ca}} t_{ca}$$

Calculation of parameters

The actual normalized rate, rate integral, and rate integral derivative are plotted vs. material balance time data on a log-log scale of the same size as the typecurves. This plot is called the data plot. Any convenient units can be used for normalized rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates, especially when transient data is analyzed. Any one of the curves can be used individually but often using more than one curve helps in achieving a more unique match of the data with the typecurves.

Move the data plot over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. The rate, rate integral, and rate integral derivative data should all fit the same corresponding typecurve. Try several different transient typecurves to obtain the best fit of all the data. Select the typecurve that best fits the data, and note and its r_e / r_{wa} value.

Typecurve analysis is done by selecting a match point and reading its coordinates off the data plot ($q / \Delta P$ and t_c for oil, $q / \Delta p_p$ and t_{ca} for gas) _{match}; and off the typecurve plot (q_{Dd} and t_{Dd}) _{match}. Note the stem value r_e / r_{wa} of the matching curve.

Given a curve match, the following reservoir parameters can be obtained if reservoir thickness, total compressibility, and wellbore radius are known:

- Permeability
- Skin
- Fracture half length
- Dimensionless fracture conductivity

- Area
- Original oil- or gas-in-place

To create a forecast, the selected typecurve is traced on to the data plot, and extrapolated beyond the last data points. The future rate is read from the data plot, off the traced typecurve.

Note: The above calculation parameters reflect a vertical well with a radial flow model. Selection of other typecurve models for matching requires some adjustments. For information on other model calculation parameters, see [transient typecurve matching equations](#).

Boundary-dominated flow

Harmonic stem of decline curves

Recall from the derivation of Material Balance Time:

$$\frac{\Delta p}{q} = m t_c + b_{pss}$$

Taking the reciprocal and rearranging provides the same form as the harmonic branch of Arps typecurve:

$$b_{pss} \frac{q}{\Delta p} = \frac{1}{\left(1 + \frac{m t_c}{b_{pss}}\right)}$$

To further show the similarity to the harmonic equation, the equation above can be written as follows:

$$q_{Dd} = \frac{1}{1 + t_{Dd}}$$

where:

$$q_{Dd} = \frac{q/\Delta p}{(q/\Delta p)_i}$$

$$\left(\frac{q}{\Delta p}\right)_i = \frac{1}{b_{pss}}$$

$$t_{Dd} = a_i t_c$$

$$a_i = \frac{m}{b_{pss}}$$

The rearranged material balance time equation is significant; if the pressure-drop normalized flow rate is plotted vs. material balance time, the data will follow the harmonic branch of the Fetkovich or Arps typecurve (regardless of whether production is constant or variable flow rate, or constant or variable sandface pressure).

The relations that are used to compute oil-in-place and reservoir properties are given by Equations A14-A16 of Palacio and Blasingame (1993).

$$b_{pss} = \frac{(q_{Dd})_{match}}{\left(\frac{q_o}{(p_i - p_{wf})}\right)_{match}} \quad (\text{A14})$$

$$m = \frac{1}{N_{c_{ti}}} = b_{pss} \frac{(t_{Dd})_{match}}{(t_c)_{match}} \quad (\text{A15})$$

$$N = \frac{1}{c_{ti}} \frac{(t_c)_{match}}{(t_{Dd})_{match}} \frac{\left(\frac{q_o}{(p_i - p_{wf})}\right)_{match}}{(q_{Dd})_{match}} \quad (\text{A16})$$

Data preparation

In Blasingame typecurve analysis, boundary-dominated flow is represented by a single harmonic stem, into which all the transient stems converge.

To calculate original gas-in-place and original oil-in-place, the plotted data are matched against the harmonic stem, which is defined mathematically as follows:

$$q_{Dd} = \frac{1}{1 + t_{Dd}} \quad (1)$$

Oil

where:

$$q_{Dd} = \frac{\left(\frac{q}{\Delta p}\right)}{\left(\frac{q}{\Delta p}\right)_i}$$

and:

$$t_{Dd} = a_i t_c \quad (2)$$

The pseudo-steady-state equation for oil in decline form is as follows:

$$\frac{q}{\Delta p} = \frac{\frac{1}{b}}{\frac{1}{c_e N b} t_c + 1} \quad (3)$$

Through comparison of (1) and (3), it is clear that a graph of normalized rate vs. material balance time will follow the trend of the dimensionless harmonic stem.

From equations (1), (2), and (3) we get the following:

$$\frac{q}{\Delta p} = \frac{\left(\frac{q}{\Delta p}\right)_i}{1 + a_i t_c} \quad (4)$$

where:

$$\frac{q}{(\Delta p)_i} = \frac{1}{b}$$

$$a_i = \frac{1}{c_e N b}$$

Solving for N, we get:

$$N = \frac{1}{c_e \left(\frac{t_{Dd}}{t_c}\right) \left[\frac{q_{Dd}}{\left(\frac{q}{\Delta p}\right)}\right]} = \frac{1}{c_e} \left[\frac{t_c}{t_{Dd}}\right] \left[\frac{\frac{q}{\Delta p}}{q_{Dd}}\right] \quad (5)$$

Gas

The development for gas is similar to that of oil. However, pseudo-pressure and pseudo-time must be used in place of pressure and time.

The definitions of the dimensionless variables are as follows:

$$q_{Dd} = \frac{\left(\frac{q}{\Delta p_p}\right)}{\left(\frac{q}{\Delta p_p}\right)_i}$$

and:

$$t_{Dd} = a_i t_{ca} \quad (6)$$

The pseudo-steady-state equation for gas is as follows:

$$\frac{q}{\Delta p_p} = \frac{\frac{1}{b}}{\frac{2p_i}{(Z \mu c_t)_i G b} t_{ca} + 1} \quad (7)$$

Combining equations (1), (6) and (7):

$$\frac{q}{\Delta p_p} = \frac{\left(\frac{q}{\Delta p_p}\right)_i}{1 + a_i t_c}$$

where:

$$\left(\frac{q}{\Delta p_p}\right)_i = \frac{1}{b}$$

and:

$$a_i = \frac{2 p_i}{(Z \mu c_t)_i G b} \quad (8)$$

Solving for G, we get:

$$G = \frac{2 p_i}{\left(\frac{t_{Dd}}{t_{ca}}\right) (Z \mu c_t)_i \left(\frac{q_{Dd}}{\frac{q}{\Delta p_p}}\right)} = \frac{2 p_i}{(Z \mu c_t)_i} \left[\frac{t_{ca}}{t_{Dd}} \right] \left[\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right] \quad (9)$$

Transient typecurve matching equations

The evaluation of transient parameters is accomplished using the transient stems of the dimensionless typecurve model. Unlike the boundary-dominated flow case, the definition of the

characteristic dimensionless variables changes according to the chosen transient model. Presented in this section are the typecurve matching equations for five different transient models:

- Radial (Vertical Well)
- Infinite Conductivity Fracture
- Finite Conductivity Fracture
- Horizontal Well
- Elliptical Flow Typecurves

The typecurves are plotted using the dimensionless decline rate q_{Dd} and dimensionless decline time t_{Dd} , which are defined as follows:

$$q_{Dd} = q_D b_{Dpss}$$

where:

$$q_D = \frac{141.2 B \mu}{k h} \frac{q}{\Delta p} \text{ for oil wells}$$

$$q_D = \frac{1.417 \times 10^6 T}{k h} \frac{q}{\Delta p_p} \text{ for gas wells}$$

$$t_{Dd} = \frac{2 \pi}{b_{Dpss}} t_{DA}$$

where:

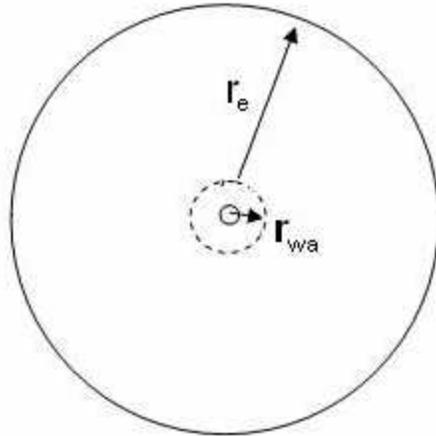
$$t_{DA} = \frac{0.00633 k t_c}{\varphi \mu c_t A} \text{ for oil wells}$$

$$t_{DA} = \frac{0.00633 k t_{ca}}{\varphi \mu_i c_{ti} A} \text{ for gas wells}$$

The dimensionless pseudo-steady state constant b_{Dpss} is defined differently for each model.

Radial

The radial model simulates a vertical well in the center of a cylindrical reservoir.



The characteristic dimensionless parameter $r_{eD} = r_e / r_{wa}$ represents the ratio of the external reservoir radius to the apparent wellbore radius.

The dimensionless pseudo-steady state constant b_{Dpss} is defined as follows for the radial model:

$$b_{Dpss} = \ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{1}{2}$$

Oil

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p} \left(\frac{141.2 B \mu}{k h} \right) b_{Dpss}$$

$$k = \left(\frac{q}{\Delta p} \right)_{match} \left(\frac{141.2 B \mu}{h} \right) b_{Dpss}$$

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633 k t_c}{\frac{1}{2} \varphi \mu c_t r_{wa}^2 \left[\left(\frac{r_e}{r_{wa}} \right)_{match}^2 - 1 \right] b_{Dpss}}$$

$$r_{wa} = \sqrt{\left(\frac{t_c}{t_{Dd}} \right)_{match} \frac{0.00633 k}{\varphi \mu c_t \frac{1}{2} \left[\left(\frac{r_e}{r_{wa}} \right)_{match}^2 - 1 \right] b_{Dpss}}}$$

Skin is calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

Gas

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p_p} \left(\frac{1.417 \times 10^6 T}{k h} \right) b_{Dps}$$

$$k = \frac{1.417 \times 10^6 T}{h} \left[\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right]_{match} b_{Dps}$$

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633 k t_{ca}}{\frac{1}{2} \varphi \mu_i c_{ti} r_{wa}^2 \left[\left(\frac{r_e}{r_{wa}} \right)_{match}^2 - 1 \right]} b_{Dps}$$

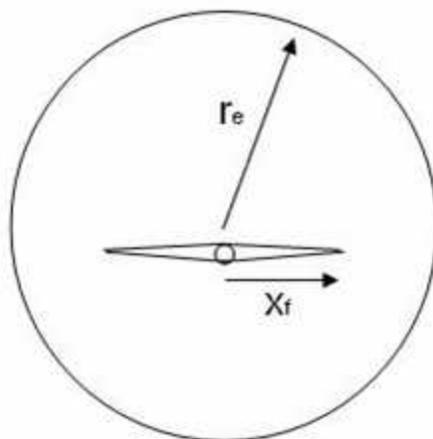
$$r_{wa} = \sqrt{\left(\frac{t_{ca}}{t_{Dd}} \right)_{match} \frac{0.00633 k}{\varphi \mu_i c_{ti} \frac{1}{2} \left[\left(\frac{r_e}{r_{wa}} \right)_{match}^2 - 1 \right]} b_{Dps}}$$

Skin is calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

Infinite conductivity fracture

The fractured model simulates an infinite conductivity hydraulic fracture (vertical) in the center of a cylindrical reservoir.



The characteristic dimensionless parameter $r_{eD} = r_e / x_f$ represents the ratio of external reservoir radius to fracture half-length.

The dimensionless pseudo-steady state constant is defined as follows for the infinite conductivity fracture model:

$$b_{Dpss} = \ln(r_{eD}) - 0.049298 + 0.434645(r_{eD})^{-2}$$

Oil

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p} \left(\frac{141.2 B \mu}{k h} \right) b_{Dpss}$$

$$k = \left(\frac{\frac{q}{\Delta p}}{q_{Dd}} \right)_{match} \left(\frac{141.2 B \mu}{h} \right) b_{Dpss}$$

Solve for effective radius from the product of dimensionless decline rate and dimensionless decline time:

$$r_e = \sqrt{\left(\frac{t_c}{t_{Dd}} \right)_{match} \frac{2}{b_{Dpss}} \frac{0.00633 k}{\varphi \mu c_t}} = \sqrt{\left(\frac{t_c}{t_{Dd}} \right)_{match} \left(\frac{\frac{q}{\Delta p}}{q_{Dd}} \right)_{match} \frac{2 \times 0.00633 \times 141.2 B}{\varphi h c_t}}$$

Solve for fracture half-length from the definition of dimensionless effective radius:

$$x_f = \frac{r_e}{(r_{eD})_{match}}$$

Gas

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p_p} \left(\frac{1.417 \times 10^6 T}{k h} \right) b_{Dpss}$$

$$k = \left(\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right)_{match} \left(\frac{1.417 \times 10^6 T}{h} \right) b_{Dpss}$$

Solve for effective radius from the product of dimensionless decline rate and dimensionless decline time:

$$r_e = \sqrt{0.00633 \left(\frac{1.417 \times 10^6 T}{\frac{1}{2} h \varphi \mu_i c_{ti}} \right) \left(\frac{t_{ca}}{t_{Dd}} \right) \left(\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right)_{match}}$$

Solve for fracture half-length from the definition of dimensionless effective radius:

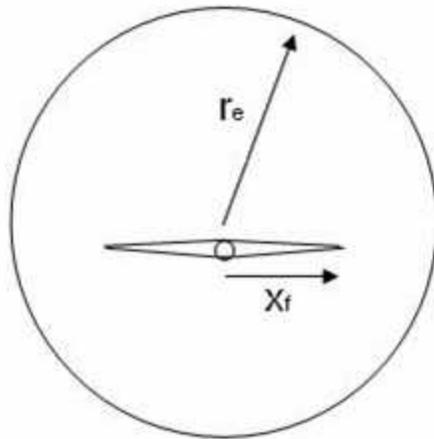
$$x_f = \frac{r_e}{(r_{eD})_{match}}$$

Finite conductivity fracture

A fracture with finite conductivity is defined as a planar crack penetrated by a well or propagated from a well by hydraulic fracturing having a non-zero pressure drop in the fracture during production. A fracture with finite conductivity is characterized by dimensionless fracture conductivity which is defined as:

$$F_{CD} = \frac{k_w w_f}{k x_f}$$

For $F_{CD} > 50$, the fracture is assumed to have infinite conductivity. The finite conductivity fracture model in RTA simulates a vertical fracture in the center of a cylindrical reservoir. The characteristic parameter $r_{eD} = r_e / x_f$ represents the ratio of external reservoir radius to fracture half length.



The dimensionless pseudo-steady state constant b_{Dpss} is defined as follows for the finite conductivity fracture model:

$$b_{Dpss} = \ln(r_{eD}) - 0.049298 + 0.43464 r_{eD}^{-2} + \frac{a_1 + a_2 u + a_3 u^2 + a_4 u^3 + a_5 u^4}{1 + b_1 u + b_2 u^2 + b_3 u^3 + b_4 u^4}$$

where:

$$u = \ln(FCD)$$

$$a_1 = 0.936268$$

$$a_2 = -1.00489$$

$$a_3 = 0.319733$$

$$a4 = -0.0423532$$

$$a5 = 0.00221799$$

$$b1 = -0.385539$$

$$b2 = -0.0698865$$

$$b3 = -0.0484653$$

$$b4 = -0.00813558$$

Oil

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p} \frac{141.2 B \mu}{k h} b_{Dps} s$$

$$k = \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_{Dd}} \right]_{match} \frac{141.2 B \mu}{h} b_{Dps} s$$

Solve for effective radius from the product of dimensionless decline rate and dimensionless decline time:

$$r_e = \sqrt{\left(\frac{t_c}{t_{Dd}} \right)_{match} \frac{2}{b_{Dps}} \frac{0.00633 k}{\varphi \mu c_t}} = \sqrt{\left(\frac{t_c}{t_{Dd}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_{Dd}} \right]_{match} \frac{2 \times 0.00633 \times 141.2 B}{\varphi c_t h}}$$

Solve for fracture half-length from the definition of dimensionless effective radius:

$$x_f = \frac{r_e}{(r_{eD})_{match}}$$

Additional parameters are then calculated using the following equations:

$$N = \frac{0.00633}{c_t} \frac{141.2 S_o}{5.615 \times 10^3} \left(\frac{t_c}{t_{Dd}} \right)_{match} \quad (\text{Mbbl})$$

$$A = \frac{\pi r_e^2}{43560} \quad (\text{Acres})$$

Radial flow skin factor:

$$s \approx \ln \frac{r_w}{x_f} + \frac{1.648546 - 3.002711 \times 10^{-1} u + 1.506532 \times 10^{-1} u^2}{1 + 2.136604 \times 10^{-1} u + 9.513761 \times 10^{-2} u^2 + 8.276998 \times 10^{-3} u^3}$$

where:

$$u = \ln(F_{CD})$$

Gas

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{q}{\Delta p_p} \frac{1.417 \times 10^6 T}{k h} b_{Dpss}$$

$$k = \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_{Dd}} \right]_{match} \frac{1.417 \times 10^6 T}{h} b_{Dpss}$$

Solve for effective radius from the product of dimensionless decline rate and dimensionless decline time:

$$r_e = \sqrt{\left(\frac{t_{ca}}{t_{Dd}} \right)_{match} \frac{2}{b_{Dpss}} \frac{0.00633 k}{\varphi \mu c_t}} = \sqrt{\left(\frac{t_{ca}}{t_{Dd}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_{Dd}} \right]_{match} \frac{2 \times 0.00633 (1.417 \times 10^6)}{\varphi c_t h}}$$

Solve for fracture half-length from the definition of dimensionless effective radius:

$$x_f = \frac{r_e}{(r_{eD})_{match}}$$

Additional parameters are then calculated using the following equations:

$$G = \frac{(1.417 \times 10^6) \times 0.00633 \times 2\pi}{(\mu c_t)_i} \left(\frac{t_{ca}}{t_{Dd}} \right)_{match} \left(\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right)_{match} S_{gi} \times \frac{519.668}{Z_i} \frac{p_i}{14.65} \times E - 9 \text{ (Bscf)}$$

$$A = \frac{\pi r_e^2}{43560} \text{ (Acres)}$$

Radial flow skin factor:

$$s \approx \ln \frac{r_w}{x_f} + \frac{1.648546 - 3.002711 \times 10^{-1} u + 1.506532 \times 10^{-1} u^2}{1 + 2.136604 \times 10^{-1} u + 9.513761 \times 10^{-2} u^2 + 8.276998 \times 10^{-3} u^3}$$

where:

$$u = \ln(\text{FCD})$$

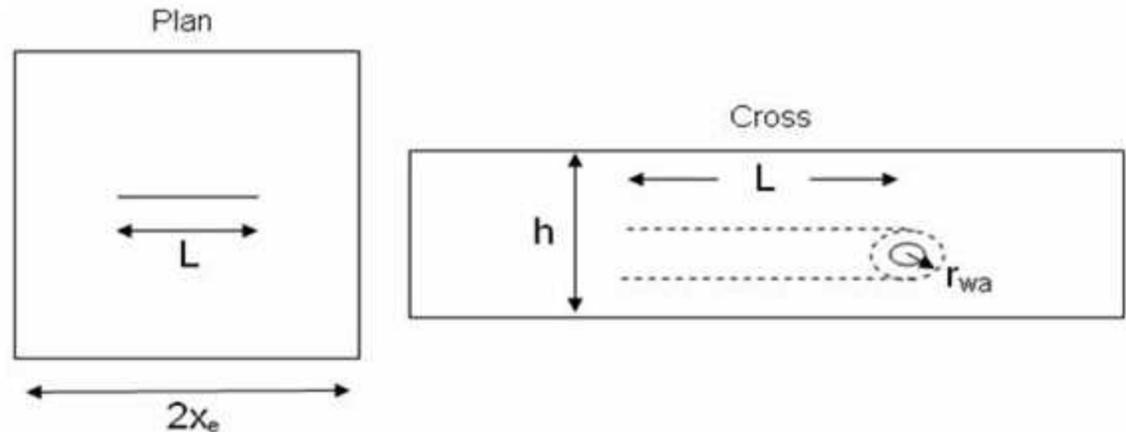
$$u = \ln(\text{FCD})$$

Horizontal well

The horizontal well's typecurve-matching procedure is based on a square-shaped reservoir with uniform thickness (h), and the well is assumed to penetrate the center of the pay zone. Note that

the horizontal well typecurve does *not* include any options for including hydraulic fractures.

The procedure for matching horizontal wells is similar to that of vertical wells. However, for horizontal wells, there is more than one choice of model. Each model presents a suite of typecurves representing a different penetration ratio ($L / 2x_e$) and dimensionless wellbore radius (r_{wD}). The definition of the penetration ratio is illustrated in the following diagram:



$$r_{wD} = \frac{2 r_{wa}}{L}$$

The characteristic dimensionless parameter for each suite of horizontal typecurves is defined as follows:

$$L_D = \frac{L}{2\beta h}$$

where β is the square root of the anisotropic ratio:

$$\beta = \sqrt{\frac{k_h}{k_v}}$$

The dimensionless pseudo-steady state constant b_{Dps} is defined as follows for the horizontal well model:

$$b_{Dps} = \left[\frac{1}{2} \ln \left(\frac{16}{e^\gamma} \frac{1}{C_{Ah}} \frac{4A}{\left(\frac{L}{2x_e}\right)^2} \right) \right]$$

where:

$$\gamma = \text{Euler's constant} = 0.57721$$

Oil

Dimensionless decline rate is defined differently for horizontal oil wells, than for the radial or fractured cases:

$$q_{Dd} = \frac{q}{\Delta p} \left(\frac{141.2 B \mu}{k h} \right) b_{Dps} s$$

Horizontal permeability (k_h) is obtained by rearranging the above definition of dimensionless decline rate:

$$k_h = \left(\frac{\frac{q}{\Delta p}}{q_{Dd}} \right)_{match} \left(\frac{141.2 B \mu}{h} \right) b_{Dps} s$$

Vertical permeability (k_v) is calculated using the anisotropic ratio:

$$k_v = \frac{k_h}{\beta^2}$$

Gas

Dimensionless decline rate is defined differently for horizontal gas wells, than for the radial or fractured cases:

$$q_{Dd} = \frac{q}{\Delta p_p} \left[\frac{(1.417 \times 10^6) B \mu}{k h} \right] b_{Dps} s$$

Now, permeability is obtained by rearranging the above definition of dimensionless decline rate:

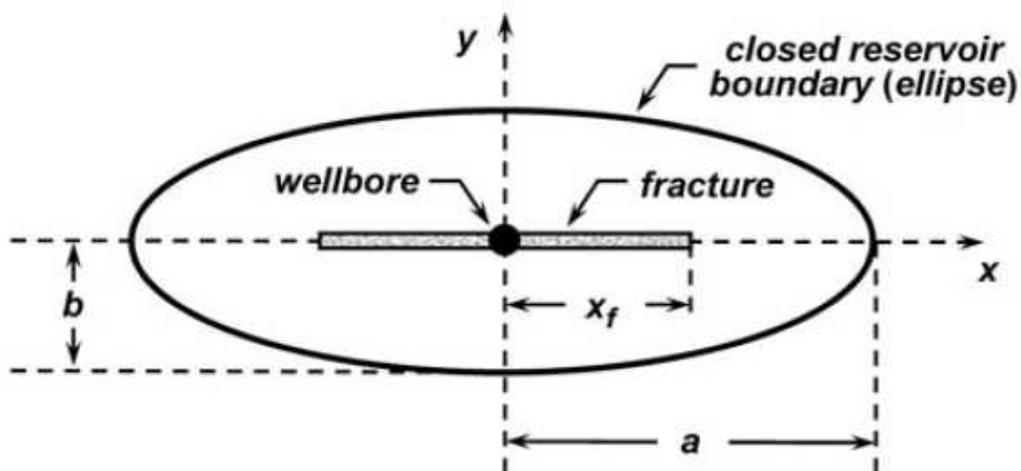
$$k = \left(\frac{\frac{q}{\Delta p_p}}{q_{Dd}} \right)_{match} \left[\frac{(1.417 \times 10^6) B \mu}{h} \right] b_{Dps} s$$

Vertical permeability is calculated exactly the same as for the oil case, using the anisotropic ratio.

Elliptical flow typecurves

Elliptical flow is considered to be the governing flow regime for low permeability gas reservoirs when the reservoir has some sort of an elliptical outer or inner boundary. Cases such as production from an elliptical wellbore, an elliptical fracture, or a circular wellbore in an anisotropic reservoir system can be considered to be examples of an elliptical inner boundary. An elliptic reservoir surrounded by an elliptic aquifer is the example of an elliptical outer boundary.

The elliptical flow typecurves in RTA are generated for a hydraulically fractured well in the center of a reservoir with a closed elliptical boundary.



Schematic of the elliptical reservoir model (Amini et al. 2007).

The following assumptions are made in order to develop these typecurves (Amini et al. 2007):

- The reservoir is assumed to be a single-layer system that is isotropic, horizontal, and uniform thickness with constant reservoir characteristics.
- The fracture is assumed to have elliptical shape. It is also assumed that the fracture is very narrow compared to length of the fracture.
- The elliptical outer boundary is assumed to have a focal length equal to fracture half length.

In the case of infinite conductivity fracture, we do not need to consider the flow in the fracture because of constant pressure along the fracture. However, when we are dealing with a finite conductivity fracture, the flow through fracture should be considered, as the pressure drop within the fracture becomes significant compared to the total pressure drop of the fracture and reservoir. In this case, we should solve the diffusivity equations for reservoir and fracture. However, these equations cannot be solved separately and they are coupled together. In the following sections the diffusivity equation, as well as initial and boundary conditions for reservoir and fracture domains are presented.

Calculation of parameters

Oil wells

Using the definition of dimensionless rate for oil wells:

$$q_D = \frac{141.2 B \mu}{k h} \frac{q}{\Delta p}$$

Permeability is calculated as follows:

$$k = \frac{141.2 B \mu}{h} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D} \right]_{match}$$

From the definition of area-based dimensionless time (t_{DA}) for oil wells:

$$t_{DA} = \frac{0.00633 k t_c}{\varphi \mu c_t A}$$

Area is calculated as follows:

$$A = \frac{0.00633 k}{\varphi \mu c_t} \left(\frac{t_c}{t_{DA}} \right)_{match}$$

Substituting the equation for permeability into the above leads to:

$$A = \left(\frac{t_c}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D} \right]_{match} \frac{0.00633 \times 141.2 B}{\varphi c_t h} \times \frac{1}{43560} \text{ (Acres)}$$

Additional parameters are then calculated using the following equations:

$$N = \left(\frac{t_c}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D} \right]_{match} \frac{0.00633 \times 141.2}{c_t} \frac{S_{oi}}{5.615 \times 10^3} \text{ (Mbbls)}$$

$$x_f = \sqrt{\frac{2A}{\pi \sin(h) (2 \zeta_o)_{match}}} = \sqrt{\frac{2}{\pi \sin(h) (2 \zeta_o)_{match}} \times \left(\frac{t_c}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D} \right]_{match} \frac{0.00633 \times 141.2 B}{\varphi c_t h}}$$

$$a = x_f \cos(h) (\zeta_o)_{match}$$

$$b = x_f \sin(h) (\zeta_o)_{match}$$

$$\text{Drainage Aspect Ratio} = \frac{a}{b} = \cot(h) (\zeta_o)_{match}$$

$$\text{Penetration Ratio} = \frac{x_f}{a} \frac{1}{\cos(h) (\zeta_o)_{match}}$$

$$\text{Where } (\zeta_o)_{match} = \sin(h)^{-1} \left(\frac{b}{x_f} \right)_{match}$$

Gas wells

Using the definition of dimensionless rate for gas wells:

$$q_D = \frac{1.417 \times 10^6 T}{k h} \frac{q}{\Delta p_p}$$

Permeability is calculated as follows:

$$k = \frac{1.417 \times 10^6 T}{h} \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_D} \right]_{match}$$

From the definition of area-based dimensionless time for gas wells:

$$t_{DA} = \frac{0.00633 k t_{ca}}{\varphi \mu c_t A}$$

Area is calculated as follows:

$$A = \frac{0.00633 k}{\varphi \mu c_t} \left(\frac{t_{ca}}{t_{DA}} \right)_{match}$$

Substituting the equation for permeability into the above leads to:

$$A = \left(\frac{t_{ca}}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_D} \right]_{match} \frac{0.00633 \times (1.417 \times 10^6) T}{(\varphi \mu c_t)_i h} \times \frac{1}{43560} \text{ (Acres)}$$

Additional parameters are then calculated using the following equations:

$$G = \left(\frac{t_{ca}}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_D} \right]_{match} \frac{0.00633 \times (1.417 \times 10^6) T}{(\varphi \mu c_t)_i h} \frac{S_{gi}}{5.615 \times 10^3} \times 10^{-9} \text{ (Bscf)}$$

$$x_f = \sqrt{\frac{2A}{\pi \sin(h) (2 \zeta_o)_{match}}} = \sqrt{\frac{2}{\pi \sin(h) (2 \zeta_o)_{match}} \times \left(\frac{t_{ca}}{t_{DA}} \right)_{match} \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_D} \right]_{match} \frac{0.00633 \times (1.417 \times 10^6) T}{(\varphi \mu c_t)_i h}}$$

$$a = x_f \cos(h) (\zeta_o)_{match}$$

$$b = x_f \sin(h) (\zeta_o)_{match}$$

$$\text{Drainage Aspect Ratio} = \frac{a}{b} = \cot(h) (\zeta_o)_{match}$$

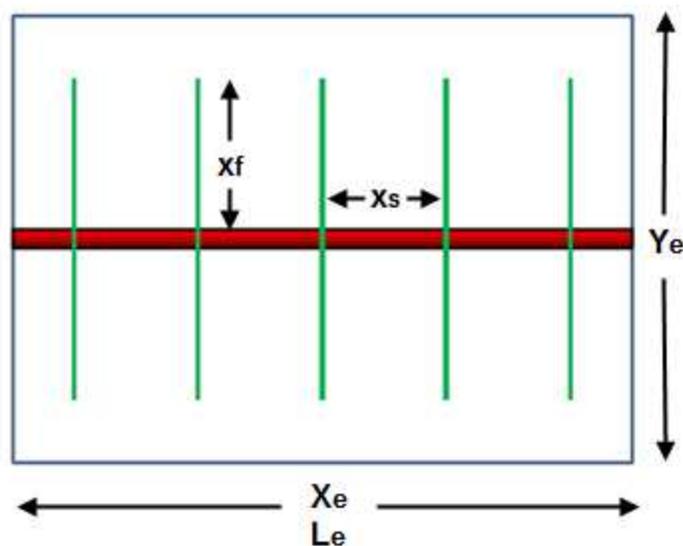
$$\text{Penetration Ratio} = \frac{x_f}{a} = \frac{1}{\cos(h) (\zeta_o)_{match}}$$

$$\text{Where } (\zeta_o)_{match} = \sin(h)^{-1} \left(\frac{b}{x_f} \right)_{match}$$

Compound linear typecurve theory

The most popular well design for exploiting unconventional oil & gas resources is long horizontals with multiple hydraulic fractures. Liang et al (2012) proposed a new set of typecurves for analyzing horizontal multifrac wells with the following geometry:

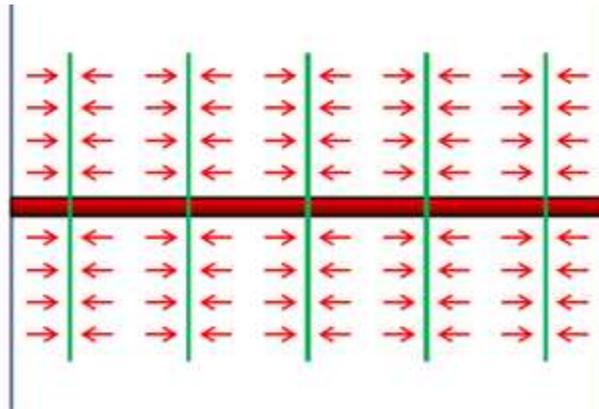
Figure 1: Horizontal Well Geometry



The following six flow regimes have been proposed for such a geometry:

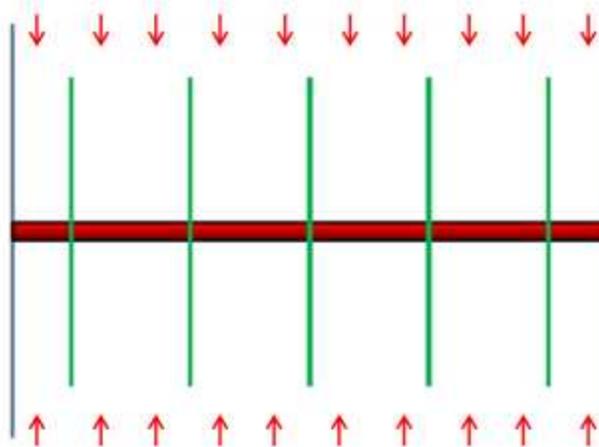
1. Bi-linear flow caused by finite conductivity fractures
2. Primary linear flow from the formation into the fractures

Figure 2



- 3. Transition period between primary linear flow and compound linear flow
- 4. Compound linear flow, which is perpendicular to the primary linear flow

Figure 3



- 5. Transition between compound linear flow and boundary-dominated flow
- 6. Boundary-dominated flow

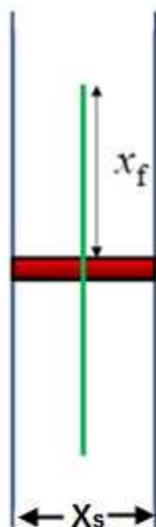
For unconventional reservoirs, the primary flow regimes of interest for rate-transient analysis are the primary linear flow into the fracture, the transition between primary linear and compound linear, and compound linear flow. The compound linear typecurves available in IHS RTA are based on these three flow regimes.

If the following assumptions are made regarding the horizontal multi-fractured well, [Figure 1](#) can be reduced to a single fracture in an infinitely large reservoir:

- Fractures are equally spaced along the horizontal well
- Fractures have the same half-length and conductivity
- The horizontal well contributes negligible flow as compared to the fractures
- The reservoir is a single-layer, homogenous, isotropic system with single porosity and uniform thickness
- The fractures penetrate the entire formation thickness
- The spacing between horizontal wells is infinitely large

With these assumptions in mind, the following reservoir model was used to generate the type-curves:

Figure 4



The complete solution of the above reservoir model is based on Green's function method of Gringarten and Ramey (1974). The dimensionless variables are defined as follows:

$$t_{Dxf} = \frac{0.00633kt}{\phi\mu c_i x_f^2}$$

$$p_D = \frac{\Delta p kh}{141.2qB\mu}$$

The constant rate solution of the equation for various X_s/x_f ratios results in the following set of typecurves for normalized pressure and semi-log derivative (DER):

Figure 5

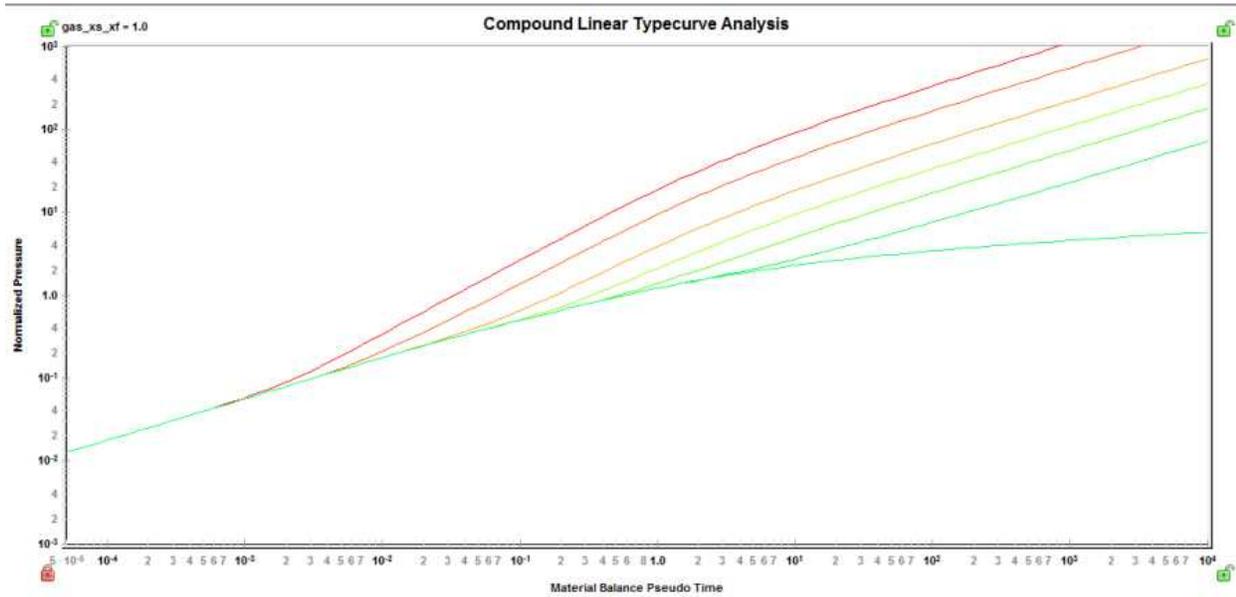
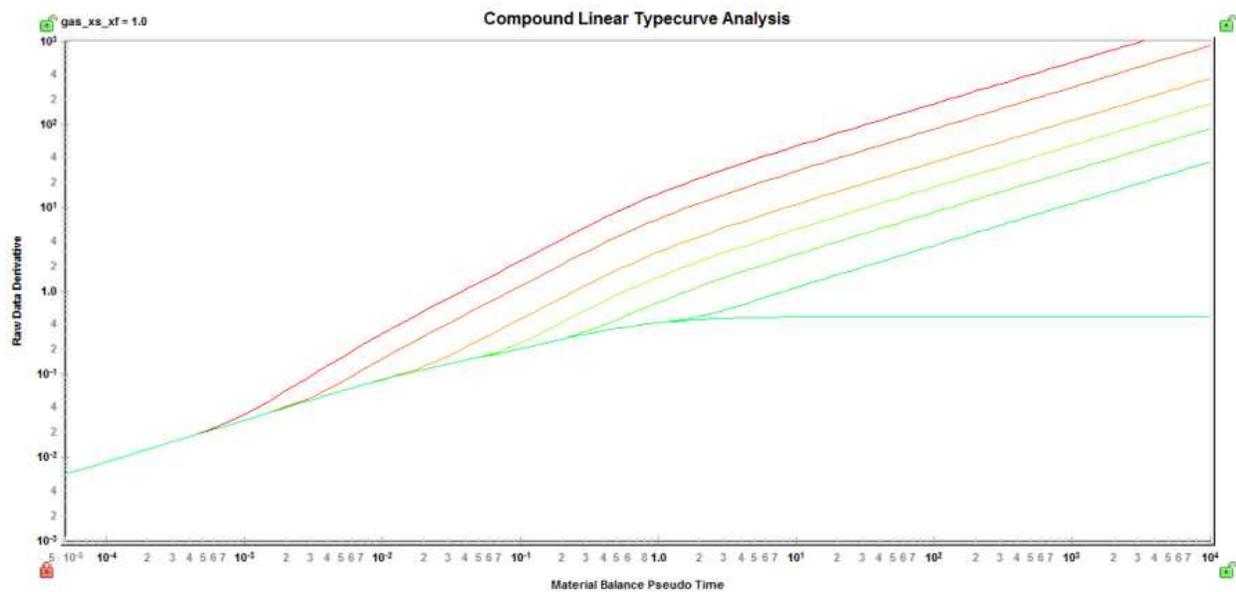
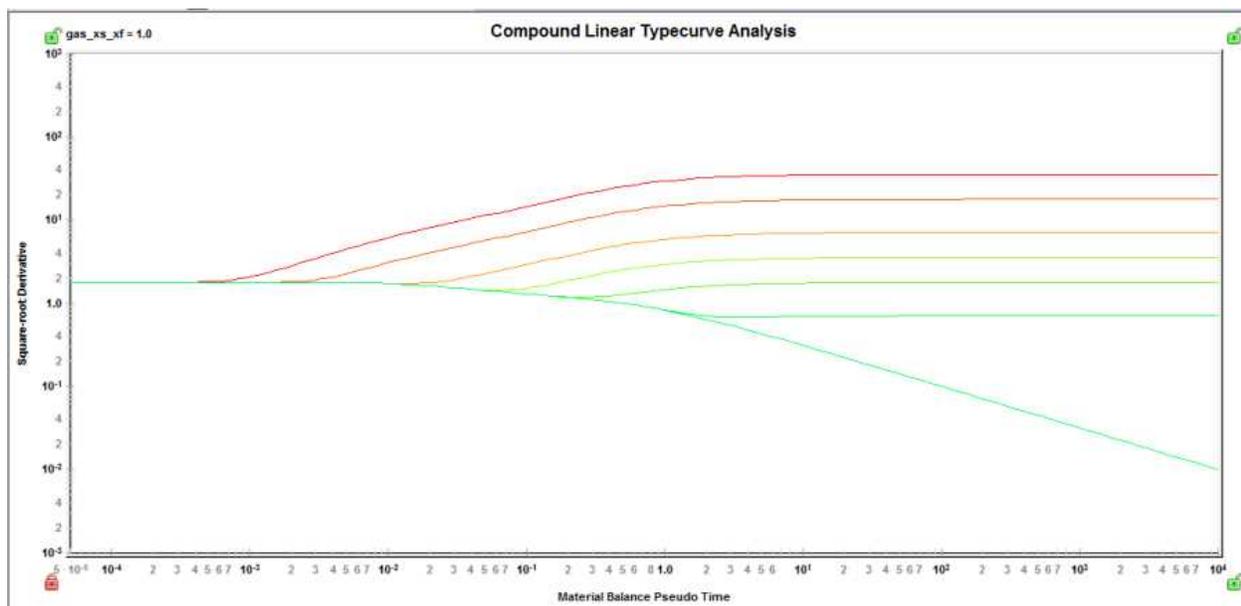


Figure 6

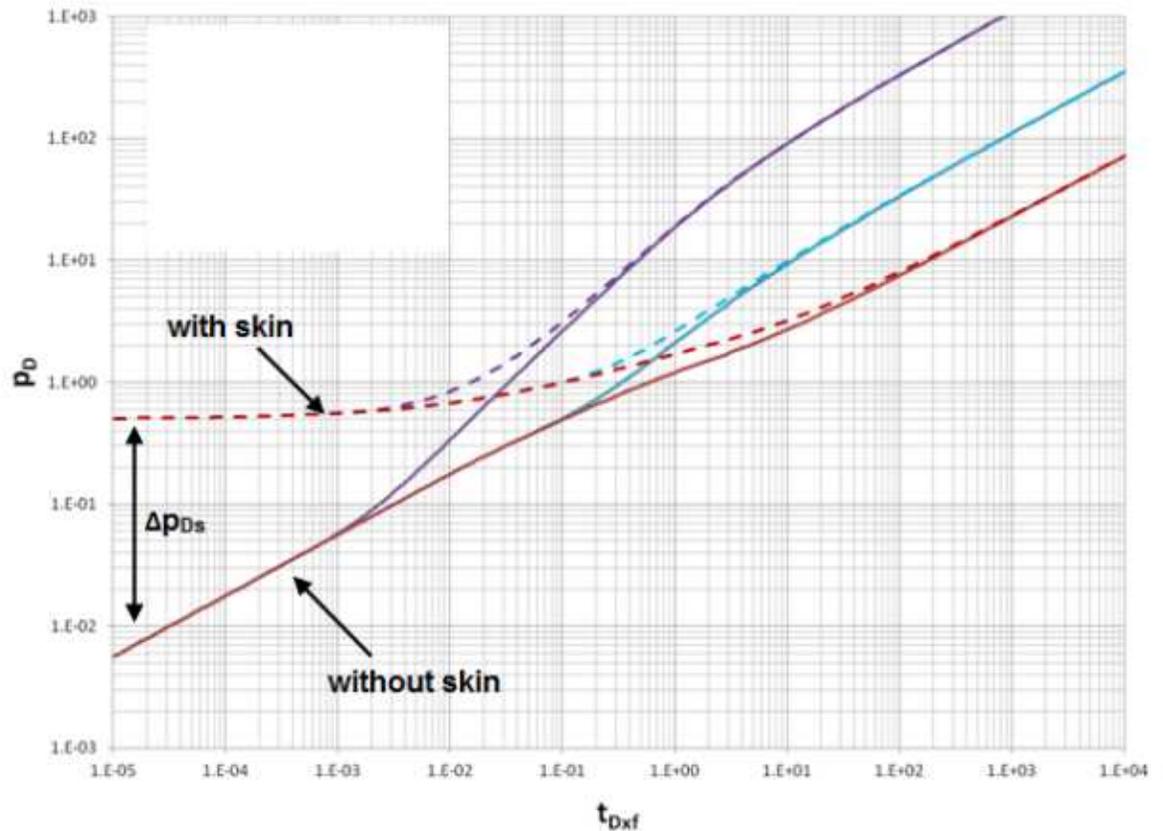


The square root derivative has also been introduced for the compound linear typecurve, and simply rotates the DER typecurve, resulting in a flat line during linear flow.



The typecurves presented above are based on an infinite conductivity fracture with no skin. In reality however, it is quite possible to experience a pressure drop caused by flow convergence, or finite conductivity of the hydraulic fractures. The existence of such a skin will change the shape of the data on a log-log plot, and can have a significant effect on typecurve matching if not accounted for properly. The figure below shows the effect of skin on the typecurve shape:

Figure 8



The dimensionless pressure drop illustrated in Figure 8 can be expressed as a total apparent skin using the following equation:

$$s' = \Delta p_{Ds} \times n_f \times \left(\frac{2x_f}{h} \right)$$

The same dimensionless pressure drop can be expressed in terms of an apparent FCD as follows:

$$FCD' = \frac{1}{\Delta p_{Ds}} \times \frac{1}{n_f} \times \left(1 + \frac{h}{x_f} \left(\ln \left(\frac{h}{2r_w} \right) - \frac{\pi}{2} \right) \right)$$

The actual pressure drop due to skin is estimated using the average flow rate of the last five data points ($q_{@ \Delta p_{Ds}}$), and the following equation:

$$\Delta p_s = q_{@ \Delta p_{Ds}} \times \frac{141.2B\mu(\Delta p_{Ds})}{kh}$$

Methodology

Data preparation

The horizontal axis is material balance time (pseudo-time for gas).

Pressure – time

For the Pressure - Time family of typecurves, the vertical axis plots are:

- Normalized pressure
- Semi-log pressure derivative
- Integral derivative
- Square root derivative

Normalized pressure

Oil wells

$$\frac{\Delta p}{q} = \frac{(p_i - p_{wf})}{q}$$

Gas wells

$$\frac{\Delta p_p}{q} = \frac{(p_i - p_{pwf})}{q}$$

Raw data derivative

Oil wells

$$DER = t_c \frac{\partial \left(\frac{\Delta p}{q} \right)'}{\partial (t_c)}$$

Gas wells

$$DER = t_{ca} \frac{\partial \left(\frac{\Delta p_p}{q} \right)'}{\partial (t_{ca})}$$

Derivative

Oil wells

$$t_c \frac{\partial \left(\frac{1}{t_c} \int \left(\frac{\Delta p}{q} \right)' dt \right)}{\partial(t_c)}$$

Gas wells

$$t_{ca} \frac{\partial \left(\frac{1}{t_{ca}} \int \left(\frac{\Delta p_p}{q} \right)' dt \right)}{\partial(t_{ca})}$$

Square-root pressure derivative

Oil wells

$$2\sqrt{t_c} \frac{\partial \left(\frac{\Delta p}{q} \right)'}{\partial(t_c)}$$

Gas wells

$$2\sqrt{t_{ca}} \frac{\partial \left(\frac{\Delta p_p}{q} \right)'}{\partial(t_{ca})}$$

Calculation of parameters

Oil wells

Once a satisfactory match is achieved, the match point is defined as follows:

$$X_{Match} = \frac{t_c}{t_{Dxf}}$$

$$Y_{Match} = \frac{n_f \left(\frac{\Delta p}{q} \right)'}{(p_D)}$$

Using the dimensionless variable definitions:

$$p_D = \frac{\Delta p k h}{141.2 q B \mu}$$

$$t_{Dx_f} = \frac{0.00633 k t}{\phi \mu c_t x_f^2}$$

along with the match point, the following variable can be calculated:

$$k = \frac{141.2 B \mu}{h (Y_{Match})}$$

$$x_f = \sqrt{\frac{0.00633 k}{\phi \mu c_t} (X_{Match})}$$

$$x_s = x_f \times \left(\frac{x_s}{x_f} \right)_{Typecurve}$$

$$L_e = x_s \times n_f$$

Gas wells

Once a satisfactory match is achieved, the match point is defined as follows:

$$X_{Match} = \frac{t_{ca}}{t_{Dx_f}}$$

$$Y_{Match} = \frac{n_f \left(\frac{\Delta p_p}{q} \right)'}{p_D}$$

Using the dimensionless variable definitions:

$$p_D = \frac{\Delta p k h}{141.2 q B \mu}$$

$$t_{Dxf} = \frac{0.00633kt}{\phi\mu c_t x_f^2}$$

along with the match point, the following variable can be calculated:

$$k = \frac{1.417E6T}{h(Y_{Match})}$$

$$x_f = \sqrt{\frac{0.00633k}{\phi\mu c_t} (X_{Match})}$$

$$x_s = x_f \times \left(\frac{x_s}{x_f}\right)_{Typecurve}$$

$$L_e = x_s \times n_f$$

Rate - time

For the Rate - Time family of typecurves, the vertical axis plots are:

- Normalized rate
- Semi-log pressure derivative
- Integral derivative
- Square root derivative

Normalized rate

Oil wells

$$\frac{q}{\Delta p} = \frac{q}{(p_i - p_{wf})}$$

Gas wells

$$\frac{q}{\Delta p_p} = \frac{q}{(p_{pi} - p_{pwf})}$$

Raw data derivative

Oil wells

$$DER = \frac{1}{t_c \frac{\partial \left(\frac{\Delta p}{q} \right)'}{\partial(t_c)}}$$

Gas wells

$$DER = \frac{1}{t_{ca} \frac{\partial \left(\frac{\Delta p_p}{q} \right)'}{\partial(t_{ca})}}$$

Derivative

Oil wells

$$\frac{1}{t_c \frac{\partial \left(\frac{1}{t_c} \int \left(\frac{\Delta p}{q} \right)' dt \right)}{\partial(t_c)}}$$

Gas wells

$$\frac{1}{t_{ca} \frac{\partial \left(\frac{1}{t_{ca}} \int \left(\frac{\Delta p_p}{q} \right)' dt \right)}{\partial(t_{ca})}}$$

Square-root pressure derivative

Oil wells

$$\frac{1}{2\sqrt{t_c} \frac{\partial \left(\frac{\Delta p}{q} \right)'}{\partial(t_c)}}$$

Gas wells

$$\frac{1}{2\sqrt{t_{ca}} \frac{\partial \left(\frac{\Delta p_p}{q} \right)'}{\partial (t_{ca})}}$$

Calculation of parameters

Oil wells

Once a satisfactory match is achieved, the match point is defined as follows:

$$X_{Match} = \frac{t_c}{t_{Dxf}}$$

$$Y_{Match} = \frac{\left(\frac{q}{\Delta p} \right)'}{(n_f q_D)}$$

Using the dimensionless variable definitions:

$$q_D = \frac{1}{p_D}$$

$$t_{Dxf} = \frac{0.00633kt}{\phi \mu c_t x_f^2}$$

along with the match point, the following variable can be calculated:

$$k = \frac{141.2B\mu}{h} \left(Y_{Match} \right)$$

$$x_f = \sqrt{\frac{0.00633k}{\phi \mu c_t} \left(X_{Match} \right)}$$

$$x_s = x_f \times \left(\frac{x_s}{x_f} \right)_{Typecurve}$$

$$L_e = x_s \times n_f$$

Gas wells

Once a satisfactory match is achieved, the match point is defined as follows:

$$X_{Match} = \frac{t_{ca}}{t_{Dxf}}$$

$$Y_{Match} = \frac{\left(\frac{q}{\Delta p_p} \right)'}{n_f q_D}$$

Using the dimensionless variable definitions:

$$q_D = \frac{1}{p_D}$$

$$t_{Dxf} = \frac{0.00633kt}{\phi\mu c_t x_f^2}$$

along with the match point, the following variable can be calculated:

$$k = \frac{1.417E6T}{h} \left(Y_{Match} \right)$$

$$x_f = \sqrt{\frac{0.00633k}{\phi\mu c_t} \left(X_{Match} \right)}$$

$$x_s = x_f \times \left(\frac{x_s}{x_f} \right)_{Typecurve}$$

$$L_e = x_s \times n_f$$

Boundary-dominated flow

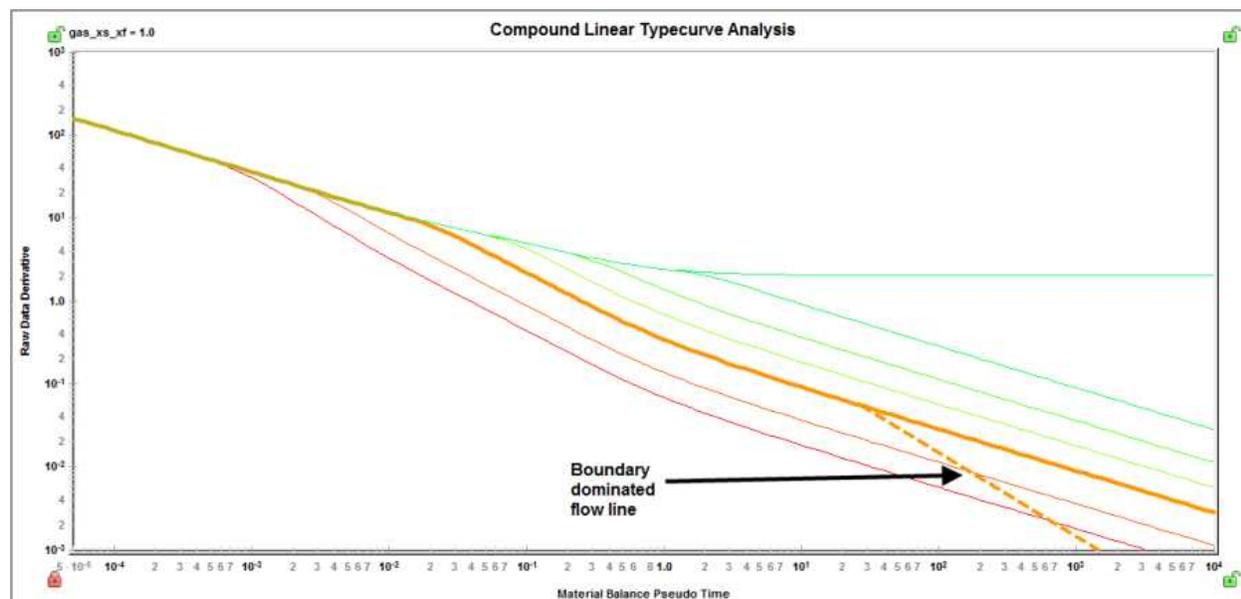
The compound linear typecurves described above were developed for an infinitely large reservoir. Most unconventional reservoirs will, however, experience boundary-dominated flow eventually. The time at which this happens will generally depend on well spacing.

Boundary-dominated flow will appear as a straight line with a unit slope on a log-log plot, and can be expressed by the following equation using the raw data derivative:

$$RawData\ DER = \left(2\pi \frac{x_f^2}{X_e Y_e} \right) t_{Dxf}$$

This boundary-dominated flow line is represented by a dotted line intersecting the compound linear flow curve, and will be displayed only when a valid area or reservoir length has been entered.

Figure 9



Fetkovich typecurve theory

Fetkovich recognized that decline curve analysis was only applicable during the depletion period (ie. when production is in boundary-dominated flow), and thus the early production life of a well (ie. when production is in transient flow) was not analyzable by the conventional decline curve

methods. Fetkovich used analytical flow equations to generate typecurves for transient flow, which he combined with the empirical decline curve equations originally documented by J.J. Arps. For more information, see [decline analysis theory](#). In doing so, Fetkovich presented a new set of typecurves that extended the Arps typecurves into the transient flow region.

Typecurve derivation

The Fetkovich typecurve graph consists of the following two sections which have been blended to be continuous and thereby encompass the entire production life, from transient to boundary-dominated flow:

- Early-time curves (left-side)
- Late-time curves (right-side)

The early-time portion is derived from transient flow equations which come from the field of well-test analysis, whereas the late-time portion consists simply of the Arps typecurve. The common link between the two sections is the exponential decline curve. It is the limiting behavior of all the transient curves when they reach boundary-dominated flow. It is also the first curve in the Arps family of hyperbolic decline curves ($b = 0$).

Early-time curves

The reservoir that Fetkovich considered in developing the transient flow equations was that of a closed circular reservoir with a well at the center, producing at a constant sandface flowing pressure. The mathematical model has the same standard assumptions as those used when describing reservoirs in the field of well-testing:

- Homogeneous reservoir
- Constant thickness
- Single-phase fluid of constant and small compressibility
- No-flow outer boundary
- Constant flowing pressure at the wellbore

The problem was originally solved by Van Everdingen and Hurst (1949).

The transient portion of the flow rate equations can be represented by numerical curve fit equations (Edwardson et al., 1961). These are given by:

$$q_D = \frac{26.7544 + 43.5537 t_D^{0.5} + 13.3818 t_D + 0.492949 t_D^{1.5}}{47.421 t_D^{0.5} + 35.5372 t_D + 2.60967 t_D^{1.5}}, \quad t_D < 200$$

$$q_D = \frac{3.90086 + 2.02623 \cdot t_D \cdot (\ln t_D - 1)}{t_D \cdot (\ln t_D)^2}, t_D > 200$$

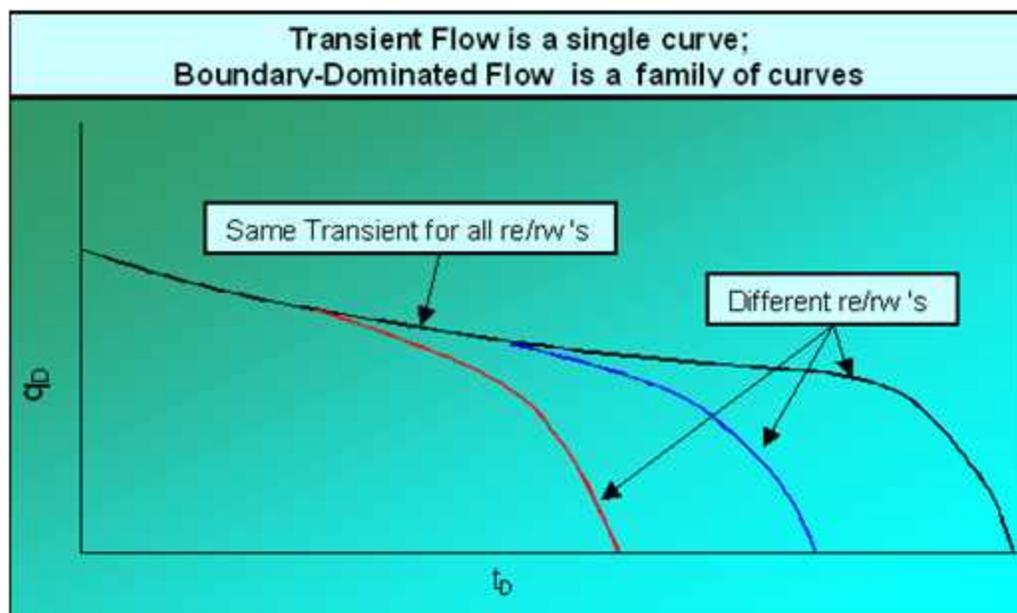
Note: These definitions of dimensionless time (t_D) and dimensionless rate (q_D) are based on well-test applications. For the definitions of these variables as they apply to decline curve analysis, see [late-time curves](#).

Fetkovich modified the definitions of dimensionless rate and time as follows:

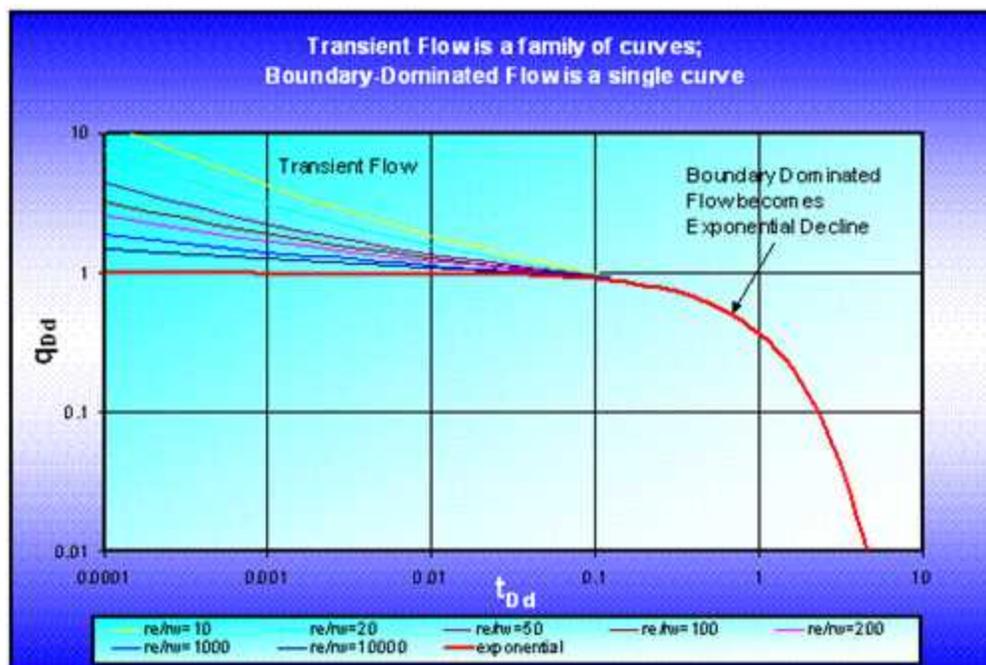
$$q_{Dd} = q_D \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{1}{2} \right]$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2} \left[\left(\frac{r_e}{r_{wa}} \right)^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{1}{2} \right]}$$

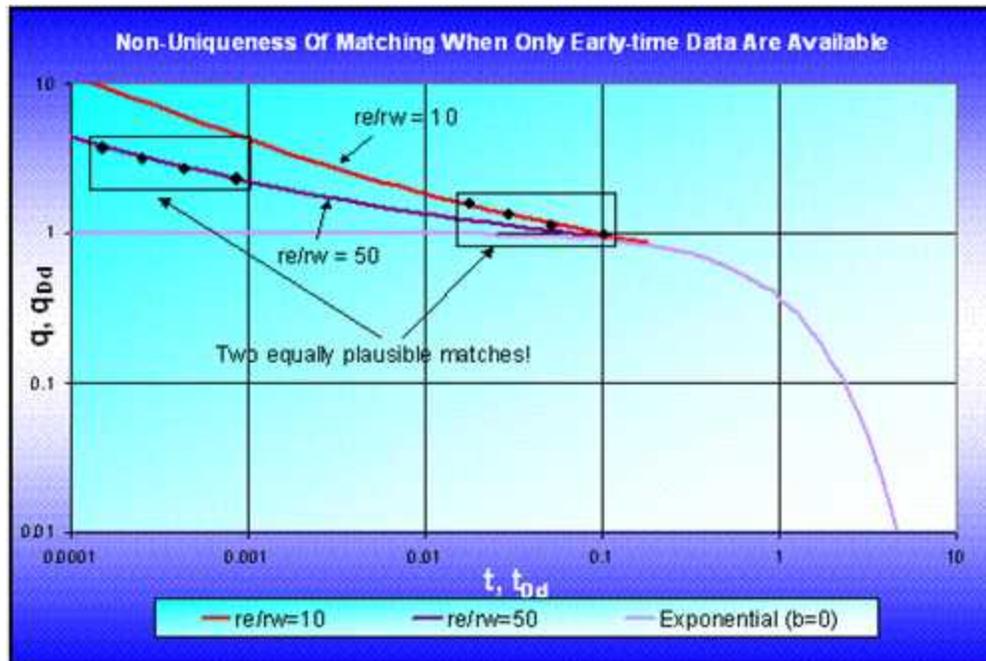
The early-time behavior of the solution to the reservoir problem (transient flow) is the basis of transient well-test analysis, and represents the condition when the reservoir is infinite-acting; when the boundary has not been felt. Obviously transient flow is, by definition, independent of reservoir size; and this would be clearly evident if the flow rate were plotted as dimensionless rate vs. dimensionless time. As shown below, all reservoirs would follow the same curve at early-time and would only deviate at later times, when the reservoir boundary is felt. As the reservoir size increases, transient flow lasts longer, and the deviation to boundary-dominated flow occurs later.



If the same curves were re-plotted on different axes, the shapes would vary significantly. A particularly useful format is to plot dimensionless decline time (t_{Dd}) on the x-axis, and dimensionless decline rate (q_{Dd}) on the y-axis (see the sub-section [late-time curves](#) for definitions of dimensionless decline rate and time). This merges all of the late-time branches into a single curve, because the variable dimensionless reservoir size (r_e/r_w) is now incorporated into the axes. As a result however, the transient data, instead of forming a single line, now becomes a family of lines, with dimensionless reservoir size as a variable as seen below: (Note that this figure represents the early-time portion of the collective Fetkovich typecurves.)



The above figure shows that for all sizes of reservoirs, when transient flow ends, the boundary-dominated flow can be represented by an exponential decline. A well producing at constant pressure will follow one of these curves. One reason for the success of Fetkovich typecurves is that most oil wells are produced at wide-open conditions (ie. at the lowest possible constant pressure). In addition, the above early-time plot gives the impression that by matching the early-time data on one of these curves, it is possible to identify the dimensionless reservoir size. Hence by implication, if the wellbore radius were known, the reservoir size could be determined. However this is a false impression which occurs because of the axes used for plotting. Keep in mind at all times, that the early-time curves represent transient flow, and by definition, the reservoir size cannot be determined from this data alone. If the only data available were in the early-time regime, a unique match could not be obtained. What appears as a possible match on one dimensionless reservoir size curve will also match another dimensionless reservoir size curve at a different location (note that the curves extend to earlier times). An example of a non-unique match of transient data is shown below.



It is only when the production data extends into the boundary-dominated flow region that the different dimensionless reservoir size branches can be used to determine the actual reservoir size. Matching of the data to the typecurves becomes much more unique. Matching of the late-time data gives an indication of the reserves, which in turn is a direct function of the reservoir size. With the knowledge of reservoir size and the match of the transient data, the dimensionless reservoir size parameter can then be used to calculate the effective wellbore radius (r_{we}), from which the skin factor (s) can be obtained using the following equation:

$$r_{we} = r_w e^{-s}$$

Late-Time Curves

The boundary-dominated equations, which are used when dimensionless decline time exceeds 0.3, are obtained from the Arps decline equations. The dimensionless quantities used in the Arps dimensionless decline curve are defined differently from those used in the well-test literature. This section will relate the two sets of dimensionless definitions.

In the well-testing domain, dimensionless rate and dimensionless time are defined as follows:

$$q_D = \frac{141.2 q \mu B}{k h (p_i - p_{wf})}$$

and:

$$t_D = \frac{0.00633 k t}{\phi \mu c_t r_w^2}$$

Fetkovich used van Everdingen and Hurst's solution (1949) to show that during boundary-dominated flow (i.e. when the reservoir boundary has been felt and the reservoir is in depletion), the dimensionless flow rate can be expressed as an exponential function of dimensionless time and dimensionless reservoir size. This equation can be written in terms of the Arps dimensionless exponential decline equation, which is defined as follows:

$$q_{Dd} = e^{-t_{Dd}}$$

where:

$$q_{Dd} = q_D \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{1}{2} \right]$$

and:

$$t_{Dd} = \frac{t_D}{\frac{1}{2} \left[\left(\frac{r_e}{r_{wa}} \right)^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{1}{2} \right]}$$

Using the definitions of dimensionless decline rate and dimensionless decline time in combination with the exponential decline equation, it can be shown that the exponential decline rate (a) is given by:

$$a = \frac{\frac{0.00633 k}{\phi \mu c_t r_w^2}}{\frac{1}{2} \left[\left(\frac{r_e}{r_{wa}} \right)^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{1}{2} \right]}$$

Thus, Fetkovich has demonstrated that Arps' empirical exponential decline curve has a solid theoretical basis, as the late-time solution to the "constant wellbore flowing pressure" case. From the above equations, the decline coefficient (a) is seen to be a function of rock and fluid properties as well as drainage size, and is independent of the wellbore flowing pressure (for slightly compressible fluids).

The constant q_i for use in the exponential decline equation at $t = 0$, ($q_{Dd} = 1$) can be calculated from:

$$q = q_i = \frac{k h(p_i - p_{wf})}{141.2 \mu B \left[\ln\left(\frac{r_g}{r_{wa}}\right) - \frac{1}{2} \right]}$$

If the hyperbolic decline equation:

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

is presented in graphical form it can be seen to encompass the whole range of conditions from exponential decline ($b = 0$) to harmonic decline ($b = 1$), where each value of initial rate (q_i), initial nominal decline rate (a_i), and decline exponent (b) will produce its own unique curve. Fetkovich generalized these curves by making the equation dimensionless.

He defined a dimensionless decline rate as:

$$q_{Dd} = \frac{q(t)}{q_i}$$

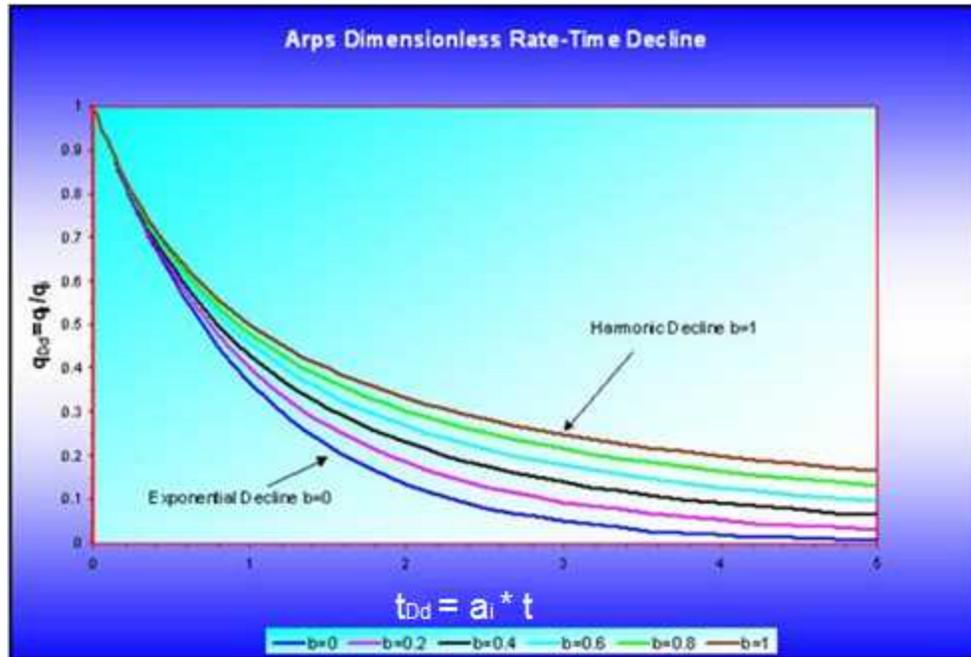
and a dimensionless decline time as:

$$t_{Dd} = a_i t$$

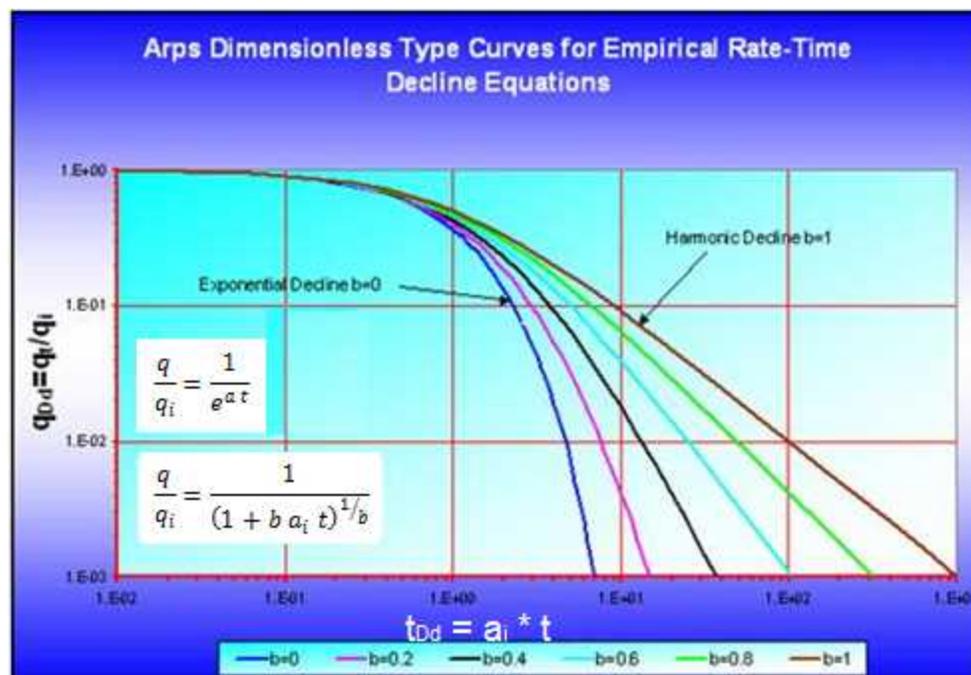
The resulting dimensionless equation is:

$$q_{Dd} = \frac{1}{(1 + b t_{Dd})^{\frac{1}{b}}}$$

If this equation is plotted using dimensionless decline time and rate as the axes, a unique set of curves is obtained that represents all decline conditions for all wells. Notice that the obtained curves are independent of initial nominal decline rate and initial flow rate when plotted on these dimensionless coordinates.



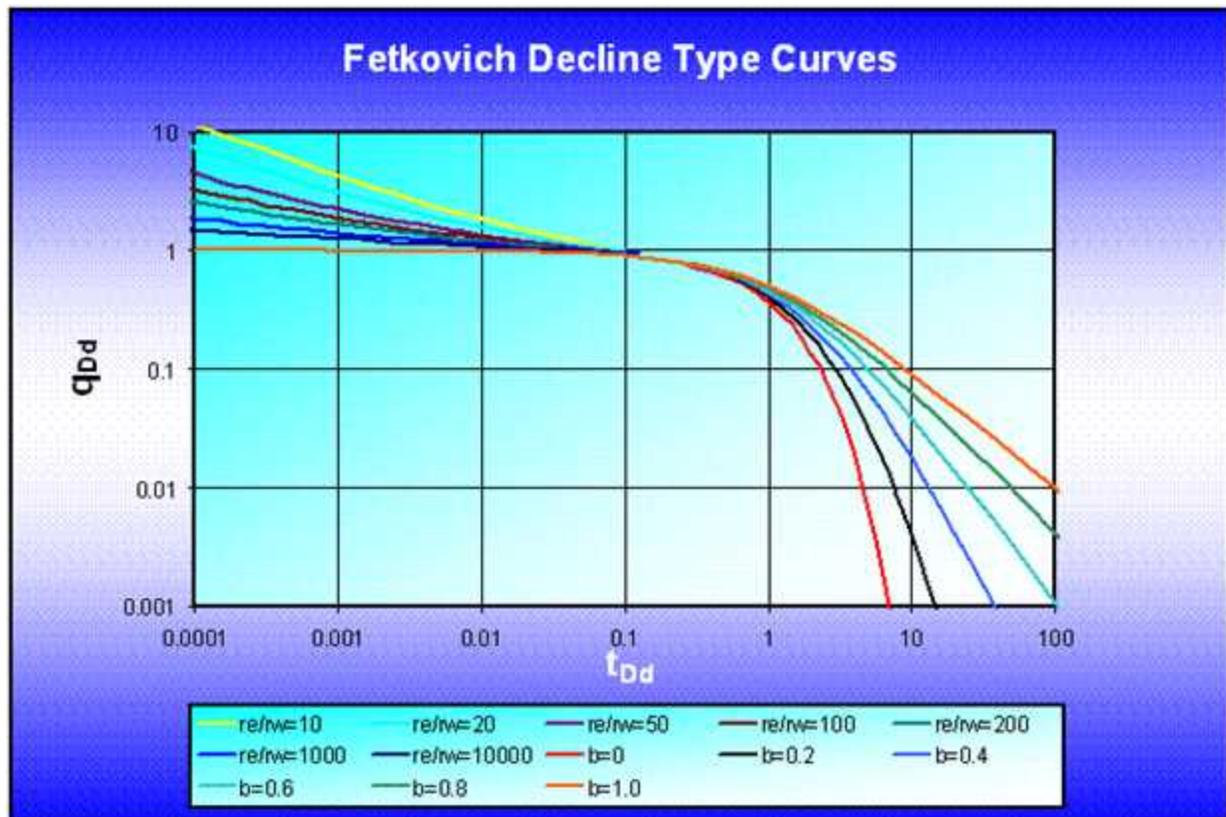
When these dimensionless curves are plotted on log-log scales as shown below, they are called typecurves, and can be used for graphical analysis of actual production data. (Note that these typecurves represent the late-time portion of the collective Fetkovich typecurves.)



Typecurves can be used for graphical interpretation of a well's production decline. The production rate of the well is plotted on transparent graph paper of the same scale as the typecurve, and overlain on the typecurve (keeping the axes parallel). The data plot is moved over the typecurves until the best fitting curve is determined. This gives the value of the decline exponent. The values of initial flow rate and initial nominal decline rate are determined by selecting any point on the data plot and the corresponding point on the typecurve. The value of initial flow rate is obtained by dividing the "match point" values off the data plot and the typecurve, $q_i = (q_t / q_{Dd})_{match}$. The value of initial nominal decline rate is obtained by dividing the "match point" values off the typecurve and the data plot, $a_i = (t_{Dd} / t)_{match}$. The production forecast is obtained by tracing the matched curve onto the data plot and extrapolating.

Fetkovich typecurves – combined early and late-time portions

Combining the Fetkovich transient curves (early-time portion) with the Arps decline curves (late-time portion), and blending them where the two sets of curves meet results in the Fetkovich decline typecurves, shown below.



From the Fetkovich typecurve plot it is evident that the transition from transient to depletion behavior occurs at a dimensionless time of 0.1. Until the dimensionless time exceeds 0.1, it is impossible to know the type of decline that ultimately develops.

Fetkovich noted that sometimes the hyperbolic decline coefficient 'b', as determined using the Arps decline curves, was larger than 1 (it is normally expected to be between 0 and 1). The explanation that he postulated for this was that the data being analyzed was still in the transient regime, and had not reached the boundary-dominated regime. If data still in the transient flow regime is forced to match a hyperbolic decline, then b-values larger than 1 will result.

Typecurve calculations

Typecurve calculations are described below.

Rate – time typecurves

The actual rate-time data are plotted on a log-log scale of the same size as the typecurves. This plot is called the "data plot". Any convenient units can be used for rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates; especially when transient data are analyzed. However, for very noisy and cyclic data, Fetkovich suggests 6-month averaging of the data. In addition, a log-log plot of the cumulative production data vs. time, if matched simultaneously with the rate data, should help in achieving a more unique match of the data with the typecurves.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. The rate and the cumulative data should both fit the same corresponding typecurve. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and its " r_e/r_{wa} " and "b" values are noted.

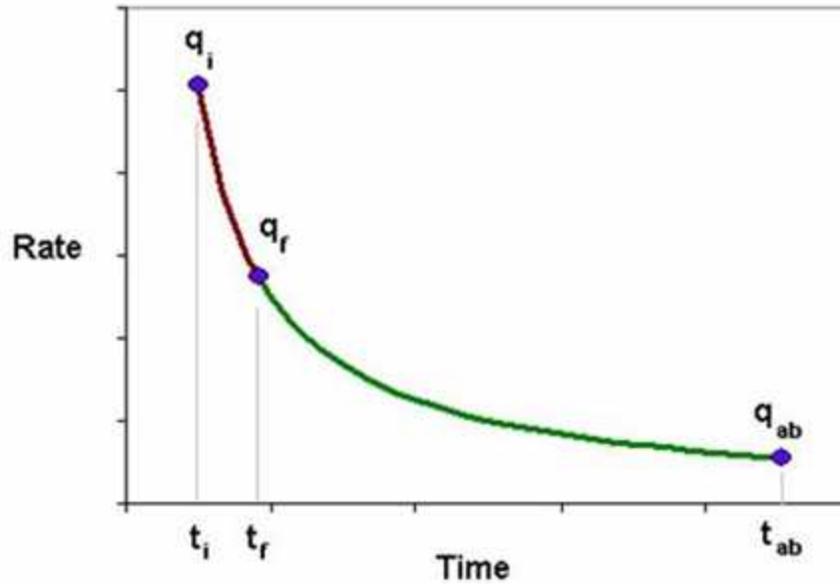
To make a forecast, the selected typecurve is traced on to the data plot, and extrapolated beyond the last data points. The future rate is then read from the data plot off the traced typecurve.

Typecurve analysis is done by selecting a match point and reading its co-ordinates off the data plot (q and t)_{match}, and off the typecurve plot (q_{Dd} and t_{Dd})_{match}. At the same time the stem values (" r_e/r_{wa} " and "b") of the matching curve are noted.

From the right-hand-set of typecurves, the following decline curve parameters can be obtained:

$$q_i = \frac{q(\text{match})}{q_{Dd}(\text{match})}$$

$$a_i = \frac{t_{Dd}(match)}{t(match)}$$



The subscript 'f' denotes conditions at the beginning of the forecast period.

With these, we can now calculate the expected ultimate recovery.

Exponential

$$EUR = Q_f + \frac{q_f - q_{ab}}{a}$$

$$q_f = q_i e^{(-a t_f)}$$

Hyperbolic

$$EUR = Q_f + \frac{q_i^b}{(1-b)a_i} \left(q_i^{1-b} (1 + b a_i t_f)^{\left(1-\frac{1}{b}\right)} - q_{ab}^{1-b} \right)$$

$$q_f = q_i (1 + b a_i t_f)^{-\frac{1}{b}} \text{ (b not equal to 0)}$$

$$a_f = a_i(1 + b a_i t_f)^{-1}$$

Harmonic

$$EUR = Q_f + \frac{q_i}{a_i} \left(\frac{q_i}{q_{ab}(1 + a_i t_f)} \right)$$

$$q_f = q_i(1 + a_i t_f)^{-1}$$

$$a_f = a_i(1 + a_i t_f)^{-1}$$

Now, we can estimate fluid-in-place and drainage area.

Oil

$$N = \frac{EUR}{c_t(p_i - p_{wf})} \text{ (Mbbls)}$$

$$A = \frac{N B_o}{\phi h S_o (43560)} \text{ (Acres)}$$

Gas

$$G = \frac{EUR * p_i Z_{wf}}{p_i Z_{wf} - p_{wf} Z_i} \text{ (bcf)}$$

$$A = \frac{Z_i T p_{sc} G}{\phi h S_g p_i T_{sc} (43560)} \text{ (Acres)}$$

From the left-hand set of typecurves, the reservoir parameters can be obtained if initial reservoir pressure, wellbore flowing pressure, net pay, total compressibility, and wellbore radius are known.

$$\left(\frac{r_e}{r_{wa}}\right)_{match} = \text{value of typecurve stem (left-hand set of curves)}$$

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = q \left(\frac{141.2 B \mu}{k h (p_i - p_{wff})} \right) \left(\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right)$$

$$k = \left(\frac{q}{q_{Dd}} \right)_{match} \left(\frac{141.2 B \mu}{h (p_i - p_{wff})} \right) \left(\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right)$$

Permeability can be also obtained by rearranging the definition of dimensionless decline rate as follows:

$$q_{Dd} = q \left(\frac{1.417 * 10^6 T}{k h (p_{pi} - p_{pwf})} \right) \left(\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right)$$

$$k = \left(\frac{q}{q_{Dd}} \right)_{match} \left(\frac{1.417 * 10^6 T}{h (p_{pi} - p_{pwf})} \right) \left(\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right)$$

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633 k t}{\frac{1}{2} \phi \mu c_t r_{wa}^2 \left(\left(\frac{r_e}{r_{wa}} \right)_{match}^2 - 1 \right) \left(\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right)}$$

$$r_{wa} = \sqrt{\left(\frac{t}{t_{Dd}}\right)_{match} \frac{0.00633 k}{\phi \mu c_t \frac{1}{2} \left(\left(\frac{r_e}{r_{wa}}\right)^2 - 1 \right) \left(\ln \left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} \right)}}$$

Skin factor is calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

Cumulative – time typecurves

Production data is often quite noisy, and thus difficult to analyze. To reduce the effect of this noise, the cumulative production can be used. It is a smoother curve than production data and can make the analysis more reliable. Fraim and Lee developed cumulative typecurves of dimensionless cumulative decline production (Q_{Dd}) vs. dimensionless decline time (t_{Dd}); where the dimensionless cumulative decline production is defined as the ratio of cumulative production to the ultimate movable fluid.

Oil

$$Q_{Dd} = \frac{B N_p 1.787}{c_t h \phi (r_e^2 - r_w^2) (p_i - p_{wf})} = \frac{N_p}{N_{p,n}}$$

Gas

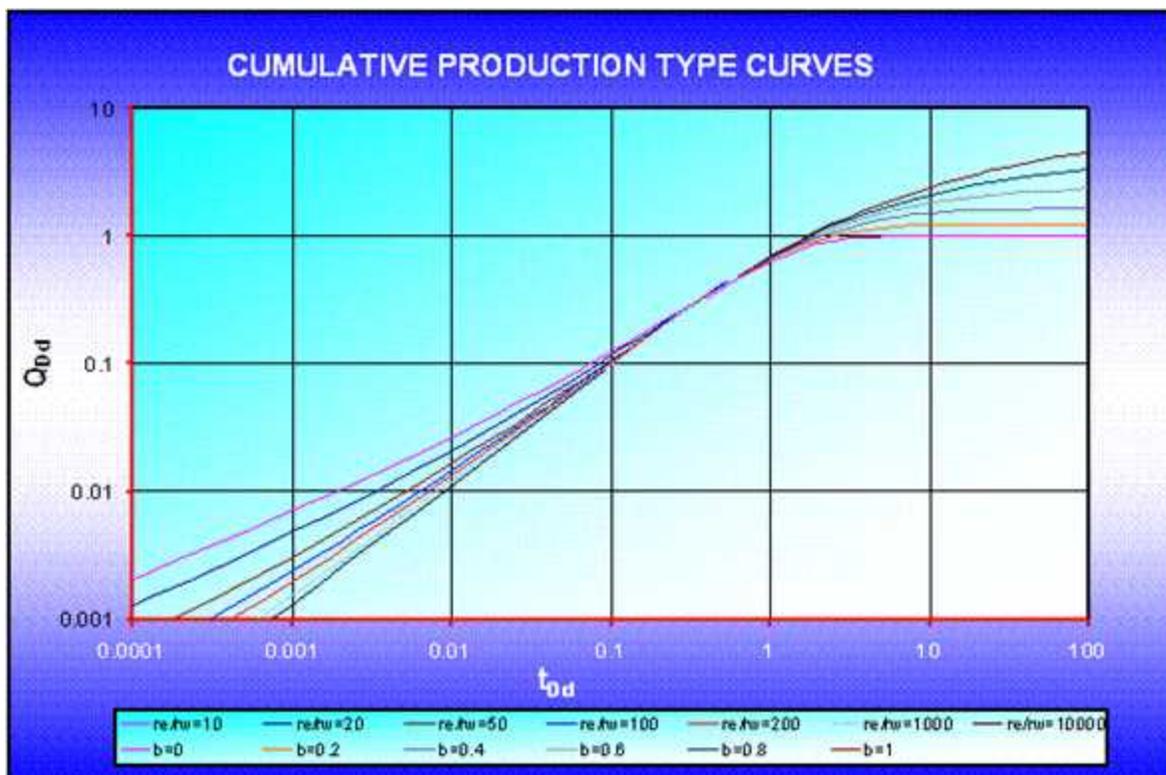
$$Q_{Dd} = \frac{637.8 p_{sc} T G_p}{T_{sc} h \phi \bar{\mu} c_t (r_e^2 - r_w^2) (\Psi_i - \Psi_{wf})} = \frac{G_p}{G_{p,n}} S$$

where (oil and gas):

$$Q_{Dd} = \int_0^{t_{Dd}} q_{Dd} dt_{Dd} = \frac{\int_0^{t_{Dd}} q_D dt_D}{\frac{1}{2} \left[\left(\frac{r_e}{r_w}\right)^2 - 1 \right]} = \frac{Q_D}{\frac{1}{2} \left[\left(\frac{r_e}{r_w}\right)^2 - 1 \right]}$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2} \left[\left(\frac{r_e}{r_w} \right)^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_w} \right) - \frac{3}{4} \right]}$$

From the Fetkovich typecurves, the rate can be integrated to determine the cumulative production, and plotted in typecurve format.



Cumulative graphs show that, at dimensionless decline time (t_{Dd}) = 100, harmonic decline leads to five times more cumulative production as compared to exponential decline.

The authors indicated that the dimensionless decline time-function used for the cumulative plots above has 3/4 in the denominator, whereas in the Fetkovich type curves, the dimensionless decline time-function has 1/2 in the denominator. The factor 3/4 appears in the inflow equation when the drawdown is referenced to the average reservoir pressure, and the factor 1/2 appears when the reference is the initial pressure at reservoir radius (r_e). Fetkovich tried using 1/2, 5/8, and 3/4; and found that using 1/2 reduced the discontinuity between the transient stems and the hyperbolic stems.

Typecurve equations

Typecurve equations are described below.

Cumulative typecurves

Fraim and Lee (1987), and Spivey et al. (1992) provide detailed equations for generating the transient and the boundary-dominated stems of the cumulative production typecurves. Transient flow rate and cumulative production are reported as functions of time by Edwardson et al. (1961). The cumulative values are given by:

$$Q_D = \frac{1.12838 t_D^{0.5} + 1.19328 t_D + 0.269872 t_D^{1.5} + 0.00855294 t_D^2}{1 + 0.616599 t_D^{0.5} + 0.0413008 t_D}, t_D < 200$$

$$Q_D = \frac{-4.29881 + 2.02566 t_D}{(\ln t_D)}, t_D > 200$$

The well test-based dimensionless cumulative production (Q_D) and dimensionless time (t_D) are converted to decline-based dimensionless cumulative production (Q_{Dd}) and decline-based dimensionless time (t_{Dd}) by:

$$Q_{Dd} = \int_0^{t_{Dd}} q_{Dd} t_{Dd} = \frac{\int_0^{t_D} q_D t_D}{\frac{1}{2} \left[\left(\frac{r_e}{r_w} \right)^2 - 1 \right]} = \frac{Q_D}{\frac{1}{2} \left[\left(\frac{r_e}{r_w} \right)^2 - 1 \right]}$$

$$t_{Dd} = \frac{t_D}{\frac{1}{2} \left[\left(\frac{r_e}{r_w} \right)^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_w} \right) - \frac{3}{4} \right]}$$

The transition from transient equations to boundary-dominated flow equations for cumulative production occurs at $t_{Dd} = 0.6$.

Boundary-dominated flow is obtained from the following equations:

Exponential

$$Q_{Dd} = 1 - e^{-t_{Dd}} = 1 - q_{Dd}$$

Hyperbolic

$$Q_{Dd} = \frac{1}{1-b} \left[1 - (1 + b t_{Dd})^{1-\frac{1}{b}} \right] = \frac{1 - q_{Dd}^{1-b}}{1-b}$$

Harmonic

$$Q_{Dd} = \ln(1 + t_{Dd}) = \ln\left(\frac{1}{q_{Dd}}\right)$$

Cumulative / derivative typecurves

Spivey et al. showed that typecurves of cumulative production can be combined with their (semi-log) derivative to give a set of typecurves that uses only cumulative production data and not rate. Because cumulative production tends to be much smoother than the original rate data, these plots tend to have less scatter than the traditional Fetkovich typecurves. The derivative typecurves are obtained from:

$$\text{Derivative} = \frac{d(Q)}{d(\ln t)}$$

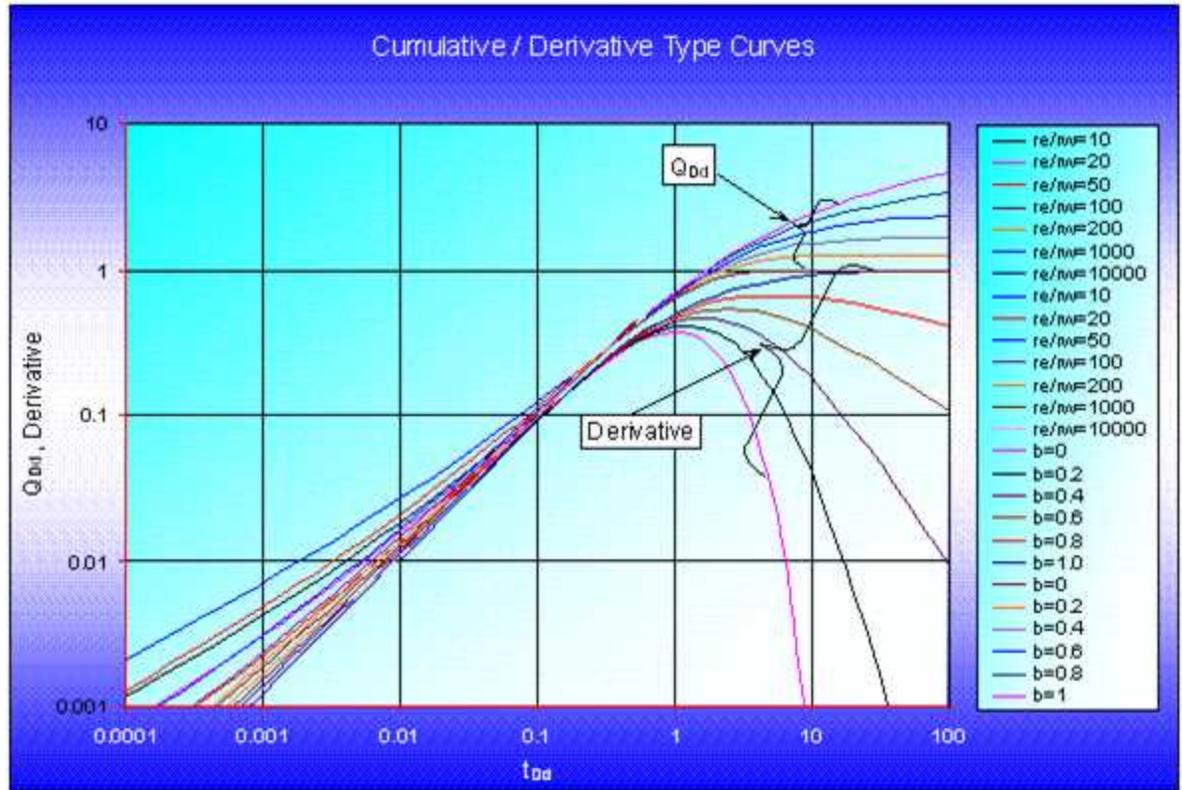
This can be shown to be mathematically equivalent to:

$$\text{Derivative} = q * t$$

and, in dimensionless form:

$$\text{Derivative} = q_{Dd} * t_{Dd}$$

Simply multiplying the rate by time gives the semi-log derivative of cumulative production. The typecurve plot of cumulative production and its derivative are shown in the following plot.



Rate-integral typecurves

Blasingame et al. (1989) introduced the concept of integral typecurves in the field of well testing. Spivey et al. (1992) extended the concept to decline curve analysis, and they state that as production data is usually very noisy, plotting a rate-integral or cumulative production should reduce the noise and make the data much more analyzable. The rate-integral is related to the cumulative production, and is defined as:

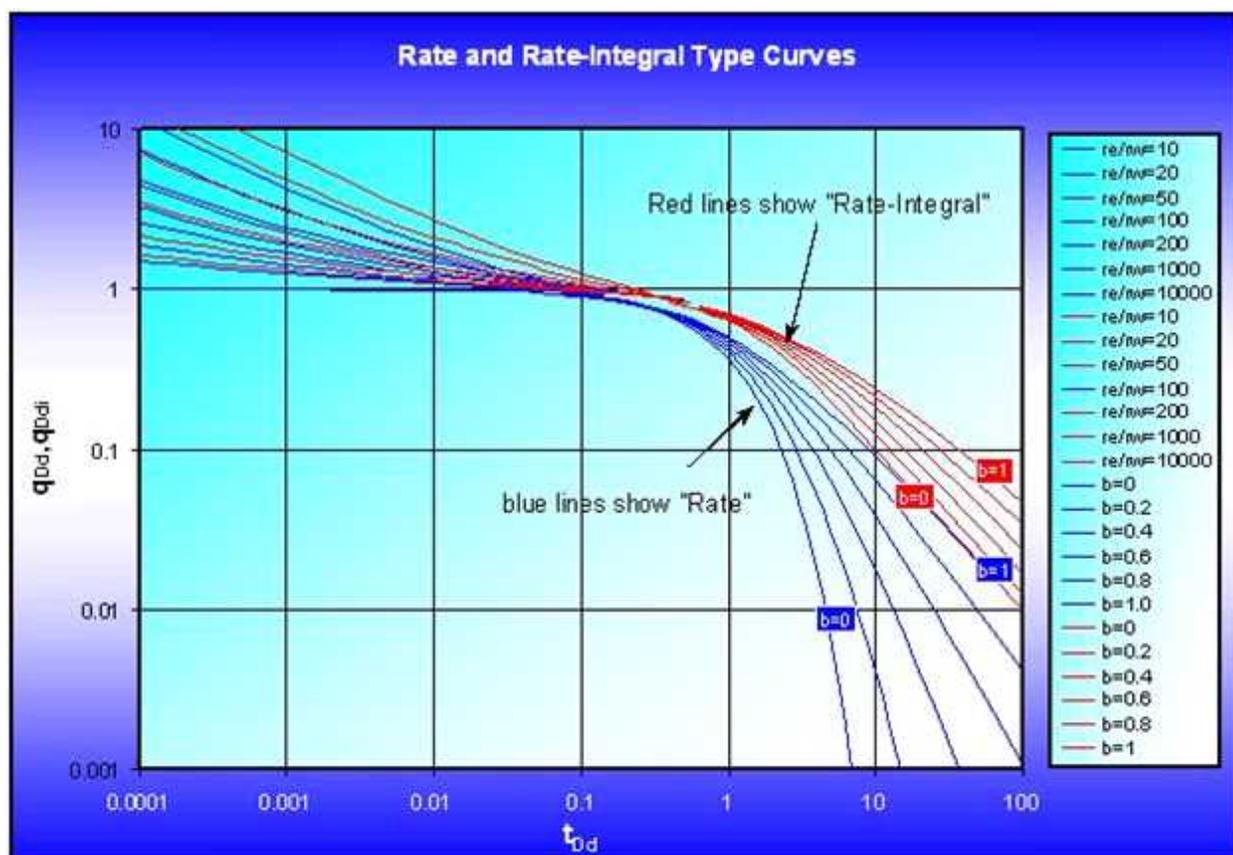
$$q_{integral} = \frac{Q}{t}$$

and, in dimensionless form:

$$q_{Dd,integral} = \frac{Q_{Dd}}{t_{Dd}}$$

The rate-integral is obtained by dividing the cumulative production by the time of flow, as seen in the equations above. The direct physical interpretation of the rate-integral is the average pro-

duction rate, from the beginning of production to the current time. The relationship between rate and rate-integral is shown in the following diagram:



It is seen above that the rate and the rate-integral have very similar characteristics. The advantage of the rate-integral is that it tends to be smoother and less noisy than the rate data. This is consistent with the fact that the rate-integral is essentially a time-dependent average rate, and like all averaging, is less noisy than the original data.

Matching equations (variable flowing pressure)

Matching equations are described below.

Oil

The Fetkovich typecurve matching equations can be extended for use with production at variable flowing pressure. Instead of simply plotting production rate, normalized rate ($q / \Delta p$) is plotted.

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{141.2 q B \mu}{k h \Delta p} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

$$k = \frac{141.2 B \mu}{h} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_{Dd}} \right]_{match} \left[\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right]$$

where $q / \Delta p$ and q_{Dd} are read off the raw data and typecurve graphs at a selected match point.

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633 k t}{\frac{1}{2} \phi \mu c_t r_{wa}^2 \left[\left(\frac{r_e}{r_{wa}} \right)^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]}$$

$$r_{wa} = \sqrt{\left(\frac{t}{t_{Dd}} \right)_{match} \frac{0.00633 k}{\frac{1}{2} \phi \mu c_t \left[\left(\frac{r_e}{r_{wa}} \right)_{match}^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right]}}$$

Finally, skin factor can be calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

For exponential, hyperbolic and harmonic, expected ultimate recovery is calculated as follows:

Exponential

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p} \right)_f (\Delta p)_{forecast} - q_{ab}}{a}$$

$$\left(\frac{q}{\Delta p} \right)_f = \left(\frac{q}{\Delta p} \right)_i e^{(-a_i t_f)}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}}\right]_{match}$$

$$a = \left(\frac{t_{Dd}}{t}\right)_{match}$$

It is assumed that the flowing pressure is constant during the forecast period, and this constant flowing pressure $(p_{wf})_{forecast}$ should be entered for analysis.

Hyperbolic

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p}\right)_f^b (\Delta p)_{forecast}^b}{(1-b)a_f} \left[\left(\frac{q}{\Delta p}\right)_f^{1-b} (\Delta p)_{forecast}^{1-b} - q_{ab}^{1-b} \right]$$

$$\left(\frac{q}{\Delta p}\right)_f = \left(\frac{q}{\Delta p}\right)_i (1 + b a_i t_f)^{-\frac{1}{b}}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}}\right]_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

$$a_f = a_i (1 + b a_i t_f)^{-1}$$

Harmonic

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p}\right)_f (\Delta p)_{forecast}}{a_f} \ln \left[\frac{\left(\frac{q}{\Delta p}\right)_f (\Delta p)_{forecast}}{q_{ab}} \right]$$

$$\left(\frac{q}{\Delta p}\right)_f = \left(\frac{q}{\Delta p}\right)_i (1 + a_i t_f)^{-1}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}} \right]_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

$$a_f = a_i (1 + a_i t_f)^{-1}$$

Gas

Permeability is obtained by rearranging the definition of dimensionless decline rate:

$$q_{Dd} = \frac{1.417 * 10^6 T}{k h \Delta p_p} \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]$$

$$k = \frac{1.417 * 10^6 T}{h} \left[\frac{\left(\frac{q}{\Delta p_p}\right)}{q_{Dd}} \right]_{match} \left[\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right]$$

Where $q / \Delta p_p$ and q_{Dd} are read off the raw data and typecurve graphs at a selected match point.

Solve for apparent wellbore radius from the definition of dimensionless decline time:

$$t_{Dd} = \frac{0.00633 k t}{\frac{1}{2} \phi \mu c_t r_{wa}^2 \left[\left(\frac{r_e}{r_{wa}} \right)^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_{wa}} \right) - \frac{3}{4} \right]}$$

$$r_{wa} = \sqrt{\left(\frac{t}{t_{Dd}} \right)_{match} \frac{0.00633 k}{\frac{1}{2} \phi \mu c_t \left[\left(\frac{r_e}{r_{wa}} \right)_{match}^2 - 1 \right] \left[\ln \left(\frac{r_e}{r_{wa}} \right)_{match} - \frac{3}{4} \right]}}$$

Finally, skin factor can be calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

For exponential, hyperbolic and harmonic, expected ultimate recovery is calculated as follows:

Exponential

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p_p} \right)_f (\Delta p_p)_{forecast} - q_{ab}}{a_i}$$

$$\left(\frac{q}{\Delta p_p} \right)_f = \left(\frac{q}{\Delta p_p} \right)_i e^{(-a_i t_f)}$$

$$\left(\frac{q}{\Delta p} \right)_i = \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_{Dd}} \right]_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t} \right)_{match}$$

It is assumed that the flowing pressure is constant during the forecast period, and this constant flowing pressure $(p_{wf})_{forecast}$ should be entered for analysis.

Hyperbolic

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p_p}\right)_f^b (\Delta p_p)_{forecast}^b}{(1-b)a_f} \left[\left(\frac{q}{\Delta p_p}\right)_f^{1-b} (\Delta p_p)_{forecast}^{1-b} - q_{ab}^{1-b} \right]$$

$$\left(\frac{q}{\Delta p_p}\right)_f = \left(\frac{q}{\Delta p_p}\right)_i (1 + b a_i t_f)^{-\frac{1}{b}}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left[\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}} \right]_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

$$a_f = a_i (1 + b a_i t_f)^{-1}$$

Harmonic

$$\left(\frac{q}{\Delta p}\right)_f = \left(\frac{q}{\Delta p}\right)_i (1 + a_i t_f)^{-1}$$

$$EUR = Q_f + \frac{\left(\frac{q}{\Delta p_p}\right)_f (\Delta p_p)_{forecast}}{a_f} \ln \left[\frac{\left(\frac{q}{\Delta p_p}\right)_f (\Delta p_p)_{forecast}}{q_{ab}} \right]$$

$$\left(\frac{q}{\Delta p_p}\right)_f = \left(\frac{q}{\Delta p_p}\right)_i (1 + a_i t_f)^{-1}$$

$$\left(\frac{q}{\Delta p}\right)_i = \left(\frac{\left(\frac{q}{\Delta p}\right)}{q_{Dd}}\right)_{match}$$

$$a_i = \left(\frac{t_{Dd}}{t}\right)_{match}$$

$$a_f = a_i(1 + a_i t_f)^{-1}$$

Matching equations (normalized data)

In this analysis, normalized rate and normalized cumulative production are used for analysis instead of rate and cumulative production. The same typecurves are used for analysis as for Fetkovich analysis but the equations to calculate reservoir parameters and reserves are slightly different.

Normalized rate and normalized cumulative production are defined as follows:

Normalized rate: oil

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

Normalized rate: gas

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

Normalized cumulative production: oil

$$Q_n = \int_0^t \frac{q}{\Delta p} dt$$

Normalized cumulative production: gas

$$Q_n = \int_0^t \frac{q}{\Delta p_p} dt$$

NPI typecurve theory

The normalized pressure integral (NPI) was initially developed by Blasingame et al. (1989). The objective of the method was to present a robust diagnostic method for drawdowns that did not suffer from noise and data scatter, as is typical of the standard well-test derivative. The solution involves using a pressure integral curve as the base curve for noisy drawdown analysis.

The dimensionless pressure integral is defined as follows:

$$p_{Di} = \frac{1}{t_{DA}} \int_0^{t_{DA}} p_D(t) dt$$

where:

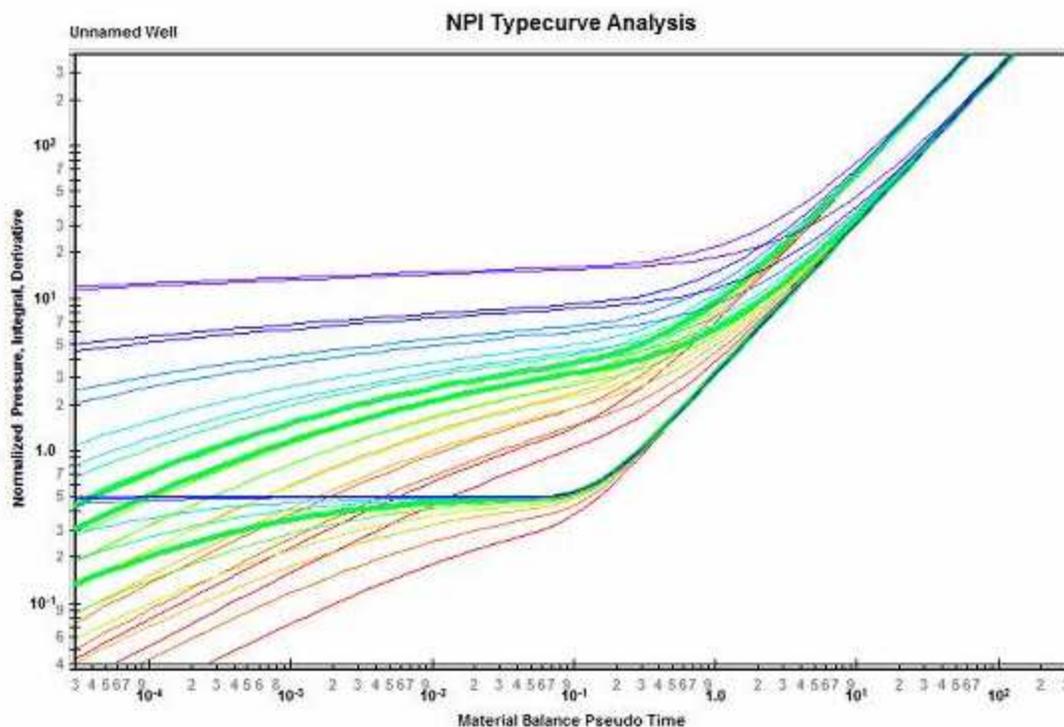
$$p_D = \frac{k h \Delta p}{141.2 q B \mu}$$

Conceptually, the pressure integral is a "cumulative average flowing pressure drop" (see also [rate integral](#)). The distinguishing characteristic of the pressure integral is its smoothness. Thus, it is an ideal base curve for the standard pressure derivative if the raw data contains any degree of noise or scatter.

The dimensionless pressure integral derivative is defined as follows:

$$p_{Did} = t_{DA} \frac{dp_{Di}}{dt_{DA}} = p_D - p_{Di}$$

Below is a graph of the three dimensionless typecurves (that is, p_D , p_{Di} and p_{Did}), representing the solution for a vertical well in the center of a bounded reservoir (circle).



Methodology

Modifications in RTA

The original development of pressure integral typecurves was for pressure transient analysis. However, the theory can be extended to production data analysis (Rate Transient Analysis), using the following concepts:

- Equivalence of constant rate and pressure
- Material balance time

As a production data analysis method, the normalized pressure integral has the advantage of blending seamlessly with transient well-test interpretation. In fact, the diagnostic plot is equivalent to that of an extended drawdown test. The perspective is quite different from decline curves, and provides a useful benchmark for comparison of results.

Data preparation

In normalized pressure integral typecurve analysis, the following three rate functions can be plotted against material balance time.

Normalized pressure

Oil wells

$$\frac{\Delta p}{q}$$

Gas wells

$$\frac{\Delta p_p}{q}$$

Normalized pressure integral

The pressure integral is defined at any point in the producing life of a well, as the average normalized flowing pressure drop at which the well has produced until that moment in time. The normalized pressure integral is defined as follows:

Oil wells

$$\left(\frac{\Delta p}{q}\right)_i = \frac{1}{t_c} \int_0^{t_c} \frac{\Delta p}{q} dt_c$$

Gas wells

$$\left(\frac{\Delta p_p}{q}\right)_i = \frac{1}{t_{ca}} \int_0^{t_{ca}} \frac{\Delta p_p}{q} dt_{ca}$$

Pressure integral derivative

The pressure integral derivative is defined as the semi-logarithmic derivative of the pressure integral function, with respect to material balance time. It is defined as follows:

Oil wells

$$\left(\frac{\Delta p}{q}\right)_{id} = t_c \frac{d\left(\frac{\Delta p}{q}\right)_i}{dt_c}$$

Gas wells

$$\left(\frac{\Delta p_p}{q}\right)_{id} = \frac{t_{ca} d\left(\frac{\Delta p_p}{q}\right)_i}{dt_{ca}}$$

Analysis

The actual normalized pressure, pressure integral, and pressure integral derivative are plotted vs. material balance time data on a log-log scale of the same size as the typecurves. This plot is called the “data plot”. Any convenient units can be used for normalized rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates, especially when transient data are analyzed. Any one of the curves can be used individually but often using more than one curve helps in achieving a more unique match of the data with the typecurves.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. The pressure, pressure integral, and pressure integral derivative data should all fit the same corresponding typecurve. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and its r_e / r_{wa} (r_e / x_f for fractured case) value is noted.

Typecurve analysis is done by selecting a match point, and reading its co-ordinates off the data plot ($\Delta p / q$ and t_{ca})_{match}, and the typecurve plot (p_D and t_{DA})_{match}. At the same time the stem value r_e / r_{wa} (r_e / x_f for fracture typecurves) of the matching curve is noted. To create a forecast, the selected typecurve is traced on to the data plot, and extrapolated. The future rate is read from the data plot, off the traced typecurve.

Given a curve match, the following reservoir parameters can be obtained if net pay, total compressibility, and wellbore radius are known: permeability, skin (or fracture half length, depending on which model is chosen), area, and original fluids-in-place.

Calculation of parameters

Radial typecurves

Oil wells

$$p_D = \frac{k h \Delta p}{141.2 q B \mu}$$

$$t_{DA} = \frac{0.00633 k t_c}{\pi \phi \mu c_t r_e^2}$$

$$k = \frac{141.2 B \mu}{h} \left(\frac{p_D}{\frac{\Delta p}{q}} \right)_{match}$$

$$r_e = \sqrt{\frac{0.00633 k}{\pi \phi \mu c_t} \left(\frac{t_c}{t_{DA}} \right)_{match}}$$

$$r_{wa} = \frac{r_e}{\left(\frac{r_e}{r_{wa}} \right)_{match}}$$

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

$$N = \frac{0.00633}{c_t} \left(\frac{141.2 S_0}{5.615 * 10^3} \right) \left(\frac{p_D}{\frac{\Delta p}{q}} \right)_{match} \left(\frac{t_c}{t_{DA}} \right)_{match} \quad (\text{Mbbbls})$$

Gas wells

$$p_D = \frac{k h \Delta p_p}{1.417 * 10^6 T q}$$

$$t_{DA} = \frac{0.00633 k t_{ca}}{\pi \phi \mu_i c_{ti} r_e^2}$$

$$k = \frac{1.417 * 10^6 T}{h} \left(\frac{p_D}{\frac{\Delta p_p}{q}} \right)_{match}$$

$$r_e = \sqrt{\frac{0.00633 k (t_{ca})}{\pi \phi \mu_i c_{ti} (t_{DA})}_{match}}$$

$$r_{wa} = \frac{r_e}{\left(\frac{r_e}{r_{wa}} \right)_{match}}$$

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

$$G = \frac{(0.00633)(1.417 * 10^6) S_g p_i T_{sc}}{\mu_i c_{ti} Z_i p_{sc}} \left(\frac{t_{ca}}{t_{DA}} \right)_{match} \left(\frac{p_D}{\frac{\Delta p_p}{q}} \right)_{match} * 10^9 \text{ (Bscf)}$$

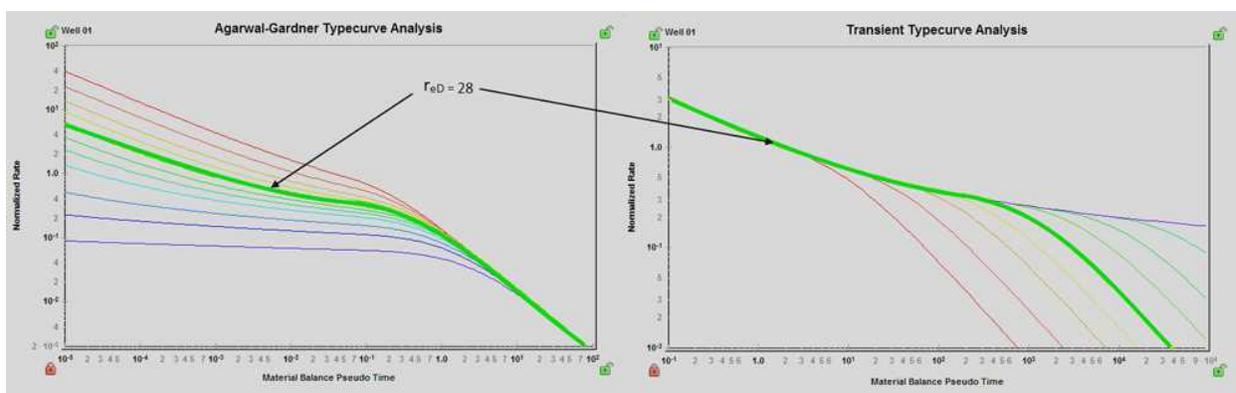
Fracture typecurves

The NPI fracture typecurves are the inverse of the Agarwal-Gardner rate-time fracture typecurves.

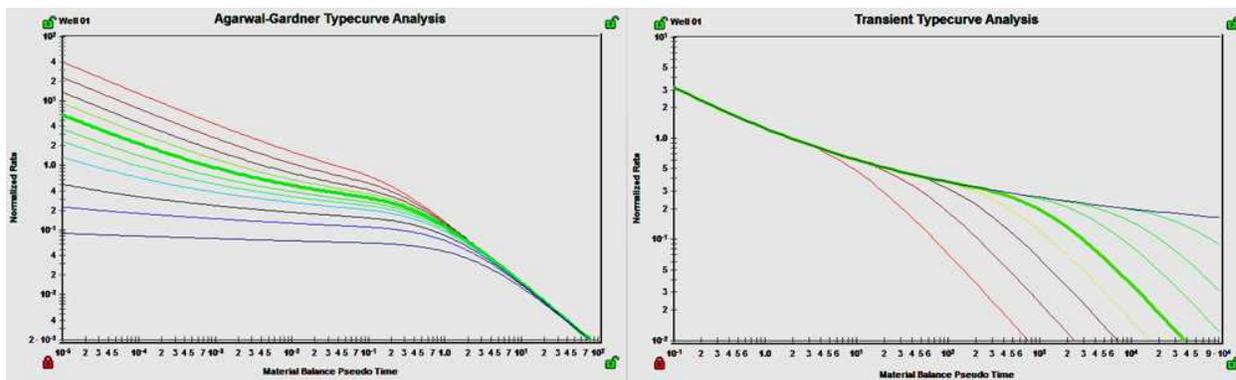
Transient typecurve theory

The transient typecurve analysis method provides an alternative perspective that is ideal for analysis of very short (early) production periods, and/or analysis of very low permeability reservoirs.

In the Blasingame, Agarwal-Gardner and Normalized Pressure Integral methods, the typecurves are scaled such that there is convergence onto a single boundary-dominated stem (unit slope). This is achieved through the use of a dimensionless time that is based on area (t_{DA} or t_{DD}). One consequence of this type of scaling is that there are numerous transient stems. If a dimensionless time based on well radius (t_D) is chosen instead, there will be a single transient stem with a series of boundary-dominated curves. When viewing a single typecurve (e.g., $r_{eD} = 28$) there is no difference between these two scaling formats (see figure below). However, when viewing all the typecurves together, the transient presentation provides a more convenient base for analysis of transient data. This follows from the fact that selection of an appropriate transient stem is not required.



Consider a transient production data set (either very low permeability, or limited production life). A comparison of the typecurve match using Agarwal-Gardner Rate-Time analysis with that of the Transient format is shown below.



It is clear from this example that the transient presentation of the typecurves provides a more unique typecurve match. For the same reason that transient data works better with the transient format (q_D vs. t_D), it should be noted that boundary-dominated flow analysis is not advised using this method.

The accepted time-superposition function for Rate Transient Analysis is material balance time. Since material balance time is rigorous for boundary-dominated flow, it is a natural standard for evaluating variable rate production data. However, when dealing with transient data, it is clearly not the best option. The standard time-superposition for transient flow (pressure transient analysis) is radial-superposition time. When using the transient typecurves in RTA, both the radial and linear superposition time options are available.

Inverse pressure integral derivative

This derivative can make typecurve matching easier by exaggerating features in the data. In most cases, the inverse pressure derivative was found to be too sensitive to be useful. The inverse pressure integral derivative is less sensitive and so can be interpreted more handily, while still providing detail about the character of the data.

We start with dimensionless pressure:

$$q_D = \frac{1}{p_D}$$

Next we define the dimensionless pressure integral:

$$p_{Di} = \frac{1}{t_D} \int p_D dt_D$$

This is used to define the inverse pressure integral derivative:

$$\frac{1}{p_{Di d}} = \frac{1}{\left(\frac{dp_{Di}}{d \ln(t_D)} \right)}$$

This can also be written as:

$$\frac{1}{p_{Di d}} = \frac{1}{\left(t_{DA} \frac{dp_{DI}}{dt_D}\right)}$$

Data preparation

The horizontal axis is material balance time (pseudo-time for gas).

On the vertical axis, two variables are plotted:

- Normalized Rate vs. Material Balance Time
- Inverse of Semi-log Derivative vs. Material Balance Time

Normalized rate

Oil wells

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

$$\frac{1}{DER} = \left[\frac{\partial \frac{\Delta p}{q}}{\partial \ln(t_c)} \right]$$

Gas Wells

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

$$\frac{1}{DER} = \frac{1}{\left[\begin{array}{c} \frac{\partial \Delta p_p}{q} \\ \frac{\partial \ln(t_{ca})}{\partial \ln(t_{ca})} \end{array} \right]}$$

Note: In the modified (RTA) plot, the 1 / DER_i (inverse pressure integral derivative) is also included.

Analysis

The normalized rate and inverse semi-log derivative data are plotted against material balance time on a log-log scale of the same size as the typecurves. This plot is called the "data plot". Any convenient units can be used for normalized rate or time because a change in units simply causes a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates; especially when transient data are analyzed.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel, until a good match is obtained. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and its "r_e / r_{wa}" (r_e / x_f for fractured case) value is noted.

Typecurve analysis is done by selecting a match point, and reading its coordinates off the data plot (q / Δp and t_c)_{match}, and off the typecurve plot (q_D and t_D)_{match}. At the same time the stem value "r_e / r_{wa}" (r_e / x_f for fracture typecurves) of the matching curve is noted.

To create a forecast, the selected typecurve is traced on to the data plot, and extrapolated. The future rate is read from the data plot, off the traced typecurve.

Calculation of parameters: radial typecurves

Oil wells

Permeability is obtained by rearranging the definition of dimensionless rate:

$$q_D = \frac{141.2 q B \mu}{k h (p_i - p_{wf})}$$

$$k = \frac{141.2 B \mu \left(\frac{q/\Delta p}{q_D} \right)_{match}}{h}$$

$$t_D = \frac{0.00633 k t_c}{\phi \mu c_t r_{wa}^2}$$

Solve for apparent wellbore radius from the definitions of dimensionless time and permeability:

$$r_{wa} = \sqrt{\frac{0.00633 \left(\frac{141.2 B}{h} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_D} \right)_{match}}{\phi c_t}}$$

Skin factor is calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

Volume and area parameters are calculated as follows:

$$N = \pi \frac{S_o}{c_t} \left(\frac{0.00633 * 141.2 B}{h} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_D} \right)_{match} \left(\frac{(r_{eD})^2}{5.615 * 10^3} \right) \text{ (Mbbbls)}$$

$$A = \frac{5.615 * 10^3 N B_o}{\phi S_o h} \frac{1}{43560} \text{ (Acres)}$$

Gas wells

Permeability is obtained by rearranging the definition of dimensionless rate:

$$q_D = \frac{1.417 * 10^6 T_R}{k h} \frac{q}{\Delta p_p}$$

$$k = \frac{1.417 * 10^6 T_R}{h} \left(\frac{q/\Delta p_p}{q_D} \right)_{match}$$

$$t_D = \frac{0.00633 k t_{ca}}{\phi \mu_i c_{ti} r_{wa}^2}$$

Solve for apparent wellbore radius from the definitions of dimensionless time and permeability:

$$r_{wa} = \sqrt{\frac{0.00633}{\phi \mu_i c_{ti}} \left(\frac{1.417 * 10^6 T_R}{h} \right) \left(\frac{t_{ca}}{t_D} \right)_{match} \left(\frac{q/\Delta p_p}{q_D} \right)_{match}}$$

Skin factor is calculated as follows:

$$s = \ln \left(\frac{r_w}{r_{wa}} \right)$$

Volume and area parameters are calculated as follows:

$$G = \frac{\pi (0.00633)(1.417 * 10^6) S_g p_i T_{sc}}{\mu_i c_{ti} Z_i p_{sc}} \left(\frac{t_{ca}}{t_D} \right)_{match} \left(\frac{q/\Delta p_p}{q_D} \right)_{match} (r_{eD})_{match}^2 * 10^{-9} \text{ (Bcf)}$$

$$A = \frac{G Z_i T p_{sc}}{\phi h S_g p_i T_{sc}} \frac{1}{43560} \text{ (Acres)}$$

Calculation of parameters: finite conductivity fracture typecurves

The finite conductivity fracture typecurves are based on a square-shaped reservoir with a hydraulic fracture in the center. They are plotted using dimensionless time format, and are therefore categorized as transient format curves. The transient stems represent three different dimensionless fracture conductivity (FCD) values (0.5, 5, and 500). The boundary dominated stems diverge at each of four (1, 2, 5, 25) dimensionless reservoir length (x_{eD}) values.



Definitions

Dimensionless fracture conductivity:

$$F_{CD} = \frac{k_f w}{k x_f}$$

Dimensionless reservoir length / width:

$$X_{eD} = \frac{X_e}{x_f}$$

Where $2X_e$ = primary reservoir dimension

Oil wells

Permeability is obtained by rearranging the definition of dimensionless rate:

$$q_D = \frac{141.2 q B \mu}{k h (p_i - p_{wf})}$$

$$k = \frac{141.2 B \mu \left(\frac{q/\Delta p}{q_D} \right)_{match}}{h}$$

$$t_D = \frac{0.00633 k t_c}{\phi \mu c_t x_f^2}$$

Solve for fracture half-length from the definitions of dimensionless time and permeability:

$$x_f = \sqrt{\frac{0.00633 \left(\frac{141.2 B}{h} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_D} \right)_{match}}{\phi c_t}}$$

Volume and area parameters are calculated as follows:

$$N = \frac{S_o}{c_t} \left(\frac{0.00633 * 141.2 B}{h} \right) \left(\frac{q/\Delta p}{q_D} \right)_{match} \left(\frac{t_c}{t_D} \right)_{match} \left(\frac{(2 X_{eD})^2}{5.615 * 10^3} \right) \text{ (Mbbls)}$$

$$A = \frac{5.615 * 10^3 N B_o}{\phi S_o h} \frac{1}{43560} \text{ (Acres)}$$

Gas wells

Permeability is obtained by rearranging the definition of dimensionless rate:

$$q_D = \frac{1.417 * 10^6 T_R}{k h} \frac{q}{\Delta p_p}$$

$$k = \frac{1.417 * 10^6 T_R}{h} \left(\frac{q / \Delta p_p}{q_D} \right)_{match}$$

$$t_D = \frac{0.00633 k t_{ca}}{\phi \mu_i c_{ti} x_f^2}$$

Solve for fracture half-length from the definitions of dimensionless time and permeability:

$$x_f = \sqrt{\frac{0.00633 \left(\frac{1.417 * 10^6 T_R}{h} \right) \left(\frac{t_{ca}}{t_D} \right)_{match} \left(\frac{q / \Delta p_p}{q_D} \right)_{match}}$$

Volume and area parameters are calculated as follows:

$$G = \frac{(0.00633)(1.417 * 10^6) S_g p_i T_{sc}}{\mu_i c_{ti} Z_i p_{sc}} \left(\frac{t_{ca}}{t_D} \right)_{match} \left(\frac{q / \Delta p_p}{q_D} \right)_{match} (2 X_{eD})_{match}^2 * 10^{-9} \text{ (Bcf)}$$

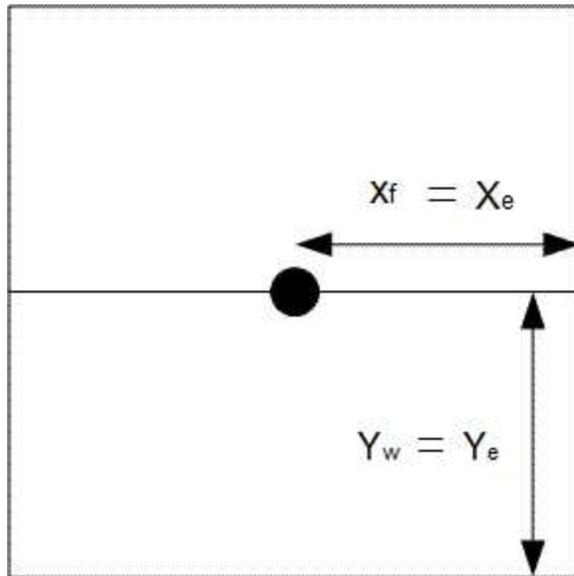
$$A = \frac{G Z_i T p_{sc}}{\phi h S_g p_i T_{sc}} \frac{1}{43560} \text{ (Acres)}$$

Wattenbarger typecurve theory

Extended periods of linear flow have been observed in many gas wells. These wells are usually in very tight gas reservoirs with hydraulic fractures designed to extend to the drainage boundary of

the well. Wattenbarger et al. (1998) presented new typecurves to analyze the production data of these gas wells.

They assumed a hydraulically fractured well in the center of a rectangular reservoir. The fracture is assumed to be extended to the boundaries of the reservoir.



They showed that the solution in case of constant rate production and closed reservoir is:

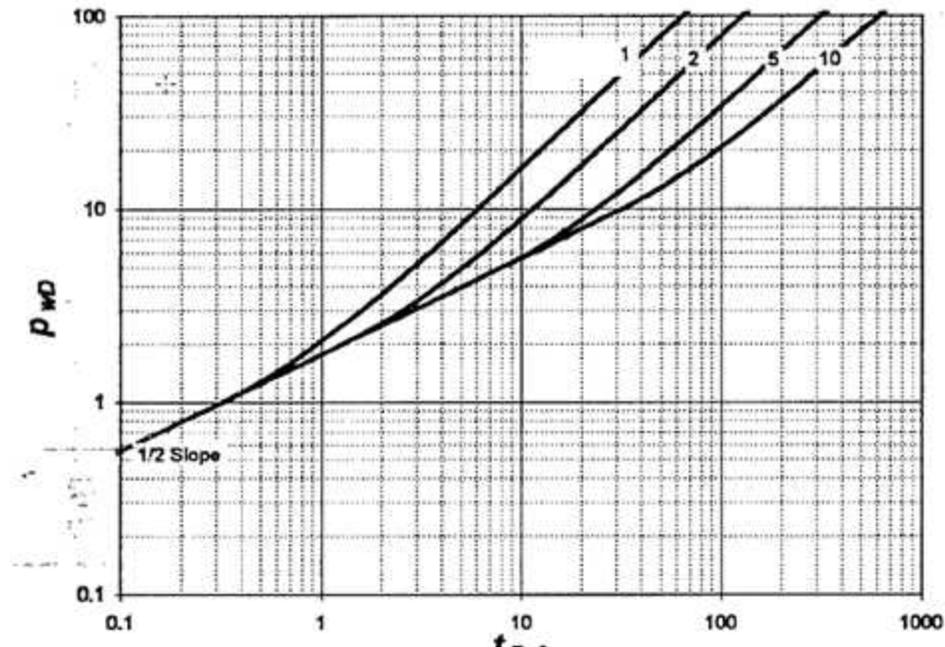
$$p_D = \frac{\pi}{2} \left(\frac{Y_e}{x_f} \right) \left[\frac{1}{3} + \left(\frac{x_f}{Y_e} \right)^2 t_{Dxf} \right] - \frac{2}{\pi^2} \left(\frac{Y_e}{x_f} \right) \sum_{n=1}^{\infty} \frac{1}{n^2} e \left[-n^2 \pi^2 \left(\frac{x_f}{Y_e} \right)^2 t_{Dxf} \right]$$

Where dimensionless variables are defined as:

$$p_D = \frac{k h (p_i - p_{wf})}{141.2 q B \mu}$$

$$t_{Dxf} = \frac{0.00633 k t}{\phi \mu c_t x_f^2}$$

The typecurves based on this equation are shown below. Wattenbarger et al. (1998) showed that there are different typecurves for different values of x_f / Y_e .



The solution for linear flow can be rewritten as:

$$\left(\frac{x_f}{Y_e}\right) p_D = \frac{\pi}{2} \left[\frac{1}{3} + t_{Dye} \right] - \frac{2}{\pi^2} \sum_{n=1}^{\infty} \frac{1}{n^2} e^{-n^2 \pi^2 t_{Dye}}$$

where:

$$t_{Dye} = \frac{0.00633 k t}{\phi \mu c_t Y_e^2} = \left(\frac{x_f}{Y_e}\right)^2 t_{Dxf}$$

This equation shows that plotting $[(x_f / Y_e) * p_D]$ against t_{Dye} gives only one curve for any rectangular geometry, rather than families of typecurves with different values of x_f / Y_e .

In RTA, this analysis has been modified as follows:

- $[(Y_e / x'_e) * q_D]$ is plotted against t_{Dye} instead of $[(x_f / Y_e) * p_D]$.
- The typecurves are generated for cases where the well is not in the center of the reservoir (different values for Y_e / Y_w).
- In addition to dimensionless rate, the inverse of semi-log pressure derivative curve is included.

Methodology

Data preparation

The horizontal axis is material balance time (pseudo-time for gas).

On the vertical axis, two variables are plotted:

- Normalized rate
- Inverse of semi-log pressure derivative

Normalized rate

Oil wells

$$\frac{q}{\Delta p} = \frac{q}{p_i - p_{wf}}$$

Gas wells

$$\frac{q}{\Delta p_p} = \frac{q}{p_{pi} - p_{pwf}}$$

Inverse of semi-log pressure derivative

Oil wells

$$\frac{1}{DER} = \left[\frac{1}{\frac{\partial \frac{\Delta p}{q}}{\partial \ln(t_c)}} \right]$$

Gas wells

$$\frac{1}{DER} = \left[\frac{1}{\frac{\partial \frac{\Delta p_p}{q}}{\partial \ln(t_{ca})}} \right]$$

Analysis

The normalized rate and inverse semi-log pressure derivative are plotted against the material balance time on a log-log scale of the same size as the typecurves. This plot is called the “data plot”. Any convenient units can be used for normalized rate or time because a change in units simply caused a uniform shift of the raw data on a logarithmic scale. It is recommended that daily operated-rates be plotted, and not the monthly rates; especially when transient data are analyzed.

The data plot is moved over the typecurve plot, while the axes of the two plots are kept parallel until a good match is obtained. Several different typecurves should be tried to obtain the best fit of all the data. The typecurve that best fits the data is selected and Y_e / Y_w value is noted.

Calculation of parameters

Oil wells

Using the definition of $[q_D (Y_e / X_e)]$:

$$q_D \frac{Y_e}{X_e} = \frac{141.2 B \mu}{k h} \frac{q}{\Delta p} \frac{Y_e}{X_e}$$

$k X_e / Y_e$ is calculated as follows:

$$\frac{k X_e}{Y_e} = \frac{141.2 B \mu}{h} \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match}$$

where $(q / \Delta p)$ and $[q_D (Y_e / X_e)]$, are read off from each of the raw data and typecurve graphs at a selected match point.

From the definition of dimensionless time based on reservoir width (t_{Dye}):

$$t_{Dye} = \frac{0.00633 k t_c}{\phi \mu c_t Y_e^2}$$

(Y_e / \sqrt{k}) is calculated as follows:

$$\frac{Y_e}{\sqrt{k}} = \sqrt{\frac{0.00633}{\phi \mu c_t} \left(\frac{t_c}{t_{Dye}} \right)_{match}}$$

Substituting the equation for [($k X_e / Y_e$)] into the above, we get:

$$\sqrt{k} X_e = \sqrt{\frac{0.00633}{\phi \mu c_t} * \frac{141.2 B \mu}{h} * \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match}} * \sqrt{\left(\frac{t_c}{t_{Dye}} \right)_{match}}$$

Additional reservoir parameters are now calculated:

$$\begin{aligned} A &= 4 X_e Y_e = 4 * (\sqrt{k} X_e) \frac{Y_e}{\sqrt{k}} \frac{1}{43560} \\ &= \frac{4 * 0.00633}{\phi c_t} * \frac{141.2 B}{h} * \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match} * \left(\frac{t_c}{t_{Dye}} \right)_{match} * \frac{1}{43560} \end{aligned}$$

(Acres)

$$\begin{aligned} N &= \frac{4 X_e Y_e h \phi S_{oi}}{B} * \frac{1}{5.615 * 10^3} \\ &= \frac{4 * 0.00633 * 141.2}{c_t} * \left[\frac{\left(\frac{q}{\Delta p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match} * \left(\frac{t_c}{t_{Dye}} \right)_{match} * \frac{S_{oi}}{5.615 * 10^3} \end{aligned}$$

(Mbbl)

Gas wells

Using the definition of [$q_D(Y_e / X_e)$]:

$$q_D \frac{Y_e}{X_e} = \frac{1.417 * 10^6 T}{k h} \frac{q}{\Delta p_p} \frac{Y_e}{X_e}$$

(k X_e / Y_e) is calculated as follows:

$$\frac{k X_e}{Y_e} = \frac{1.417 * 10^6 T}{h} \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match}$$

where (q / Δp_p) and [q_D (Y_e / X_e)] are read off from each of the raw data and typecurve graphs at a selected match point.

From the definition of t_{Dye},

$$t_{Dye} = \frac{0.00633 k t_{ca}}{\phi \mu c_t Y_e^2}$$

(Y_e / √k) is calculated as follows:

$$\frac{Y_e}{\sqrt{k}} = \sqrt{\frac{0.00633}{\phi \mu c_t} \left(\frac{t_{ca}}{t_{Dye}} \right)_{match}}$$

Substituting the equation for (k X_e / Y_e) into the above, we get:

$$\sqrt{k} X_e = \sqrt{\frac{0.00633}{\phi \mu c_t} * \frac{1.417 * 10^6 T}{h} * \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match}} * \sqrt{\left(\frac{t_{ca}}{t_{Dye}} \right)_{match}}$$

Additional reservoir parameters are now calculated:

$$A = 4 X_e Y_e = 4 * (\sqrt{k} X_e) * \frac{Y_e}{\sqrt{k}} * \frac{1}{43560}$$

$$= \frac{4 * 0.00633}{\phi \mu c_t} * \frac{1.417 * 10^6 T}{h} * \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match} * \left(\frac{t_{ca}}{t_{Dye}} \right)_{match} * \frac{1}{43560}$$

(Acres)

$$G = \frac{4 X_e Y_e h \phi S_{gi}}{B_{gi}} * 10^{-9}$$

$$= \frac{4 * 0.00633 * 1.417 * 10^6 T}{\mu c_t} \left[\frac{\left(\frac{q}{\Delta p_p} \right)}{q_D \frac{Y_e}{X_e}} \right]_{match} * \left(\frac{t_{ca}}{t_{Dye}} \right)_{match} * \frac{S_{gi}}{B_{gi}} * 10^{-9}$$

(Bscf)

Typewell theory

The distribution of rates is used to generate the range of production history lines corresponding with P90, P50, P10 cases. (For example, for each period, the P90 point is determined as the value for which 90% of the data points are higher—or for the more common description, the value for which 10% of the values are smaller.) The data points in this case are the rates for each well at a specific period. If a group of groups is selected, the aggregate rates for each group are used.

To determine this value, all data points for a period must be sorted in ascending order. N is the number of data points in the period. P is the percentile. (In the P90 example P is 10.) The position of the percentile value is n.

$$n = \frac{P}{100} (N - 1) + 1$$

The value of n is split into its integer (k) and decimal (d) components such that $n = k + d$

The percentile value (v_p) is calculated by:

$$v_p = v_k + d(v_{k+1} - v_k)$$

The production volume for each period is calculated in the same way as the rate.

The cumulative production track is calculated by summing the calculated volumes for each period.

For example:

We have the following dataset:

1.18	1.28	0.95	2.49	1.35	1.82	1.46	3.96	1.33	1.40
3.72	3.11	2.32	2.20	1.75	4.57	2.22	4.12	2.79	3.95

The values are set to ascending order:

0.95	1.18	1.28	1.33	1.35	1.40	1.46	1.75	1.82	2.20
2.22	2.32	2.49	2.79	3.11	3.72	3.95	3.96	4.12	4.57

The percentile to be found is 10 (P90). N=20.

Next, n is determined:

$$n = \frac{10}{100} (20 - 1) + 1 = 2.9$$

From n = 2.9, k = 2 and d = 0.9.

Then we find v_2 is 1.18 and v_3 is 1.28.

Finally $v_k + d(v_{k+1} - v_k) = 1.18 + 0.9(1.28 - 1.18) = 1.27$.

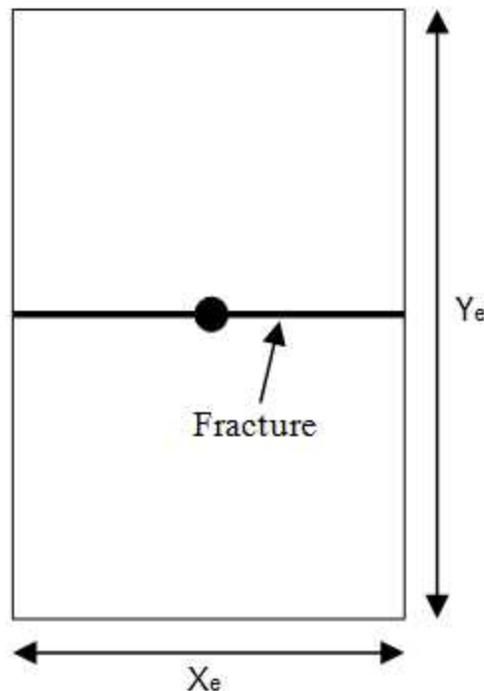
The P90 rate for this period is 1.27.

Unconventional reservoir theory

Production behavior of unconventional reservoirs

The term "unconventional" refers to production from very low-permeability formations. This often includes shale and very tight sands. When the permeability of a formation is very low, an enormous amount of surface area is required between the well completion and the reservoir to be able to produce at economic rates. This required area is achieved through multiple stages of massive fracture stimulations. The flow regime most often observed in these wells is linear flow. Linear flow may last several years and is often the only flow regime observed in the analysis. In addition to fractures created in the reservoir, linear flow can be caused by natural fracturing or enhancements to the natural fractures. For more information see [fracture properties](#).

The effective drainage boundaries for these wells often coincide with the fracture length. In other words, drainage beyond the stimulated region is not significant and in the analysis method presented, this contribution is neglected. The base reservoir geometry used to develop this method is that of a single fracture centered in a rectangular reservoir, where the fracture width extends to the reservoir boundary. In this geometry, linear flow is observed until the reservoir width (Y_e) boundary is reached, and the well enters boundary-dominated flow. The reservoir geometry is shown below:



Constant flowing pressure

Current analysis techniques in the industry use material balance time. Since material balance time is actually boundary-dominated flow superposition time, these analyses may appear to show boundary-dominated flow even when the reservoir is still exhibiting transient flow. In the method presented, no superposition functions are used, which avoids a bias towards any flow regimes. The production data is analyzed using a plot of reciprocal rate versus square-root time. In this plot, linear flow appears as a straight-line trend. The basic assumption is of infinite conductivity in the fracture; finite conductivity manifests itself as a positive intercept on the plot. The equations presented are based on the assumption of a constant flowing pressure at the well. This is a reasonable simplification for tight gas and shale production, where wells are typically produced under high drawdown.

Based on the straight-line behavior of the square root time plot, the simplest form of the linear flow equation is:

Equation 1

$$\frac{1}{q} = m\sqrt{t} + b'$$

In this equation, the intercept captures a number of near well effects, such as skin and finite fracture conductivity, and the slope is given by:

For oil:

Equation 2a

$$m = \frac{31.3 B}{h x_f \sqrt{k}} \sqrt{\frac{\mu}{\varphi c_t}} \times \frac{1}{p_i - p_{wf}}$$

For gas:

Equation 2b

$$m = \frac{315.4 T}{h \sqrt{(\varphi \mu_g c_t)_i}} \times \frac{1}{p_i - p_{wf}} \times \frac{1}{x_f \sqrt{k}}$$

From the slope of the equation, fracture half-length and permeability are determined as a single product. To determine either explicitly, the other parameter must be known.

To determine the skin effect, the intercept of the line is used with the following:

For oil:

Equation 2c

$$s' = \frac{b' (p_i - p_{wf}) k (2 x_f)}{141.2 B \mu}$$

Equation 2d

$$F'_{CD} = \frac{141.2 B \mu}{b' (p_i - p_{wf}) k h n_f} \times \left(1 + \frac{h}{x_f} \left(\ln \left(\frac{h}{2 r_w} \right) - \frac{\pi}{2} \right) \right)$$

For gas:

Equation 2e

$$s' = \frac{b' (p_{pi} - p_{pwf}) k (2 x_f)}{1.417 \times 10^6 T}$$

Equation 2f

$$F'_{CD} = \frac{1.417 \times 10^6 T}{b' (p_{pi} - p_{pwf}) k h n_f} \times \left(1 + \frac{h}{x_f} \left(\ln \left(\frac{h}{2 r_w} \right) - \frac{\pi}{2} \right) \right)$$

Duration of linear flow

When a well is producing under constant flowing pressure, the distance of investigation can be obtained from the following equation during the linear flow period:

Equation 3

$$Y = 0.159 \sqrt{\frac{k t}{(\varphi \mu c_t)_i}}$$

Combining this equation with the reservoir geometry detailed in the diagram presented previously, the end of linear flow is given by the following:

Equation 4

$$\frac{Y_e}{2} = 0.159 \sqrt{\frac{k t_{elf}}{(\varphi \mu c_t)_i}}$$

Equation 4 can be rearranged as follows:

Equation 5

$$t_{elf} = \left(\frac{Y_e \sqrt{(\varphi \mu c_t)_i}}{2 \times 0.159 \sqrt{k}} \right)^2$$

This is not a practical form of the equation, since permeability (k) and reservoir width (Y_e) are usually not explicitly known. The permeability is tied into the $(x_f\sqrt{k})$ term and reservoir width is related to the drainage area (A); however, both of these are related to fracture half-length (x_f). Using the definition of drainage area ($A = 2 * x_f * Y_e$), equation 5 becomes:

Equation 6a

$$t_{elf} = \left(\frac{A \sqrt{(\varphi \mu c_t)_i}}{4 \times 0.159} \times \frac{1}{x_f \sqrt{k}} \right)^2$$

The $(x_f\sqrt{k})$ term is determined from the slope of the square-root time plot using a rearranged form of [equation 2](#). For unconventional gas reservoirs, $x_f\sqrt{k}$ departs from its analytical value as the pressure drawdown, D_D , becomes higher. To correct for this drawdown effect, a correction factor, f_{cp} , is implemented in the gas constant pressure module, which allows for a more accurate determination of $x_f\sqrt{k}$.

D_D and f_{cp} are defined as follows:

Equation 6b

$$D_D = \frac{[p_{pi} - p_{pwf}]}{p_{pi}}$$

Equation 6c

$$f_{CP} = 1 - 0.0852 D_D - 0.0857 D_D^2$$

$x_f\sqrt{k}$ can be determined by using following equations:

For oil:

Equation 7a

$$x_f = \sqrt{k} = \frac{31.3 B}{m h} \times \frac{1}{p_i - p_{wf}} \times \sqrt{\frac{\mu}{\varphi c_t}}$$

For gas:

Equation 7b

$$x_f \sqrt{k} = f_{cp} \frac{315.4 T}{m h (p_{pi} - p_{pwf})} \sqrt{\frac{1}{(\varphi \mu c_t)_i}}$$

Substituting equation 7 into equation 6a, the duration of linear flow (and hence the beginning of boundary-dominated flow) is determined using the following equation:

For oil:

Equation 8a

$$t_{elf} = \left[\frac{A h (\varphi c_t) m (p_i - p_{wf})}{19.9 B} \right]^2$$

For gas:

Equation 8b

$$t_{elf} = \left[\frac{A h (\varphi \mu_g c_t) m (p_{pi} - p_{pwf})}{200.6 T} \right]^2$$

An approximation of the gas equation can be obtained by replacing pseudo-pressure terms with:

Equation 8c

$$\frac{p_i^2 - p_{wf}^2}{(\mu_g Z)_i}$$

and c_{ti} by the inverse of p_i

The major unknown in determining the end of linear flow is the effective drainage area. Analog wells can be used to determine an appropriate range of drainage areas for the subject well. Well spacing can provide an upper bound on drainage area in high-density developments. Interpretation of flowing material balance can be used to determine a minimum area based on the current production data.

Boundary-dominated flow

Given the geometry of the reservoir considered, linear flow is followed directly by boundary-dominated flow. There are two ways to represent this flow regime for purposes of forecasting: (a) pseudo-steady state equations, material balance time, and pseudo-time; (b) traditional (Arps) hyperbolic decline. In the interest of keeping the method simple and practical, the hyperbolic decline method is used. Hyperbolic decline is defined in the following equation:

Equation 9

$$q = \frac{q_i}{[1 + b a_i t]^{\frac{1}{b}}}$$

In this equation, q_i and a_i are flow rate and decline rate (respectively) at the start of the forecast period; and t is the time that has elapsed since the start of the forecast. Since the hyperbolic decline forecast starts at the end of linear flow, the flow rate, decline rate, and time will be with respect to time at the end of linear flow (t_{elf}). The decline exponent (b) is selected to be between 0 and 0.5, which are typical values for boundary-dominated flow in gas. Equation 9 is then rewritten to represent this:

Equation 10

$$q = \frac{q_{elf}}{[1 + b a_{elf} (t - t_{elf})]^{\frac{1}{b}}}$$

Equation 10 is rewritten to show how rate at the end of linear flow (q_{elf}) is determined based on the interpretation of the square-root time plot:

Equation 11

$$q_{elf} = \frac{1}{m \sqrt{t_{elf}} + b'}$$

Decline rate from the hyperbolic decline equation is defined as:

Equation 12

$$a = - \frac{1}{q} \frac{dq}{dt}$$

In order to determine decline rate at the end of linear flow (a_{elf}), an expression is needed for decline rate during linear flow. This is obtained by combining Equation 1 and Equation 12:

Equation 13

$$a = \frac{1}{m\sqrt{t} + b'} \frac{m}{2\sqrt{t}}$$

This equation is now written to reflect the decline rate at the end of linear flow:

Equation 14

$$a_{elf} = \frac{1}{m\sqrt{t_{elf}} + b'} \frac{m}{2\sqrt{t_{elf}}}$$

From Equation 14, it is also apparent that if b is negligible, the equation reduces to:

Equation 15

$$a = \frac{1}{2t}$$

Once a decline exponent (b) is selected, [Equation 10](#) can be used for any duration of forecast, and even to determine the production forecast based on an abandonment rate.

Variable flowing pressure

In the initial development of this interpretation technique, constant flowing pressure has been assumed. An additional case for variable flowing pressure may also be considered when interpreting the square-root time plot. The standard y-axis of reciprocal rate is simply replaced with normalized pressure to account for changes in flowing pressure during the linear flow portion of the data. Transient linear flow appears to be a straight line in the normalized pressure versus square-root of time plot. The slope of the straight line, m , is used to calculate $x_f\sqrt{k}$ with the following:

For oil:

Equation 16a

$$x_f \sqrt{k} = \frac{19.927 B}{m h} \sqrt{\frac{\mu}{\varphi c_t}}$$

For gas:

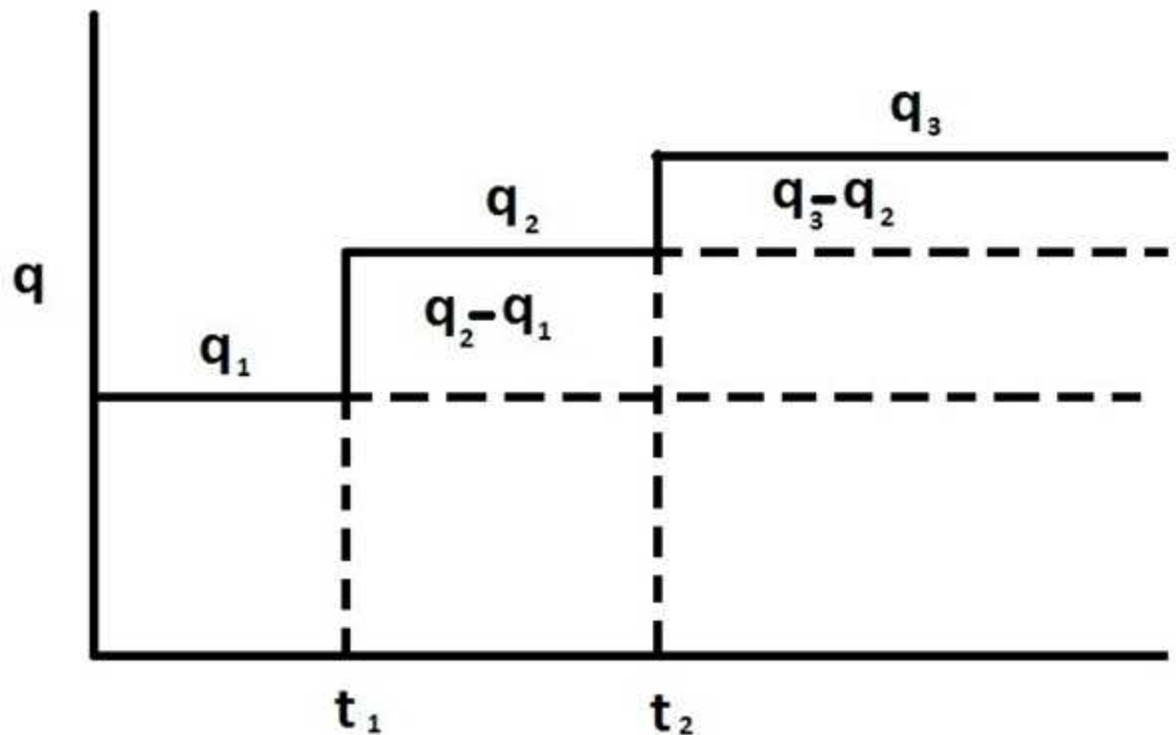
Equation 16b

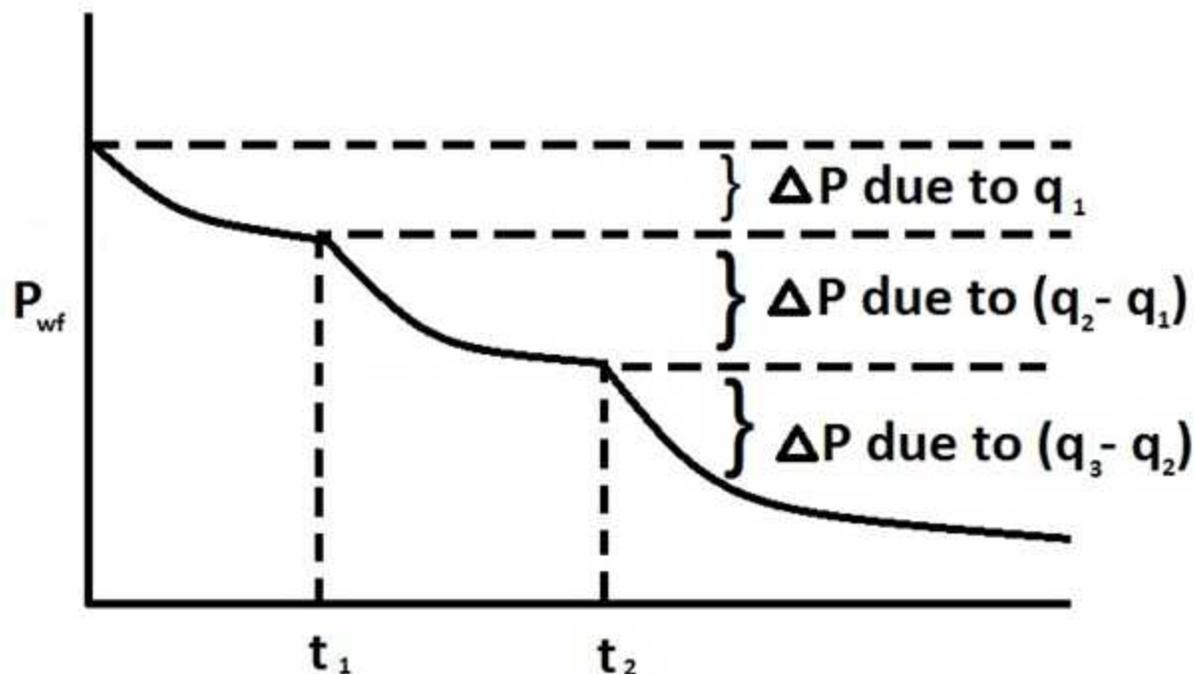
$$x_f \sqrt{k} = f_{cp} \frac{200.8 T}{m h} \sqrt{\frac{1}{(\varphi \mu c_t)_i}}$$

As stated earlier, the observation has been that most unconventional wells are produced at very high drawdown rates to maximize recovery. Because of this common practice, the forecasting approach in the variable pressure module uses hyperbolic decline with the assumption of constant pressure for the duration of the forecast.

Superposition time

Superposition is a mathematical tool. You can use simple solutions (such as constant rates) to produce complex ones (such as variable rates). Superposition uses the theory that a rate that changes from q_1 at time t to a new rate q_2 is equivalent to q_1 continuing forever, superposed, or added on ($q_2 - q_1$) starting at time t and continuing forever.





For unconventional reservoirs, two superposition time functions are commonly used in production analysis: linear superposition time and material balance time.

Linear superposition time is given by:

Equation 17a

$$t_n = \sum_{j=1}^n \frac{q_j - q_{j-1}}{q_n} \sqrt{t - t_{j-1}}$$

Material balance time is given by:

Equation 17b

$$t_c = \frac{Q_n}{q_n}$$

Both two superposition time functions can effectively convert variable rates to their equivalent constant rates solutions. Therefore, the plot of $\frac{p_i - p_{wf}}{q}$ versus linear superposition time (or square root of material balance time) on a Cartesian graph results in a straight line. The slope of this line (m') can be used to calculate $x_f \sqrt{k}$:

For oil:

Equation 17c

$$x_f \sqrt{k} = \frac{19.927 B}{m' h} \sqrt{\frac{\mu}{\varphi c_t}}$$

For gas:

Equation 17d

$$x_f \sqrt{k} = \frac{200.8 T}{m' h} \sqrt{\frac{1}{(\varphi \mu c_t)_i}}$$

Using pseudo-time

The above derivations used for the unconventional reservoir module (URM) analysis do not account for variation in total compressibility. It is possible to account for variation in total compressibility and fluid viscosity by using pseudo-time.

Pseudo-time is defined as follows:

For oil:

$$t_a(t) = \frac{\mu_o(p_i) c_t(p_i)}{k(p_i)} \int_0^t \frac{k(\bar{p}_{inv})}{\mu_o(\bar{p}_{inv}) c_t(\bar{p}_{inv})} dt$$

For gas:

$$t_a(t) = \frac{\mu_g(p_i) c_t(p_i)}{k(p_i)} \int_0^t \frac{k(\bar{p}_{inv})}{\mu_g(\bar{p}_{inv}) c_t(\bar{p}_{inv})} dt$$

In these equations, \bar{p}_{inv} , is average pressure over the volume investigated at a given time t .

Note: The correction factor, f_{CP} , (defined in Equation 6c) is another way to account for variation in gas compressibility. Therefore, when pseudo-time is used, there is no need to use the correction factor, f_{CP} , in calculations.

Accounting for variation in rock and fluid properties in the oil URM

In the descriptions above, URM analysis for gas is done in terms of pseudo-pressure, and URM analysis for oil is done in terms of pressure. This is done because for the oil case, a variation of oil properties (such as viscosity, compressibility, and the formation volume factor) is considered to be negligible, and formation compressibility and permeability are assumed to be constant (no geo-mechanical effects).

However in some cases, it is important to account for a variation in oil and formation properties. This can be done similarly to how it is done for gas cases, by introducing oil pseudo-pressure:

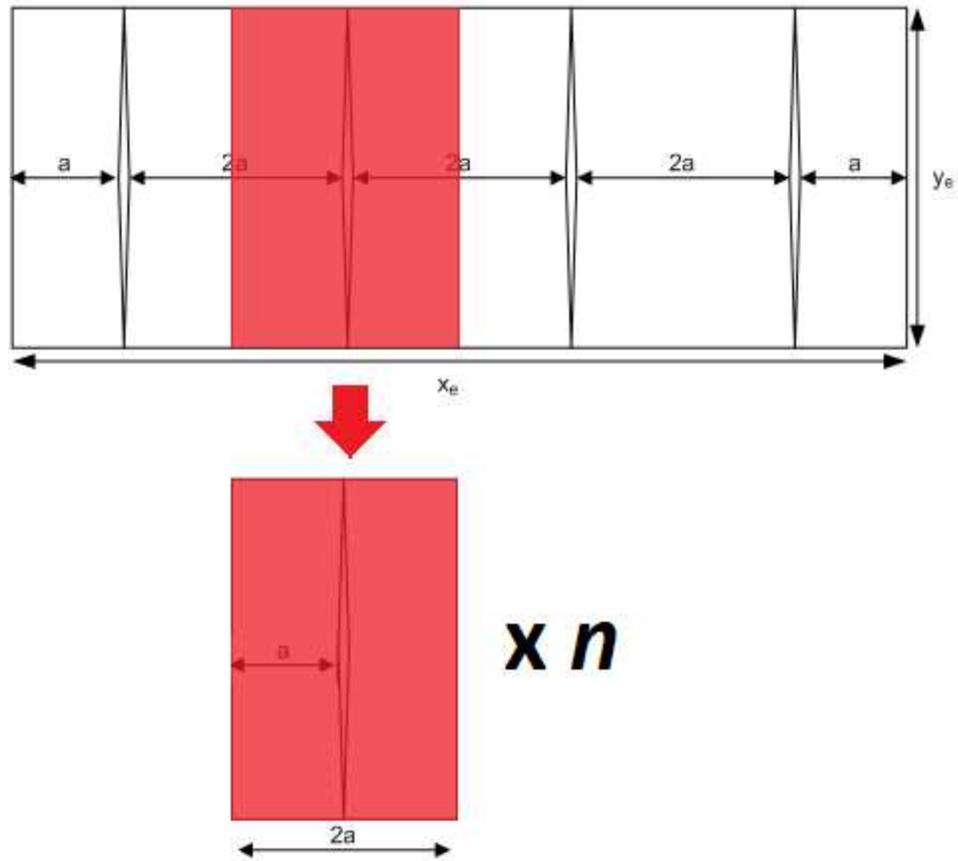
$$p_{po}(p) = \frac{B_o(p_i) \mu_o(p_i)}{k(p_i)} \int_0^p \frac{k(p)}{B_o(p) \mu_o(p)} dp$$

When the oil URM calculation is modified to use pseudo-pressure, the FMB plot within the URM dashboard is also modified. For information on modifications for the oil FMB plot, see [accounting for variation in oil properties \(FMB\)](#).

Note: This approach is used and described in literature, including [Behmanesh et al. \(2015\)](#), [Stalgorova and Mattar \(2016\)](#).

Application to horizontal wells

The majority of wells in unconventional gas production are horizontal wells with multiple stage fracturing. The approach first considered with the development of this method is to treat the horizontal wellbore as a fracture, and incorporate fracture stimulation in this well as part of the effective permeability interpreted on the square-root time plot. An additional method has been incorporated using the same process as that developed for a single fracture. If the horizontal well is cased, or contributes very little production compared to the fractures, the well can be treated as a series of fractures in the reservoir. In a well with n equally spaced and identically sized fractures, the single fracture model can be multiplied by n fractures to represent the whole well. The linear flow into the fractures is followed by boundary-dominated flow when no-flow boundaries are formed between adjacent fractures. This layout is displayed below with its relationship to the single-fracture model.



Applying this theory to Harmony Reservoir™

This theory applies to using production data to identify the linear flow parameter and interpret the linear flow parameter for different completion types.

Using production data to identify the linear flow parameter

Equations 16a and 16b can be rewritten as:

For oil:

Equation 18a

$$4hx_f \sqrt{k} = 4 \cdot \frac{19.927 B}{m} \sqrt{\frac{\mu}{\phi c_t}}$$

For gas:

Equation 18b

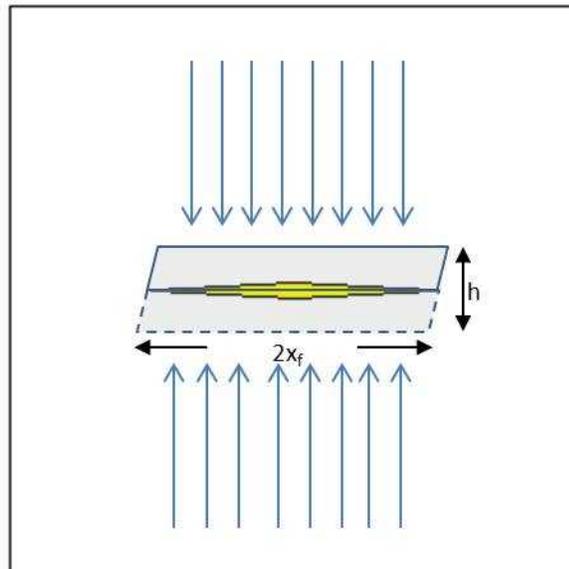
$$4hx_f\sqrt{k} = 4 \cdot \frac{200.8T}{m} \sqrt{\frac{1}{(\varphi\mu c_t)_i}}$$

Note: Equations 17c and 17d can be rewritten in a similar way.

These equations are derived for the case where the well is being produced through a single fracture. For this case, the total area to flow (A_c) can be calculated as:

Equation 19

$$A_c = 4h x_f$$



Therefore, equations 20a and 20b can be rewritten in a general form:

For oil:

Equation 20a

$$A_c \sqrt{k} = 4 \cdot \frac{19.927 B}{m} \sqrt{\frac{\mu}{\varphi c_t}}$$

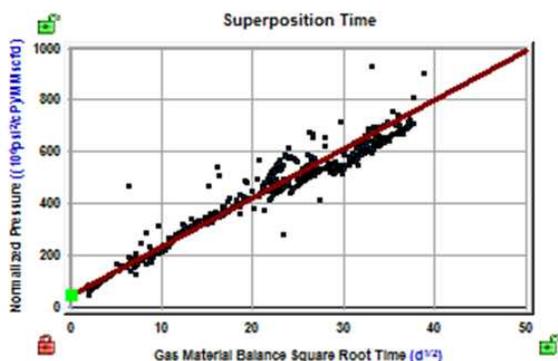
For gas:

Equation 20b

$$A_c \sqrt{k} = 4 \cdot \frac{200.8T}{m} \sqrt{\frac{1}{(\varphi\mu c_t)_i}}$$

Where A_c is total area to flow.

In equations 20a and 20b, the right-side of the equation is known: m , and is defined by production data (the slope of the line for normalized pressure plotted against a \sqrt{t} function), and the remaining parameters are known for reservoir and fluid properties. Therefore, we can calculate the linear flow parameter $A_c \sqrt{k}$ using the top-left plot on the URM dashboard.



→ slope of the line → $A_c \sqrt{k}$

Note: A_c represents the total area to flow, without any assumptions whether the well is producing through a single fracture, through multiple fractures, or through a non-fractured horizontal wellbore.

Interpreting the linear flow parameter for different completion types

Once the value for the linear flow parameter $A_c \sqrt{k}$ is calculated, it can be interpreted differently depending on the type of completion. With the URM analysis, three types of completion are selectable from the Model Type drop-down list.

The following sections describe how the linear flow parameter is interpreted for each model type.

Vertical – single frac model type

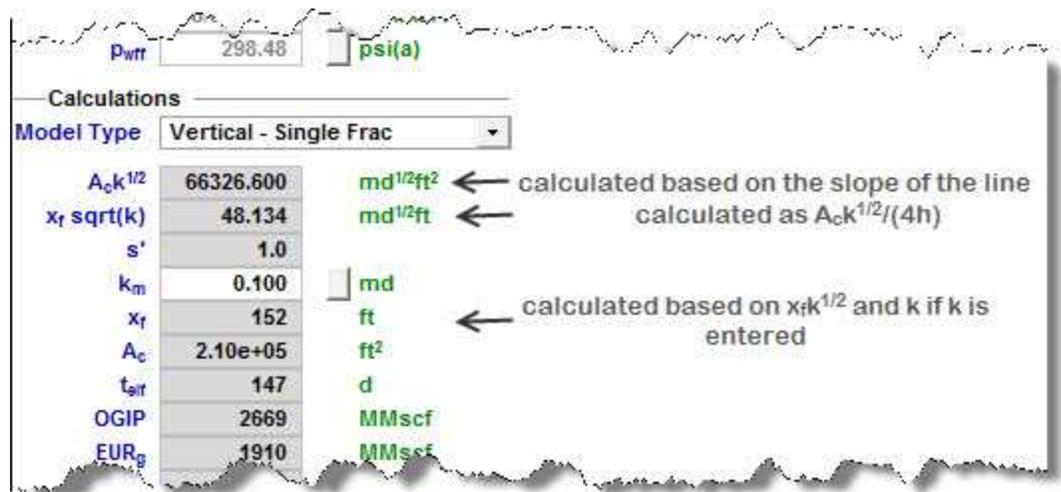
In this case, it is assumed that the well is being produced through a single fracture. We can observe linear flow towards the fracture from both sides. The total area to flow (A_c) can be calculated as:

Equation 21

$$A_c = 4 h x_f$$

Where h is the known net pay. Once $A_c \sqrt{k}$ is calculated, $x_f \sqrt{k}$ is also calculated and reported.

If you enter the value for permeability, x_f will be calculated based on the known value of permeability, and the previously calculated $x_f \sqrt{k}$.



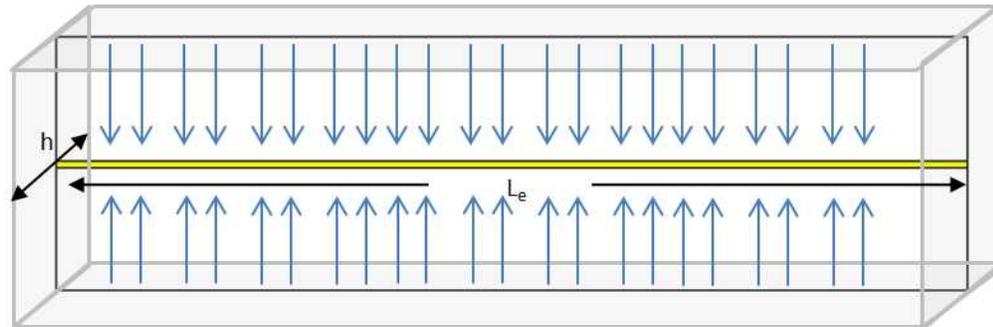
Horizontal Multifrac – effective k model type

In this case, it is assumed that the well is being produced through a horizontal wellbore without fractures. This model can also be used when the well is fractured, but we do not model each individual fracture; instead we account for all the fractures by using higher effective permeability. Then, we can observe linear flow towards the wellbore.

Total area to flow (A_c) can be calculated as:

Equation 22

$$A_c = 2 h L_e$$



Where h is the known net pay. Once $A_c\sqrt{k}$ is calculated, $L_e\sqrt{k}$ can also be calculated.

Note: As there is no x_f in this model type, the parameter $x_f\sqrt{k}$ should be interpreted as $(L_e/2)\sqrt{k}$.

If you enter the value for effective horizontal wellbore length, L_e , effective permeability k_e will be calculated based on the known L_e and the previously calculated $L_e\sqrt{k}$.

Calculations		
Model Type	Hz - Multi Frac - Effective k	
$A_c k^{1/2}$	62787.709	md ^{1/2} ft ² ← calculated based on the slope of the line
$x_f \sqrt{k}$	45.566	md ^{1/2} ft ← should be interpreted as $(L_e/2)k^{1/2}$
s^*	0.1	
L_e	2000.0	ft ← calculated based on $L_e k^{1/2}$ and L_e if L_e is entered
k_e	2.076e-03	md
A_c		ft ²
t_{air}	240	d
OGIP	2669	MMscf
EUR _g	2217	MMscf
G	41	MMscf

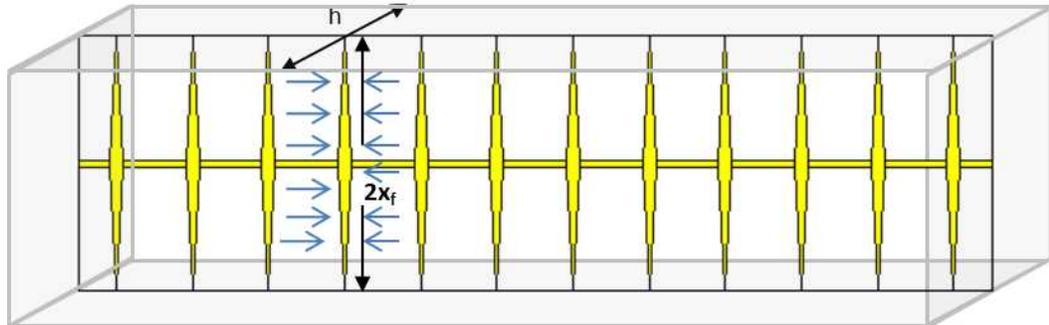
Horizontal Multifrac – SRV model type

In this case, it is assumed that the well is being produced through multiple fractures (n_f = number of fractures). Then, we can observe linear flow towards each fracture.

The total area to flow (A_c) can be calculated as:

Equation 23

$$A_c = 4 n_f x_f h$$



Where h is the known net pay. Once $A_c \sqrt{k}$ is calculated, $n_f x_f \sqrt{k}$ can also be calculated.

For this completion type, there is another relationship between model parameters:

Equation 24

$$OFIP = 2 x_f \cdot L_e \cdot h \cdot \varphi \cdot S_{fi} / B_{fi}$$

Where:

$OFIP$: original fluid in place – this value can be obtained from the Flowing Material Balance plot

h : net pay; known reservoir property

φ : porosity; known reservoir property

S_{fi} : initial saturation of the modeled fluid (oil or gas); known reservoir property

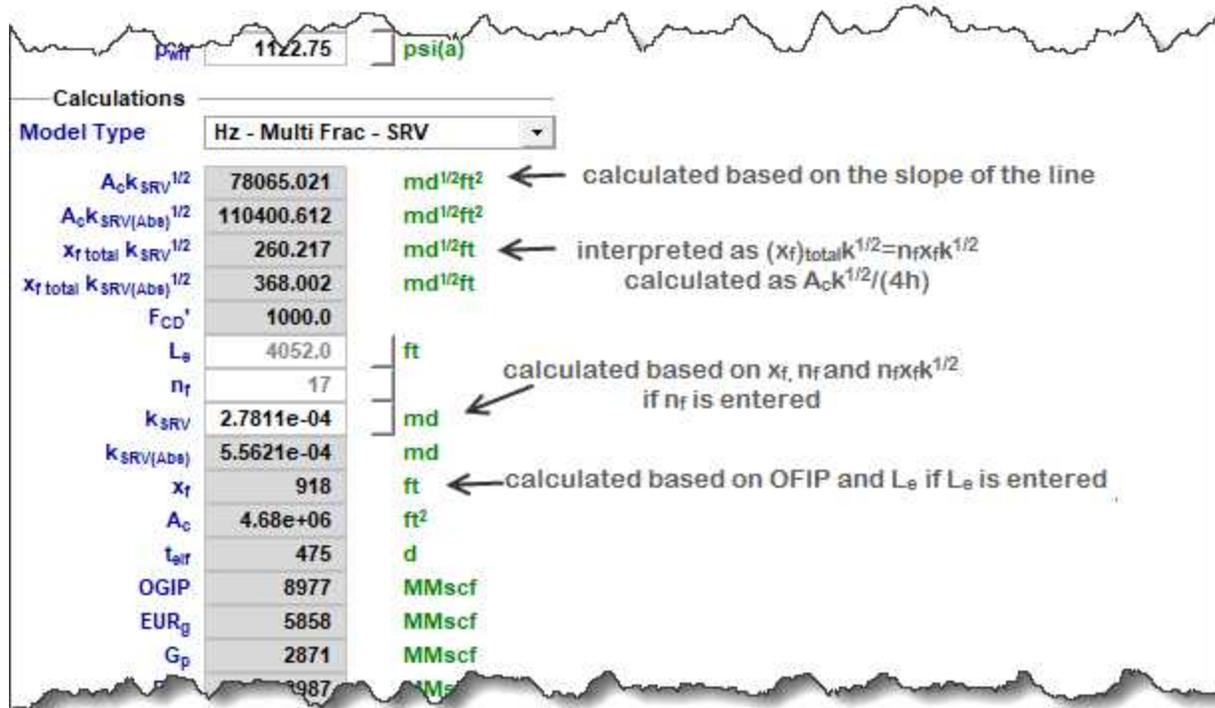
B_{fi} : initial formation volume factor of the modeled fluid (oil or gas); known fluid property

L_e : effective horizontal well length

x_f : fracture half-length

In Equation 24, all parameters except for L_e and x_f are known. Therefore, if you enter the value for L_e , x_f can be calculated.

If you enter the value for n_f , permeability can be calculated based on the previously calculated $n_f x_f \sqrt{k}$, x_f , and the given n_f .

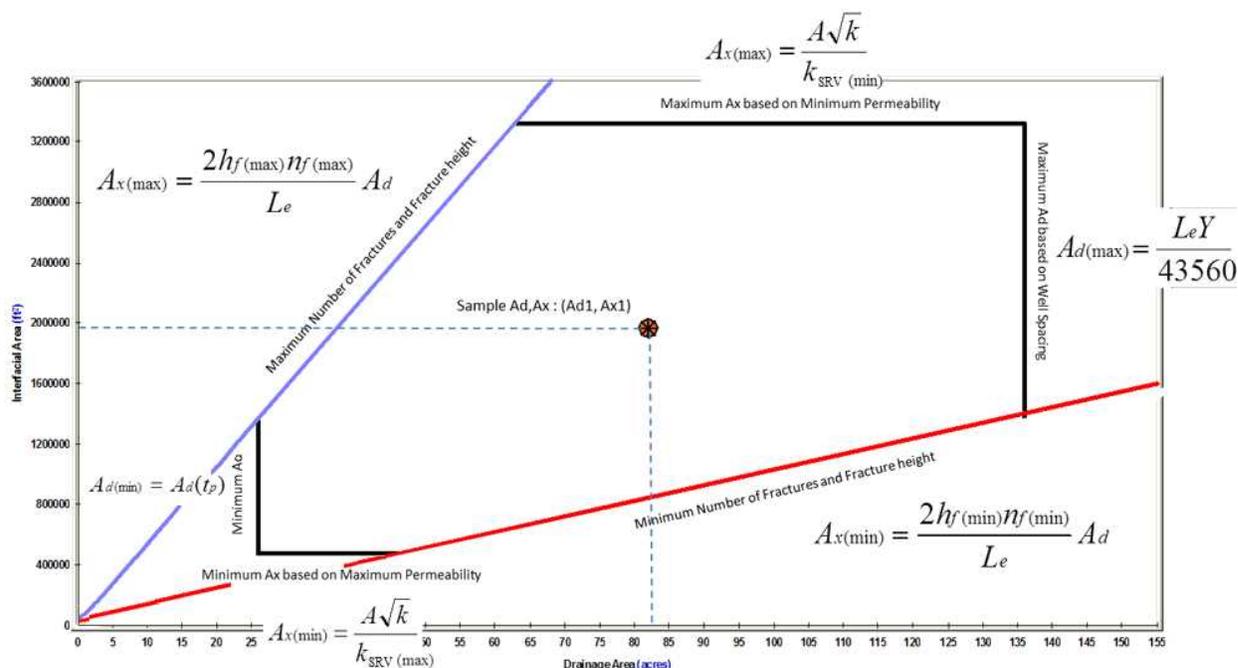


Most likely model

This model is a new methodology for identifying the possible range of stimulated reservoir volume (SRV) configurations based on specified well performance data, assumed system geometry, and known external system constraints.

The method is based on providing single values for known completion and petrophysical properties, and lower / upper limits for unknown parameters. The method is suitable for early well performance data, where transient linear flow is dominant.

The method is graphics-based with a plot of the exposed area of the fractures (A_x) versus drainage area of the reservoir (A_d). Based on user-defined constraints and limits, this plot defines a region that contains the full set of possible SRV configurations.



The definition of the allowable range of A_x versus A_d is identified in two parts.

Part 1: identify the region that defines minimum & maximum values for A_x and A_d

Limiting values for A_x are determined as follows:

Important: All of the equations below are referenced *earlier* in this topic.

Equation 18a

$$A_{x(\min)} = \frac{A \sqrt{k}}{\sqrt{k_{SRV(\max)}}}$$

Equation 18b

$$A_{x(\max)} = \frac{A \sqrt{k}}{\sqrt{k_{SRV(\min)}}}$$

Where $A\sqrt{k}$ is extracted from the slope of the square root straight line on the specialized plot, and $k_{SRV(\min)}$ and $k_{SRV(\max)}$ define the acceptable range of the unknown parameter, Stimulated Region Permeability.

The parameter k_{SRV} is considered to be an effective permeability, inclusive of any natural or induced fractures that have been activated (or are naturally active) and are connected to the primary hydraulic fracture network, but it does not include the primary fracture permeability. In other words, it is the permeability that acts directly on the primary hydraulic fracture system. A_x is defined as the total area exposed to fractures. For a fracture of half-length (x_f), A_x is defined as:

Equation 18c

$$A_c = 4hx_f$$

Limiting values for A_d are determined as follows:

Equation 18d

$$A_{d(\min)} = A_d(t_p)$$

Equation 18e

$$A_{d(\max)} = L_e Y \text{ or } A_{d(\max)} = \frac{L_e Y}{43560} \text{ if } A_d \text{ is in acres}$$

Where:

$A_d(t_p)$ equals the currently contacted drainage area, which is determined from a combined analysis of the square root straight line and the flowing material balance (Anderson et al. 2010).

Y equals the projected average distance between adjacent laterals once the field has been fully developed.

Based on the above, a box-shaped region can be defined on a plot of A_x versus A_d .

Part 2: identify the functional relationship between A_x and A_d

Assuming parallel transverse fractures (slab model) of uniform distribution and length, A_d is a linear function of A_x as follows:

Equation 19a

$$A_x = \frac{2 h_f n_f}{L_e} A_d$$

If the fracture network is assumed to be 2-dimensional (matchstick geometry), the coefficient in the above equation becomes 4. If the fracture network is assumed to be 3-dimensional (sugar cube geometry), the coefficient becomes 6.

Since h_f and n_f are unknowns, we can define the minimum and maximum functional relationship between A_x and A_d , assuming that we can provide allowable ranges for h_f and n_f .

Equation 19b

$$A_{x(\min)} = \frac{2 h_{f(\min)} n_{f(\min)}}{L_e} A_d$$

Equation 19c

$$A_{x(\max)} = \frac{2 h_{f(\max)} n_{f(\max)}}{L_e} A_d$$

The above equations plot as straight lines through the origin on the A_x versus A_d plot. The intersection of the previously defined rectangular region with these straight lines yields a region that contains all the possible A_d and A_x combinations.

Formulae for calculating reservoir / completion properties, given a sample configuration (A_{d1} , A_{x1}) from the A_x - A_d region, are shown as follows:

Equation 19d

$$x_f(A_{d1} A_{x1}) = \frac{A_{d1}}{2 L_e}$$

Equation 19e

$$k_{SRV}(A_{d1} A_{x1}) = \left(\frac{A \sqrt{k}}{A_{x1}} \right)^2$$

Equation 19f

$$h_f n_f(A_{d1} A_{x1}) = \frac{A_{x1} L_e}{2 A_{d1}}$$

Equation 19g

$$FCD'_{(A_{d1}A_{x1})} = \frac{1.417 E6 T}{b' k h_f n_f} \left(1 + \frac{h_f}{x_f} \left(\ln \left(\frac{h_f}{2 r_w} \right) - \frac{\pi}{2} \right) \right)$$

The mass center of the Allowable A_x versus A_d region is used to calculate the "most likely" values.

Volumetrics theory

Volumetric analysis is a technique that uses geological observations and information to estimate original fluids-in-place. It is often referred to as a "static method" as it primarily sources its data from core samples, wireline logs, and geological maps. Volumetric calculations are typically used prior to production to estimate reserves, and after considerable production to determine the efficiency of recovery, the areal extent of the reservoir, and as a basis for advanced studies, such as reservoir simulations.

Volume Parameter Equations and Equalities	
Rock Volume	$V_R = A \times h$
Pore Volume	$V_P = V_R \times \phi = A \times h \times \phi$
Hydrocarbon Pore Volume	$V_{HCP} = V_P \times (S_{HC}) = A \times h \times \phi \times (S_{HC})$ Where S_{HC} = the hydrocarbon saturation of interest (either S_o or S_g)

A comprehensive geologic study of the prospect is necessary to increase the confidence and reliability of determined reservoir properties, such as volume, porosity, and fluid saturations. In calculating the volume of the reservoir, accurate determinations of the areal extent and thickness must be made with respect to the geological structure and depositional environment. The use of isopach maps in combination with planimetry is a commonly used method in the determination of reservoir volume. Conclusions drawn concerning lithofacies and depositional settings are used to provide an assessment of porosity, while wireline log and core data provide the analyst with measurements of fluid saturations.

Oil reservoir calculations

Original Oil-in-Place (OOIP) Calculations		
Field Units [stb]	$OOIP = 7758 \times \frac{V_{HCP}}{B_{oi}}$ <p>Or, in expanded form:</p> $OOIP = 7758 \times A \times h \times \phi \times (S_{oi}) \times \frac{1}{B_{oi}}$	Where: A = acres h = feet ϕ = fraction S _{oi} = fraction B _{oi} = bbl/stb
Metric Units [m ³]	$OOIP = \frac{V_{HCP}}{B_{oi}}$ <p>Or, in expanded form:</p> $OOIP = A \times h \times \phi \times (S_{oi}) \times \frac{1}{B_{oi}}$	Where: A = square meters h = meters ϕ = fraction S _{oi} = fraction B _{oi} = m ³ /m ³

Gas reservoir calculations

Historically, in a gas reservoir, only *free* gas-in-place was considered. Because of this, only one name was required: OGIP. However, with the increasing use of adsorbed gas reservoirs in the industry, Fekete / IHS has adopted the name “OGIP_F” to define the gas-in-place for a free-gas reservoir. Likewise, the name “OGIP_A” is used to define the gas-in-place in a reservoir. The name OGIP has been retained to describe the total original gas-in-place.

Free gas equations

Original Free Gas-in-Place (OGIP _F) Calculations		
Field Units [scf]	$OGIP_F = 43560 \times \frac{V_{HCP}}{B_{gi}}$ <p>Or, in expanded form:</p> $OGIP_F = 43560 \times A \times h \times \phi \times (S_{gi}) \times \frac{1}{B_{gi}}$	Where: A = acres h = feet ϕ = fraction

Original Free Gas-in-Place (OGIP _F) Calculations		
		<p>S_{gi} = fraction</p> <p>B_{gi} = ft³/scf</p>
<p>Metric Units</p> <p>[m³]</p>	<p>$OGIP_F = \frac{V_{HCP}}{B_{gi}}$</p> <p>Or, in expanded form:</p> <p>$OGIP_F = A \times h \times \phi \times (S_{gi}) \times \frac{1}{B_{gi}}$</p>	<p>Where:</p> <p>A = square meters</p> <p>h = meters</p> <p>φ = fraction</p> <p>S_{gi} = fraction</p> <p>B_{gi} = m³/m³</p>

Adsorbed gas equations – shale reservoirs

Shale gas reservoirs usually contain much more adsorbed gas than free gas. Therefore, OGIP calculations for shale reservoirs should also account for adsorption. For shale reservoirs, total gas in place is calculated as:

$$OGIP = OGIP_F + OGIP_A$$

The following equations are used to calculate the original adsorbed gas-in-place (OGIP_A).

Original Adsorbed Gas-in-Place (OGIP _A) Calculations		
<p>Field Units</p> <p>[scf]</p>	<p>$OGIP_A = 43560 \times A \times h \times \rho_b \times \frac{V_{L\\$} \times p}{p_{L\\$} + p}$</p>	<p>Where:</p> <p>A = acres</p> <p>h = feet</p> <p>ρ_b = ton/ft³</p> <p>p = psi(a)</p> <p>V_{L\$} = scf/ton</p>

Original Adsorbed Gas-in-Place (OGIP _A) Calculations		
		p _L = psi(a)
Metric Units [m ³]	$OGIP_A = A \times h \times \rho_b \times \frac{V_{L\à} \times p}{p_{L\à} + p}$	Where: A = square meters h = meters $\rho_b = \text{g/cm}^3$ p = kPa(a) $V_{L\à} = \text{cm}^3/\text{g}$ p _L = kPa(a)

Adsorption saturation option

Adsorbed gas may occupy a portion of the measured porosity. To account for this, you can use the Adsorption Saturation option. If this option is selected, the calculation for OGIP_A remains unchanged, but the calculation for OGIP_F uses a decreased value for gas saturation. For information on the calculation for this adjusted S_g, see the [shale adsorption correction](#).

For adsorption theory, see [shale properties](#).

Calculations for liquid-rich gas reservoirs

With liquid-rich gas, it is important to calculate the original dry gas-in-place (OGIP_d), as well as the original condensate-in-place (OCIP).

Original dry gas in-place comes from free gas and dissolved gas:

$$OGIP_d = OGIP_{dF} + OGIP_S$$

Original condensate in-place comes from free condensate and vaporized condensate:

$$OCIP = OCIP_F + OCIP_V$$

The following equations are used to calculate OGIP_{dF}, OGIP_S, OCIP_F, and OCIP_V:

Calculations for Liquid-Rich Gas		
Field Units [scf, stb]	$OGIP_{dF} = 43560 \times A \times h \times \emptyset \times S_{gi} \times \frac{1}{B_{gdi}}$ $OCIP_F = 7758 \times A \times h \times \emptyset \times S_{ci} \times \frac{1}{B_{ci}}$	Where: A = acres h = feet

Calculations for Liquid-Rich Gas		
	$OGIP_S = OCIP_F \times R_{si}$ $OCIP_V = OGIP_{dF} \times R_{vi}$	ϕ = fraction S_{gi}, S_{ci} = fraction B_{gi} = ft ³ /scf B_{ci} = bbl/stb R_{si} = stb/scf R_{vi} = scf/stb
Metric Units [m ³ , m ³]	$OGIP_{dF} = A \times h \times \phi \times S_{gi} \times \frac{1}{B_{gdi}}$ $OCIP_F = A \times h \times \phi \times S_{ci} \times \frac{1}{B_{ci}}$ $OGIP_S = OCIP_F \times R_{si}$ $OCIP_V = OGIP_{dF} \times R_{vi}$	Where: A = square meters h = meters ϕ = fraction S_{gi}, S_{ci} = fraction B_{gi} = m ³ /m ³ B_{ci} = m ³ /m ³ R_{si} = m ³ /m ³ R_{vi} = m ³ /m ³

Note that the formation volume factor used to calculate the original dry gas-in-place is B_{dgi} — the formation volume factor for *dry* gas. It is different from B_{gi} — the formation volume factor for *recombined* gas displayed in the Properties editor. The dry gas formation volume factor (B_{dgi}) is defined as the ratio of the gas phase volume at reservoir conditions (V_g) to the equivalent volume of its gas component at standard conditions. The formation volume factor for recombined gas is the value obtained using given gas correlations based on the recombined gas gravity. For more information, see [recombination](#).

WOR forecasting theory

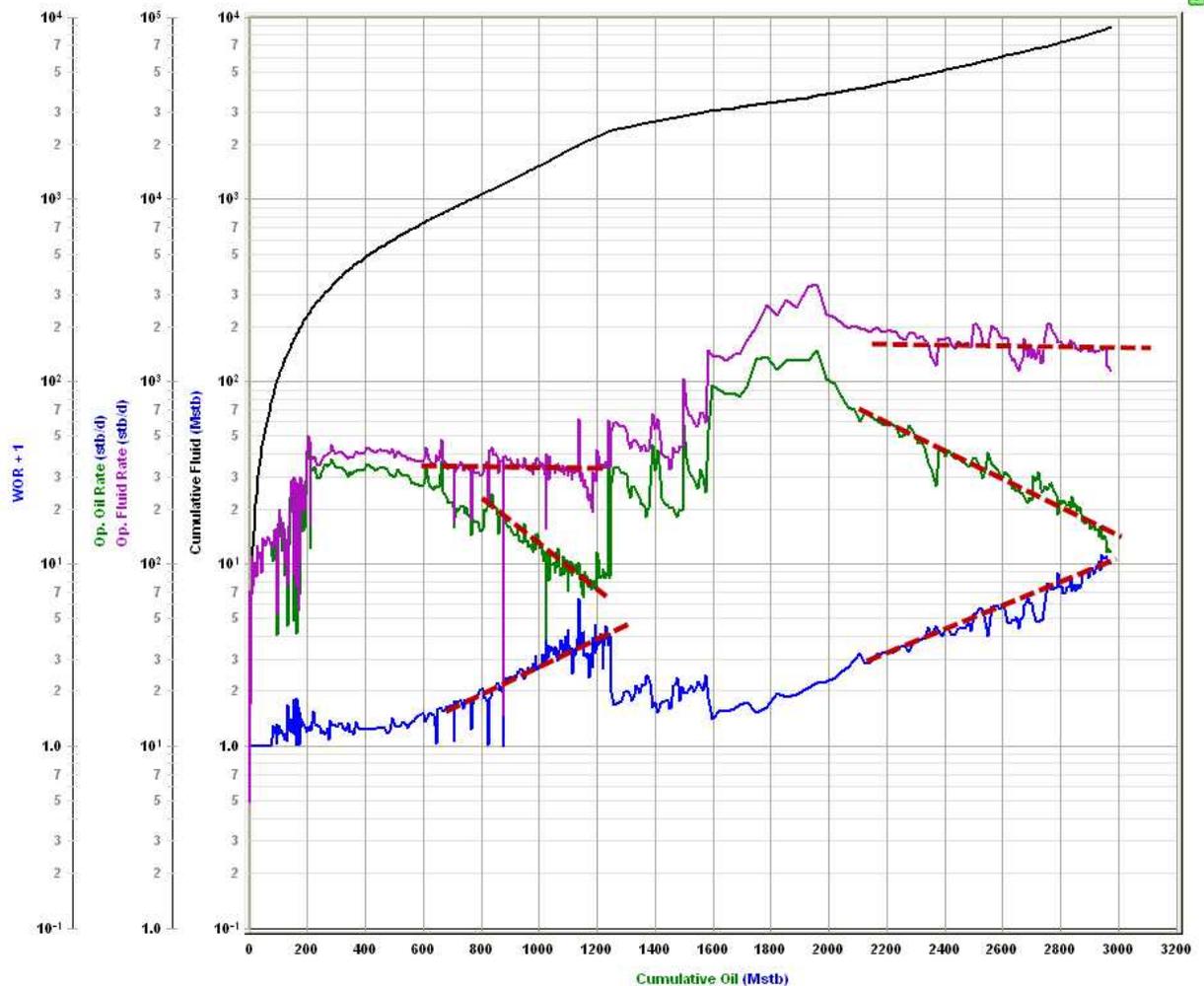
Water-oil ratio (WOR) forecasting is a method of trending future water production for the purpose of forecasting oil production and determining expected ultimate recoverable s (EUR). Water-oil ratio forecasting is an empirical analysis method; there is no formal model or equations. Plots of both water-oil ratio and water-oil ratio +1 are used in forecasting, and the plots are typically semi-log with cumulative oil production as the x-axis. Water-oil ratio, water-oil ratio +1, and water cut are defined below:

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

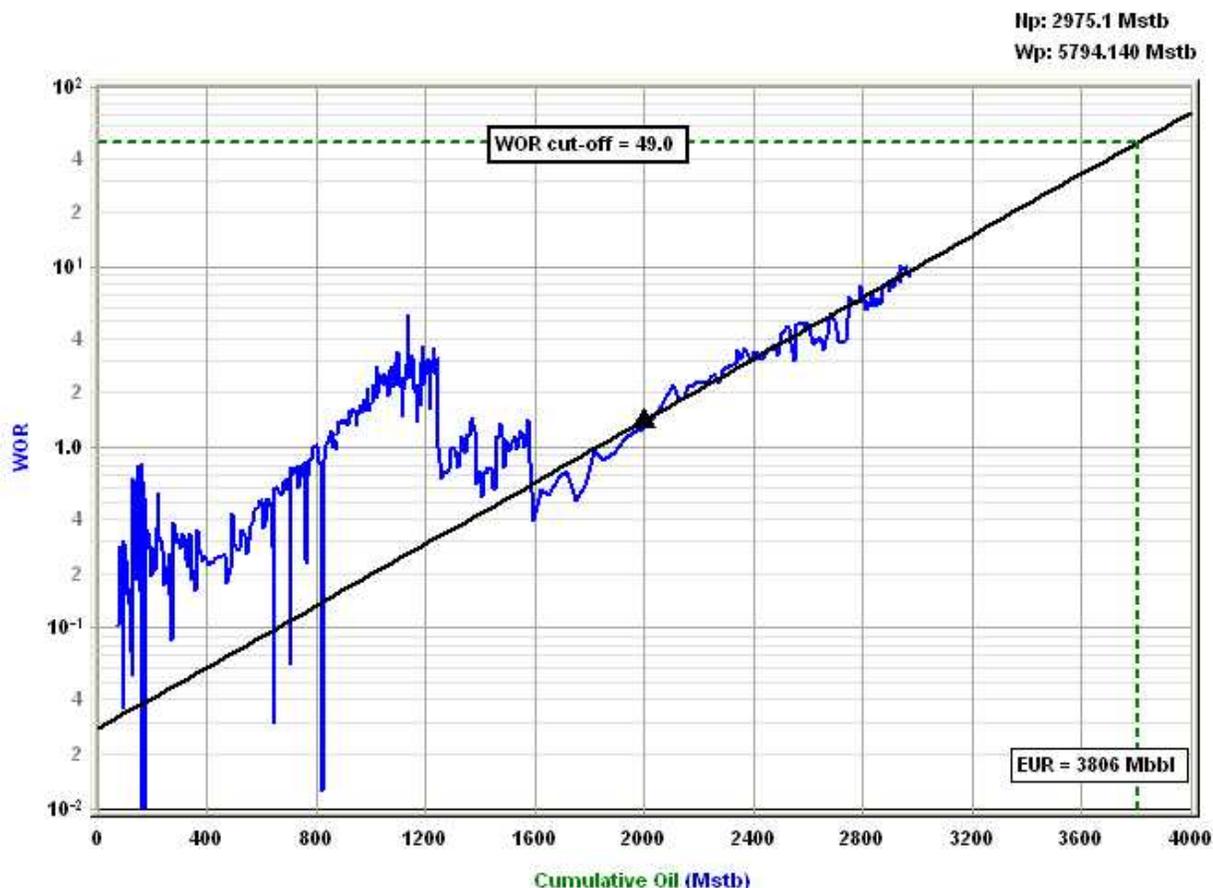
$$WOR + 1 = \frac{q_w + q_o}{q_o}$$

$$Water\ cut = \frac{WOR}{WOR + 1}$$

Ratio interpretation in combination with rate interpretation (traditional decline analysis) can increase confidence in the forecasts. In exponential or harmonic rate decline, slope dependencies are often observed between the rate and ratio trends. By plotting a forecast on both rate and ratio data, the slope dependencies can be used to match historical data on both the rate and ratio trends. These interpretations are less likely to show personal bias, as the forecast would only look reasonable if it matched both trends. Exponential decline is best analyzed on a semi-log plot of a water-oil ratio or a water-oil ratio +1 vs. time. Harmonic decline is best analyzed on a semi-log plot of a water-oil ratio or a water-oil ratio +1 vs. cumulative oil. The plot below shows slope dependence (the rate slope is the inverse of the ratio slope) between the oil rate and the water-oil ratio +1, while the total fluid rate (oil + water) is constant.



The WOR and WOR +1 are often used interchangeably. The advantage of WOR +1 in some situations is that periods with zero water production can be plotted. In some cases, the ratio trend appears more linear on WOR or WOR +1. It could be that the WOR behaves linearly when water rates are constant, and WOR +1 behaves linearly when total fluid rates are constant. This may guide you in determining which plot to select, but both should be considered uncertain. To create the forecast, a linear trend is placed on the WOR or WOR +1 semi-log plot, and a maximum WOR or water cut is used to truncate the forecast. An oil rate forecast is calculated by combining the ratio forecast with a total fluid rate.



Water-oil ratio forecasting provides the most useful result in water drive or waterflood scenarios (for example, scenarios with high water production). However, linearizing the data removes the diagnostic aspects that may be desired for these reservoirs and production scenarios. Similar to decline forecasts, the trends created with WOR plots should be considered under constant operating conditions. Changing conditions, such as infill drilling or recompletions, often appear as changing the slope in the WOR trend.

Calculations & correlations

Calculations and correlations include the following:

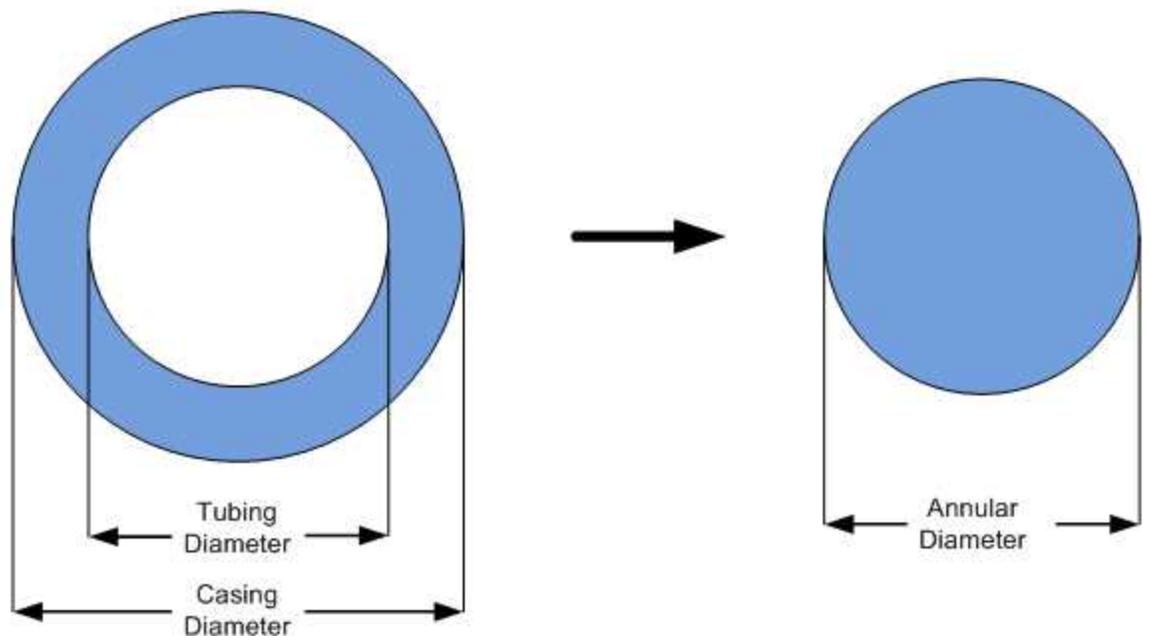
- Annular diameters
- Liquid lift calculations
- Relative permeability correlations
- Artificial lift
- Gas calculations & correlations
- Water correlations
- Average reservoir pres-
- Oil correlations

- sure calculations
- Capillary correlations
- Flow rate calculations
- Geomechanical correlations
- Pressure loss calculations
- Pressure loss calculations in multilayer wells
- Recombination

Annular diameters

Pressure loss calculations for an annulus flow path require some extra steps to complete because the standard cylindrical tube model cannot be directly applied. Instead, the annular space is converted into a single cylindrical tube through the use of one of the following methods:

- Equivalent diameter method
- Hydraulic (or wetted) diameter method



Equivalent diameter

With the equivalent diameter solution, the objective is to find a single tube that has the same cross-sectional area as the annulus. While this method seems logical at first glance, it does not

account for frictional differences on both pipe walls (that is, the inside wall of the casing and the outside wall of the tubing).

$$\textit{Equivalent Diameter} = \sqrt{D_2^2 - D_1^2}$$

where:

- D_1 = outer diameter of the tubing
- D_2 = inner diameter of the casing

Hydraulic (wetted) diameter

With the hydraulic diameter solution, the objective again is to find a diameter for a single tube that represents the annulus, but also accounts for the extra friction that annular flow would experience.

$$\textit{Hydraulic Diameter} = \frac{4(\textit{Area})}{\textit{WettedPerimeter}}$$

$$\textit{Hydraulic Diameter} = \frac{4\left(\frac{\pi D_2^2}{4} - \frac{\pi D_1^2}{4}\right)}{\pi(D_2 + D_1)}$$

this simplifies down to $\textit{Hydraulic Diameter} = D_2 - D_1$

where:

- D_1 = outer diameter of the tubing
- D_2 = inner diameter of the casing

Average reservoir pressure calculations

Average reservoir pressure at the end of the production period is calculated for oil and gas reservoirs provided that the original oil-in-place and original gas-in-place are known. The calculated average reservoir pressure value is reported under the calculations part for all the applicable typecurves.

Oil wells

Using the definition of compressibility, we can write:

$$c_t = \frac{1}{N} \cdot \frac{N_p}{(p_i - \bar{p})}$$

The above equation can be changed to:

$$\bar{p} = p_i - \frac{N_p}{c_t N}$$

Gas wells

For a gas reservoir, we can write:

$$\frac{\bar{p}}{Z} = \frac{p_i}{Z_i} \left(1 - \frac{G_p}{G} \right)$$

Capillary correlations

Capillary pressure correlations

Analytical: Developed based on theory and generally applicable for calculating capillary pressures.

$$p_{cow} = p_{cgw} = a_o + a_1 (1 - S_{wn}) + a_2 (1 - S_{wn})^2 + a_3 (1 - S_{wn})^3$$

$$S_{wn} = \frac{(S_w - S_{wirr})}{(1 - S_{wirr})}$$

$$p_{cog} = a_o + a_1 S_{gn} + a_2 S_{gn}^2 + a_3 S_{gn}^3$$

$$S_{gn} = \frac{S_g}{(1 - S_{org})}$$

where: a_0 = Coefficient 0, a_1 = Coefficient 1, ...

Brooks-Corey: An empirical approach to calculate capillary pressures and works satisfactorily in many cases. It requires residual wetting-phase saturation. Uses a lithology factor that allows the correlations to be generalized to any lithology.

$$p_{cow} = p_{cgw} = C_w (S_{wn})^{-A_w}$$

$$A_w = 1/\lambda$$

$$S_{wn} = \frac{(S_w - S_{wirr})}{(1 - S_{wirr})} \text{ for drainage}$$

$$S_{wn} = \frac{(S_w - S_{wirr})}{(1 - S_{wirr} - S_{orw})} \text{ for imbibition}$$

$$A_o = 1/\lambda$$

$$S_{on} = \frac{(S_o - S_{org})}{(1 - S_{org})}$$

Custom Table: Allows you to enter laboratory measurements for capillary pressure values.

Analytical

Water-oil system

$$p_{cow} = Coeff0 + Coeff1(1 - S_{wn}) + Coeff2(1 - S_{wn})^2 + Coeff3(1 - S_{wn})^3$$

$$S_{wn} = \frac{S_w - S_{wirr}}{1 - S_{wirr}}$$

where:

Coeff0 = capillary pressure coefficient 0

Coeff1 = capillary pressure coefficient 1

Coeff2 = capillary pressure coefficient 2

Coeff3 = capillary pressure coefficient 3

Gas-oil system

$$p_{cgo} = Coeff0 + Coeff1(1 - S_{gn}) + Coeff2(1 - S_{gn})^2 + Coeff3(1 - S_{gn})^3$$

$$S_{gn} = \frac{S_g}{1 - S_{org}}$$

where:

Coeff0 = capillary pressure coefficient 0

Coeff1 = capillary pressure coefficient 1

Coeff2 = capillary pressure coefficient 2

Coeff3 = capillary pressure coefficient 3

Brooks Corey

The Brooks Corey model is widely accepted to calculate capillary pressure for relative permeability calculations. This model is a modified representation of Corey's model and represents the capillary pressure in a more general form.

Water-oil system

$$p_{cow} = (p_{ce})_{ow}^{-\frac{1}{\lambda_{ow}}}$$

$$S_{wn} = \frac{S_w - S_{wirr}}{1 - S_{wirr}}$$

where:

$(p_{ce})_{ow}$ = oil-water pore entry capillary pressure

λ_{ow} = oil-water pore size distribution index

Gas-oil system

$$p_{cgo} = (p_{ce})_{go}^{-\frac{1}{\lambda_{go}}}$$

$$S_{on} = \frac{S_o - S_{org}}{1 - S_{org}}$$

where:

$(p_{ce})_{go}$ = gas-oil pore entry capillary pressure

λ_{go} = gas-oil pore size distribution index

Flow rate calculations

When viewing production data and when using that data to generate forecasts of future production, it is critical that the method used to calculate the rates be known, understood, and used properly. Four commonly used terms used in this regard are "operated-day rate" (op-day), "calendar-day rate" (cal-day), "time on-production", and "load factor".

Note: The term "injection" can be substituted in all the definitions below where "production" is used.

Operated-day rate

Operated-day rate is defined as the volume of fluid produced or forecast over a period of time divided by the actual on-time during the period in days. For example, if a well produced 300 barrels of oil in a 30 day month, but was only actually producing for 15 days, then:

$$\text{Operated-Day Rate} = 300 \text{ Bbls} / 15 \text{ days} = 20 \text{ Bbls} / \text{day}$$

Calendar-day rate

Calendar-day rate is defined as the volume of fluid produced or forecast over a period of time divided by the number of days in the period, regardless of actual on-time. For example, if a well produced 300 barrels of oil in a 30-day month, but was only actually producing for 15 days, then:

$$\text{Calendar-Day Rate} = 300 \text{ Bbls} / 30 \text{ days} = 10 \text{ Bbls} / \text{day}$$

Time on-production

Time on-production is defined as the period of time a well is actually producing. It is typically expressed in hours or days.

Load factor

Load factor is defined as the ratio of the actual on-time and the period time. For example, if a well produced for 15 days in a 30-day period, then its load factor expressed as a percentage would be:

$$15/30 * 100 = 50\%$$

Gas calculations & correlations

Gas correlations

There are three types of gas correlations: pressure volume temperature (PVT), viscosity, and gas type.

PVT

B.W.R. (Table): The Benedict-Webb-Rubin is an empirical relationship that predicts the state of liquids and gases. Tables were developed for approximately fifty substances, mostly hydrocarbons that related gas density, formation volume factor, and temperature to pressure.

B.W.R. (8-constant): The Benedict-Webb-Rubin (8-constant) equation of state developed a set of generalized coefficients in order to permit widespread application to all types of gases.

B.W.R. (11-constant): The Benedict-Webb-Rubin (11-constant) equation of state is a further refined method to predict the state of liquids and gases. Used for all types of gases, it uses 11 empirical constants to achieve a more accurate interpolation of the data.

AGA8 Detail: Calculates the Z-factor based on the physical chemistry of the gas components at specified temperatures and pressures. It can be used when the exact composition (fraction mole percents) of the gas is available.

Carbon Dioxide: The Carbon Dioxide tables are for computing the Z factor for 100% CO₂ content.

Nitrogen: The Nitrogen tables are for computing the Z factor for 100% N₂ content.

Hydrogen Sulfide: The Hydrogen Sulfide tables are for computing the Z factor for 100% H₂S content.

Custom Table: Allows you to enter laboratory measurements for the gas Z-factor or formation volume factor. The Z factor is calculated from the formation volume factor or vice versa. Gas compressibility is subsequently calculated from these two values.

Viscosity

Carr et al: Developed to predict the viscosity of gas hydrocarbon mixtures for temperatures between 32°F and 400°F and pressures up to 12,000 psi. Applies to both sweet and sour gas and is designed to handle non-hydrocarbon components (CO₂, H₂S, N₂) in concentrations of up to 15% each.

Lee, Gonzalez, Eakin: Applies to sweet gas and does not account for the presence of non-hydrocarbon components. Applicable for pressure ranges of 100 - 8,000 psi and temperatures between 100°F - 340°F. Less accurate for gases with specific gravity above 1.0.

Optimized Lee et al: Developed using the Lee, Gonzalez, and Eakin method, but uses a optimized temperature history to achieve more accurate results, thus resulting in different coefficients in the equations. Less than 5% difference in extreme cases from original correlations.

Lucas et al: Uses the method of corresponding states to calculate gas viscosity. Better suited for higher density gases at lower pressures.

Custom Table: Choosing this correlation allows you to enter custom gas viscosity values from laboratory measurements.

Gas type

Selecting wet or dry gas changes the results obtained from gas correlations, as different coefficients have been developed for these gas types. The Liquid-rich Gas option allows for the recombination of gas and condensate into a single gas stream.

Ovalle et al.'s correlation for R_v

Ovalle et al.'s correlation is based solely on commonly available field data. Required field data is as follows: the initial producing gas / condensate ratio from the first separator, the initial stock tank liquid gravity in API, the specific gravity of initial reservoir gas, and reservoir temperature. This correlation does not need require the dew point pressure to calculate the "R_v" curve vs. pressure.

$$R_v = \exp[3.684 + 0.61967 \times Z + 0.015359 \times Z^2]$$

$$Z = \sum_{n=0}^4 Z_n$$

n	V _{arn}	C _{0n}	C _{1n}	C _{2n}	C _{3n}	C _{4n}
1	ln P, psi	20.809	-6.7095	0.5136	0	0
2	API _d	11.175	-1.2965	0.042311	-0.0005438	2.49E-06
3	γ_{gRD}	-13.365	27.652	-18.598	4.3658	0
4	TR, °F	-1.5309	0.0058453	1.40E-06	0	0

API _d	Gravity of stock-tank liquid, oAPI, determined when P ≥ P _d
P	Pressure, psi
γ_{gRd}	Reservoir gas specific gravity at P ≥ P _d (This value is the recombined gas specific gravity)
TR	Reservoir temperature, °F
RV	Vaporized oil ratio, Stb / MMscf

Calculation of the vaporized oil ratio

The vaporized oil ratio (R_v) can be calculated from the liquid drop-out (V_L / V_{sat}) measured in the lab.

$$R_v = \frac{(V_L/V_{sat})B_{gd,sat} - B_oCGR_i}{(V_L/V_{sat})B_{gd,sat}R_s - B_o}$$

where

(V_L/V_{sat}) : the liquid drop-out of a liquid-rich gas, meaning the retrograde liquid volume at any pressure (below the dew point pressure) and reservoir temperature relative to the volume of the gas sample at the dew point pressure and reservoir temperature.

$B_{gd,sat}$: the dry gas formation factor at the dew point pressure (saturation pressure)

Geomechanical correlations

There are two types of geomechanical correlations: permeability and compressibility.

Permeability correlations

Yilmaz and Nur: A generic correlation suitable for extremely low permeability reservoirs.

Dobrynin: A more detailed correlation designed for over-pressurized reservoirs that require porosity as an input. Valid in the pressure range of 0 – 20,000 psi.

Custom Table: Allows you to enter laboratory measurements for the permeability ratio.

Compressibility correlations

Dobrynin: A more detailed correlation designed for over-pressurized reservoirs that require porosity as an input. Valid in the pressure range of 0 – 20,000 psi.

Custom Table: Allows you to enter laboratory measurements for formation compressibility. The formation compressibility ratio is calculated using the formation compressibility entered for each pressure divided by the initial formation compressibility coming from the basic reservoir properties.

Liquid lift calculations

Liquid lift calculations use the Turner correlation, which determines the minimum gas velocity required to continuously lift liquids. The intent of these calculations is to determine the minimum

gas rate for a given wellbore configuration and pressure, below which liquid loading problems may start to occur.

The Turner correlation is as follows:

$$v_g \left(\textit{water} \right) = \frac{5.62 (67 - kp)^{0.25}}{(kp)^{0.5}}$$

$$v_g \left(\textit{Oil / Condensate} \right) = \frac{4.02 (45 - kp)^{0.25}}{(kp)^{0.5}}$$

$$k = \frac{2.693 G}{Z T}$$

$$q_g = \frac{3.06 p v_g A}{Z T}$$

Oil correlations

Oil / condensate correlations

Oil condensate PVT correlations are described below.

PVT

Vasquez and Beggs: Developed from data obtained from fields all over the world and generally applicable for all oil types. Covers a wide range of pressures, temperatures, and oil properties.

Al-Marhoun: Developed for Saudi Arabian oils. Valid for all types of gas-oil mixtures ranging from 14 - 45 °American Petroleum Institute (API) gravity.

De Ghetto et al: Developed for heavy oils (10 < °API < 22.3) and extra-heavy oils (°API < 10) from the Mediterranean Basin, Africa, and the Persian Gulf. Requires separator pressure and temperature.

Glaso: Developed for North Sea oils and it is suitable for oil mixtures ranging from 22-48 °API. Valid for all types of oil and gas mixtures after correcting for non-hydrocarbons in the surface gases and the paraffinicity of the oil.

Hanafy et al: Developed for Egyptian oils gathered from the Gulf of Suez, Western Desert, and Sinai regions. Independent of oil gravity and reservoir temperature. Although authors claim that the correlations are applicable to a wide range of crude oils ranging from heavy to volatile oils (14.3 – 47 °API), it appears to be more applicable for light oils.

Petrosky and Farshad: Developed for Gulf of Mexico oils gathered from offshore regions in Texas and Louisiana. Applicable for oil mixtures ranging from 16 - 45 °API. Provides improved results for the Gulf of Mexico oils compared to Standing, Vasquez and Beggs, Glaso, and Al-Marhoun correlations.

Standing: Developed for California oils. Applicable for oil mixtures ranging from 16 - 64 °API.

Velarde et al: Developed for black oils, applicable for oil mixtures ranging from 12 - 55 °API.

Constant Properties: Allows you to enter values for oil compressibility, the solution gas-oil ratio, and the oil formation volume factor at initial reservoir conditions.

Custom Table: Allows you to enter laboratory measurements for oil compressibility, the solution gas-oil ratio, and the oil formation volume factor.

Viscosity

Beggs and Robinson: Developed from data obtained from fields all over the world and generally applicable for all oil types. Covers a wide range of pressures, temperatures, and oil properties.

De Ghetto et al: Developed for heavy oils ($10 < \text{°API} < 22.3$) and extra-heavy oils ($\text{°API} < 10$) from the Mediterranean Basin, Africa, and the Persian Gulf. Requires separator pressure and temperature.

Hanafy et al: Developed for Egyptian oils gathered from the Gulf of Suez, Western Desert, and Sinai regions. Independent of oil gravity and reservoir temperature. Although the authors claim that the correlations are applicable to a wide range of crude oils ranging from heavy to volatile oils (14.3 – 47 °API), it appears to be more applicable for light oils.

Khan et al: Developed using oil samples collected from Saudi Arabian reservoirs. Gives more accurate predictions for Saudi Arabian oils, compared to the Beggs and Robinson.

Ng and Egbogah: This correlation contains two methods for calculating dead oil viscosity using a modified Beggs and Robinson viscosity correlation and a correlation that uses the pour-point temperature, which is the lowest temperature at which the oil is observed to flow when cooled. The

purpose of introducing the pour-point temperature into the correlation is to reflect the chemical composition of crude oil into the viscosity correlation. To obtain the viscosity for live oils, the dead oil correlations are used with the Beggs and Robinson viscosity correlation. This correlation is applicable for oil mixtures ranging from 5 - 58 °API.

Constant Properties: Allows you to enter the value for oil viscosity at initial reservoir conditions.

Custom Table: Allows you to enter laboratory measurements for oil viscosity.

Vasquez and Beggs (generally applicable)

Vasquez and Beggs is a generally applicable correlation containing equations for the solution gas oil ratio, oil formation volume factor, and oil compressibility. The correlation was developed from data obtained from over 600 laboratory pressure volume temperature (PVT) analyses gathered from fields all over the world. The data used in the development of the correlation covers a wide range of pressures, temperatures, and oil properties. The correlation divides the data into two groups: one for oil gravity over 30°API and one at and below 30°API.

Note: This is the default setting for oil correlations.

Bubble point pressure

$$p_{bp} = \left(\frac{R_{so}}{C_1 G e^{C_3 \left(\frac{\gamma_o}{T+460} \right)}} \right)^{\frac{1}{C_2}}$$

Coefficient	$\gamma_o \leq 30^\circ$ API	$\gamma_o > 30^\circ$ API
C ₁	0.0362	0.0178
C ₂	1.0937	1.1870
C ₃	25.7240	23.9310

Solution gas oil ratio

$$R_{so} = C_1 G p^{C_2} \cdot e^{C_3 \left(\frac{\gamma_o}{T+460} \right)}$$

Oil formation volume factor (FVF) – saturated

$$B_o = 1 + A_1 R_{so} + A_2 (T - 60) \left(\frac{\gamma_o}{G}\right) + A_3 R_{so} (T - 60) \left(\frac{\gamma_o}{G}\right)$$

Coefficient	$\gamma_o \leq 30^\circ$ API	$\gamma_o > 30^\circ$ API
A ₁	4.677E-04	4.670E-04
A ₂	1.751E-05	1.100E-05
A ₃	-1.811E-08	1.337E-09

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{c_o (p_{bp} - p)}$$

where B_{ob} is the formation volume factor at the bubble point pressure

Compressibility – saturated

$$c_o = \frac{-1433 + 5 R_{sob} + 17.2T - 1180G + 12.61 \gamma_o}{10^5 p} + \frac{B_g}{B_o} \cdot \frac{dR_{so}}{dp} \cdot \frac{1}{5.615}$$

where R_{sob} is the solution gas-oil ratio at the bubble point pressure

Compressibility – undersaturated

$$c_o = \frac{-1433 + 5R_{sob} + 17.2T - 1180G + 12.61 \gamma_o}{10^5 p}$$

Al-Marhoun (Middle East oil)

The Al-Marhoun correlation contains equations for estimating bubble point pressure, solution gas oil ratio, and oil formation volume factor for Middle East oils. 75 bottomhole fluid samples from 62 reservoirs in the Middle East were used in the development of these correlations. The author claims that the correlations should be valid for all types of gas-oil mixtures that share similar

properties as those used in the derivation. According to the author, the average errors and standard deviations were lower with the Al-Marhoun correlation than with the Standing and Glaso correlations for Middle Eastern crude oils. Note that temperature is measured in Rankine.

Bubble point pressure

$$p_{bp} = -64.138910 + 0.702362 \cdot 10^{-2} \cdot x - 2.278475 \cdot 10^{-9} \cdot x^2$$

$$x = R_s^{0.722569} \cdot \gamma_g^{-1.879109} \cdot \gamma_o^{3.04659} \cdot T^{1.302347}$$

Solution gas oil ratio

$$R_s = \left(\frac{x}{\gamma_g^{-1.879109} \cdot \gamma_o^{3.04659} \cdot T^{1.302347}} \right)^{\frac{1}{0.722569}}$$

$$x = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a}$$

where:

$$a = -2.278475 \cdot 10^{-9}$$

$$b = 7.02362 \cdot 10^{-3}$$

$$c = -64.13891 - p$$

Oil FVF – saturated

$$B_o = 0.574095 + 7.723532 \cdot 10^{-4} \cdot T + 2.454005 \cdot 10^{-3} \cdot y + 3.727676 \cdot 10^{-5} \cdot y^2$$

$$y = R_s^{0.501538} \cdot \gamma_g^{-0.145526} \cdot \gamma_o^{-5.220726}$$

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{(c_o(p_b - p))}$$

The oil compressibility used in this equation is obtained from the Vasquez and Beggs correlation.

Beggs and Robinson

Beggs and Robinson developed an empirical correlation for determining the viscosity of dead oil. The correlation originated from analyzing 460 dead oil viscosity measurements. The dataset from which the results were obtained ranged from 16°API to 58°API and 70°F to 295°F. The correlation tends to overstate the viscosity of the crude oil when dealing in temperature ranges below 100°F to 150°F.

Viscosity

$$\mu_{od} = 10^x - 1$$

where:

$$x = y T^{-1.163}$$

$$y = 10^z$$

$$z = 3.0324 - 0.02023 G$$

De Ghetto et al. (heavy and extra-heavy oils)

The De Ghetto et al. correlation contains modified PVT correlations for estimating bubble point pressure, solution gas oil ratio, oil formation volume factor (FVF), oil compressibility, and oil viscosity for heavy ($10^\circ < \text{API} < 22.3^\circ$) and extra-heavy oils ($\text{API} < 10^\circ$). The oils used for developing the correlation came from reservoir fluid samples taken from the Mediterranean Basin, Africa, and the Persian Gulf. When comparing published correlations, De Ghetto et al. decided that the Vasquez and Beggs correlation estimated the oil formation volume factor with minimal error, and therefore no further modification was needed. Note that in contrast with other correlations, the De Ghetto et al. correlation requires the pressure and temperature at the separator.

Heavy oils ($10^\circ < \text{API} < 22.3^\circ$)

Bubble point pressure

$$p_b = \left(\frac{56.434 \cdot R_s}{\gamma_g(p_{sp}) \cdot 10^{10.9267 \left(\frac{\gamma_{API}}{T+459.67} \right)}} \right)^{\frac{1}{1.2057}}$$

$$\gamma_g(p_{sp}) = \gamma_g \left(1 + 0.5912 \cdot \gamma_{API} \cdot T_{sp} \cdot \log \left(\frac{p_{sp}}{114.7} \right) \cdot 10^{-4} \right)$$

Solution gas oil ratio

$$R_s = \frac{\gamma_g(p_{sp}) \cdot p^{1.2057}}{56.434} \cdot 10^{10.9267} \cdot \left(\frac{\gamma_{API}}{T + 459.67} \right)$$

Oil FVF – saturated

$$B_o = 1 + A_1 R_s + A_2 (T - 60) \left(\frac{\gamma_{API}}{\gamma_g} \right) + A_3 R_s (T - 60) \left(\frac{\gamma_{API}}{\gamma_g} \right)$$

where:

$A_1, A_2,$ and A_3 are Vasquez and Beggs constants for $API \leq 30^\circ$:

$$A_1 = 4.677 \cdot 10^{-4}$$

$$A_2 = 1.751 \cdot 10^{-5}$$

$$A_3 = -1.811 \cdot 10^{-8}$$

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{(c_o(p_b - p))}$$

Compressibility – saturated

$$c_o = \frac{-2841.8 + 2.9646 \cdot R_{sb} + 25.5439 \cdot T - 1230.5 \cdot \gamma_g(p_{sp}) + 41.91 \cdot \gamma_{API}}{p \cdot 10^5} + \frac{B_g}{5.6145835 \cdot B_o} \cdot \frac{dB_g}{dp}$$

Compressibility – undersaturated

$$c_o = \frac{-2841.8 + 2.9646 \cdot R_{sb} + 25.5439 \cdot T - 1230.5 \cdot \gamma_g(p_{sp}) + 41.91 \cdot \gamma_{API}}{p \cdot 10^5}$$

Viscosity – dead oil

$$\log(\mu_{od} + 1) = 2.06492 - 0.0179 \cdot \gamma_{API} - 0.70226 \cdot \log(T)$$

Viscosity – saturated

$$\mu_{os} = -0.6311 + 1.078 \cdot x - 0.003653 \cdot x^2$$

$$x = \left(0.2478 + 0.6144 \cdot 10^{-0.000845R_s}\right) \cdot \mu_{od}^{(0.4731+0.5158)}$$

$$y = 10^{-0.00081 R_s}$$

Viscosity – undersaturated

$$\mu_o = 0.9886 \cdot \mu_{os} + 0.002763(p - p_b) \left(-0.01153 \cdot \mu_{os}^{1.7933} + 0.0316 \cdot 0.0316 \cdot \mu_{os}^{1.5939}\right)$$

Extra heavy oils (API < 10°)

Bubble point pressure

$$p_b = \left(\frac{R_s}{\gamma_g}\right)^{\frac{1}{1.1128}} \cdot \frac{10.7025}{10^{(0.0169 \cdot \gamma_{API} - 0.00156T)}}$$

Solution gas oil ratio

$$R_s = \gamma_g \left(\frac{p}{10.7025} \cdot 10^{(0.0169 \cdot \gamma_{API} - 0.00156T)}\right)^{1.1128}$$

Oil FVF – saturated

$$B_o = 1 + A_1 R_s + A_2 (T - 60) \left(\frac{\gamma_{API}}{\gamma_g}\right) + A_3 R_s (T - 60) \left(\frac{\gamma_{API}}{\gamma_g}\right)$$

where:

A_1 , A_2 , and A_3 are Vasquez and Beggs constants for $API \leq 30^\circ$:

$$A_1 = 4.677 \cdot 10^{-4}$$

$$A_2 = 1.751 \cdot 10^{-5}$$

$$A_3 = -1.811 \cdot 10^{-8}$$

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{(c_o(p_b - p))}$$

Compressibility – saturated

$$c_o = \frac{-889.6 + 3.1374 \cdot R_{sb} + 20 \cdot T - 627.3 \cdot \gamma_g(p_{sp}) - 81.4476 \cdot \gamma_{API}}{p \cdot 10^5} + \frac{B_g}{5.6145835 \cdot B_o} \cdot \frac{dR_s}{dp}$$

Compressibility – undersaturated

$$c_o = \frac{-889.6 + 3.1374 \cdot R_{sb} + 20 \cdot T - 627.3 \cdot \gamma_g(p_{sp}) - 81.4476 \cdot \gamma_{API}}{p \cdot 10^5}$$

Viscosity – dead oil

$$\log(\mu_{od} + 1) = 1.090296 - 0.012619 \cdot \gamma_{API} - 0.61748 \cdot \log(T)$$

Viscosity – saturated

$$\mu_{os} = 2.3945 + 0.8927 \cdot x + 0.001567 \cdot x^2$$

$$x = \left(-0.0335 + 1.0785 \cdot 10^{-0.000845 R_s} \right) \cdot \mu_{od}^{(0.5798 + 0.3432y)}$$

$$y = 10^{-0.00081 R_s}$$

Viscosity – undersaturated

$$\mu_o = \mu_{os} - \left(1 - \frac{p}{p_b} \right) \left(\frac{10^{-2.19} \cdot \mu_{od}^{1.055} \cdot p_b^{0.3132}}{10^{0.0099 \gamma_o}} \right)$$

Glaso (North Sea oil)

The Glaso correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, and the oil formation volume factor for North Sea oils. The author claims that the correlation should be valid for all types of oil and gas mixtures after correcting for non-hydrocarbons in the surface gases and the paraffinicity of the oil. According to the author, the correlation more accurately predicts the oil properties of North Sea oils than the Standing correlation.

Bubble point pressure

$$\log(p_b) = 1.7669 + 1.7447 \cdot \log(x) - 0.30218 \cdot \log(x)^2$$

$$p_b = 10^{\log(p_b)}$$

$$x = \left(\frac{R_s}{\gamma_g} \right)^{0.816} \frac{T^{0.172}}{\gamma_{API}^{0.989}}$$

Solution gas oil ratio

$$R_s = \left(\frac{x \cdot \gamma_{API}^{0.989}}{T^{0.172}} \right)^{\frac{1}{0.816}} \gamma_g$$

$$\log(x) = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a}$$

where:

$$x = 10^{\log(x)}$$

$$a = -0.30218$$

$$b = 1.7447$$

$$c = 1.7669 - \log(p)$$

Oil FVF – saturated

$$\log(B_o - 1) = -6.58511 + 2.91329 \cdot \log(y) - 0.27683 \cdot \log(y)^2$$

$$y = R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.526} + 0.968 T$$

Oil FVF – undersaturated

$$B_o = B_{ob} \cdot e^{(c_o(p_b - p))}$$

Note: The oil compressibility used in this equation is obtained from the Vasquez and Beggs correlation.

Hanafy et al. (Egyptian oil)

The Hanafy et al. correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, oil formation volume factor, oil compressibility, oil viscosity, and oil density for Egyptian oils. The compressibility correlation assumes constant compressibility after the bubble point. This correlation is independent of oil gravity and reservoir temperature. The pressure volume temperature (PVT) data used in the derivation of the correlations was gathered from the Gulf of Suez, Western Desert, and Sinai regions. The authors claim that the correlations can be used to estimate oil properties for a wide range of crude oils ranging from heavy to volatile oils. However, our observations are that it appears to be closer to the properties of light oils.

Bubble point pressure

$$p_b = 3.205 \cdot R_s + 157.27$$

Solution gas oil ratio

$$R_s = -49.069 + 0.312p$$

$R_s = 0$ when $p \leq 157.28$

Oil FVF – saturated

$$B_o = 0.0006 \cdot R_s + 1.079$$

Oil FVF – undersaturated

$$B_o = B_{ob} e^{(c_o (p_b - p))}$$

Density – saturated

$$\rho_o = \left(2.366 - \left(\frac{1.358}{B_o} \right) \right)^{-1}$$

Density – undersaturated

$$\rho_o = \rho_{ob} e^{(c_o (p - p_b))}$$

Compressibility – saturated

$$c_o = e^{\left(\frac{2.582}{\rho_o} - 0.99 \right)} \cdot 10^{-6} + \frac{B_g}{5.6145835 \cdot B_o} \cdot \frac{dR_s}{dp}$$

Compressibility – undersaturated

$$c_o = e^{\left(\left(\frac{2.582}{\rho_{ob}} \right) - 0.99 \right)} \cdot 10^{-6}$$

Oil viscosity

$$\mu_o = e^{(7.296 \cdot \rho_o^3 - 3.095)}$$

Khan et al. (Saudi Arabian oil)

The Khan et al. correlation contains equations for estimating oil viscosity at, above, and below the bubble point for Saudi Arabian oils. The study used data from 75 sandface samples, which were taken from 62 Saudi Arabian reservoirs. The authors claim that this correlation gives the most accurate predictions for Saudi Arabian crude oils, as compared to the Beggs and Robinson, Beal, and Chew and Connally correlations.

Oil viscosity

$$p = p_b$$

$$\mu_{ob} = \frac{0.09 \sqrt{\gamma_g}}{\sqrt[3]{R_s \cdot \theta_r^{4.5} (1 - \gamma_0)^3}}$$

where:

$$\theta_r = \frac{T + 459.67}{459.67} = \textit{relative temperature}$$

$p > p_b$

$$\mu_o = \mu_{ob} e^{(9.6 \cdot 10^{-5} (p - p_b))}$$

$p < p_b$

$$\mu_{os} = \mu_{ob} \left(\frac{p}{p_b}\right)^{-0.14} e^{(-2.5 \cdot 10^{-4} (p - p_b))}$$

Ng and Egbogah

The Ng and Egbogah correlation contains two methods for calculating dead oil viscosity using a modified Beggs and Robinson viscosity correlation and a correlation that uses the pour point temperature. Pour point temperature is the lowest temperature at which the oil is observed to flow when cooled and examined under conditions prescribed in ASTM D97. The purpose of introducing the pour point temperature into the correlation is to reflect the chemical composition of crude oil into the viscosity correlation. To obtain the viscosity for live oils, the dead oil correlations are used with the Beggs and Robinson viscosity correlation. The data used to derive the correlations was taken from the Reservoir Fluids Analysis Laboratory of AGAT Engineering Ltd., using a total of 394 oil systems.

Dead oil

$$\log(\mu_{od} + 1) = -1.7095 - 0.0087917 \cdot T_{pp} + 2.7523 \cdot \gamma_o + (-1.2943 + 0.0033214 \cdot T_{pp} + 0.9581957 \cdot \gamma_o) \cdot \log(T - T_{pp})$$

$$-50^\circ\text{C} < T_{pp} < 15^\circ\text{C}$$

Live oil – saturated

$$\mu_{os} = x \cdot \mu_{od}^y$$

$$x = 10.715 (R_s + 100)^{-0.515}$$

$$y = 5.44 (R_s + 150)^{-0.338}$$

where μ_{od} is defined using the modified Beggs and Robinson correlation.

$$\log(\mu_{od} + 1) = 1.8653 - 0.025086 \cdot \gamma_o - 0.5644 \cdot \log(T)$$

Live oil - undersaturated

$$\mu_o = \mu_{ob} \left(\frac{p}{p_b} \right)^x$$

$$x = 2.6p^{1.187} e^{(-11.513 - 8.98 \cdot 10^{-5}p)}$$

Petrosky and Farshad (Gulf of Mexico)

The Petrosky and Farshad correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, oil formation volume factor, and oil compressibility for Gulf of Mexico oils. The correlation was developed using fluid samples taken from offshore regions in Texas and Louisiana (Galveston Island eastward through Main Pass). The authors claim that these correlations provide improved results over other correlations for the Gulf of Mexico, including those published by Standing, Vasquez and Beggs, Glaso, and Al-Marhoun.

Bubble point pressure

$$p_b = 112.727 \left(\frac{R_s^{0.5774}}{\gamma_g^{0.8439}} \cdot 10^x - 12.34 \right)$$

where:

$$x = 4.561 \cdot 10^{-5} \cdot T^{1.3911} - 7.916 \cdot 10^{-4} \cdot \gamma_{API}^{1.541}$$

Solution gas oil ratio

$$R_s = \left(\left(\frac{p}{112.727} + 12.34 \right) \cdot \gamma_g^{0.8439} \cdot 10^x \right)^{1.73184}$$

where:

$$x = 7.916 \cdot 10^{-4} \cdot \gamma_{API}^{1.541} - 4.561 \cdot 10^{-5} \cdot T^{1.3911}$$

Oil FVF – saturated

$$B_o = 1.0113 + 7.2046 \cdot 10^{-5} \cdot \left(R_s^{0.3738} \left(\frac{\gamma_g^{0.2914}}{\gamma_o^{0.6265}} \right) + 0.24626 \cdot T^{0.5371} \right)^{3.0936}$$

Oil FVF – undersaturated

$$B_o = B_{ob} e^{(c_o (p_b - p))}$$

Compressibility – saturated

$$c_o = 1.705 \cdot 10^{-7} \cdot R_{sb}^{0.69357} \cdot \gamma_g^{0.1885} \cdot \gamma_{API}^{0.3272} \cdot T^{0.6729} \cdot p^{-0.5906} + \frac{B_g}{5.6145835 \cdot B_o} \cdot \frac{dR_s}{dp}$$

Compressibility – undersaturated

$$c_o = 1.705 \cdot 10^{-7} \cdot R_{sb}^{0.69357} \cdot \gamma_g^{0.1885} \cdot \gamma_{API}^{0.3272} \cdot T^{0.6729} \cdot p^{-0.5906}$$

where $2.464 \cdot 10^{-5} < c_o < 3.507 \cdot 10^{-5}$

Standing (California oil)

The Standing correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, and the oil formation volume factor for California oils. There were 105 experimentally determined data points on 22 different oil-gas mixtures from California used in the development of the correlations.

Bubble point pressure

$$p_b = 18.2 \left(\left(\frac{R_s}{G} \right)^{0.83} \cdot \frac{10^{0.00091 T}}{10^{0.0125 \gamma_{API}}} - 1.4 \right)$$

Solution gas oil ratio

$$R_s = \left(\left(\frac{p}{18.2} + 1.4 \right) \cdot \frac{10^{0.0125 \gamma_{API}}}{10^{0.00091 T}} \right)^{\frac{1}{0.83}} \cdot G$$

Oil FVF – saturated

$$B_o = 0.972 + 1.47 \cdot 10^{-4} \left(R_s \left(\frac{G}{\gamma_o} \right)^{0.5} + 1.25 \cdot T \right)^{1.175}$$

Oil FVF – undersaturated

$$B_o = B_{ob} e^{(c_o (p_b - p))}$$

The oil compressibility used in this equation is obtained from the Vasquez and Beggs correlation.

Velarde et al. (reduced variable approach)

The Velarde et al. correlation contains equations for estimating the bubble point pressure, solution gas oil ratio, and the oil formation volume factor. The bubble point pressure correlation was based on 728 datasets. The solution gas oil ratio was based on 2097 datasets.

Bubble point pressure

$$p_b = 1091.47 \left(R_{sb}^{0.081465} \cdot \gamma_g^{-0.161488} \cdot 10^x - 0.740152 \right)^{5.354891}$$

$$x = 0.013098 \cdot T^{0.282372} - 8.2 \cdot 10^{-6} \cdot \gamma_{API}^{2.176124}$$

Solution gas oil ratio ($p = p_b$)

$$R_s = \left(\frac{\left(\frac{p_b}{1091.47} \right)^{\frac{1}{5.354891}} + 0.740152}{\gamma_g^{-0.161488} \cdot 10^x} \right)^{\frac{1}{0.081465}}$$

Solution gas oil ratio ($p < p_b$)

$$R_{sr} = a_1 p_r^{a_2} + (1 - a_1) p_r^{a_3}$$

$$R_{sr} = \frac{R_s}{R_{sb}}$$

$$p_r = \frac{p}{p_b}$$

$$a_1 = A_o \gamma_g^{A_1} \gamma_{API}^{A_2} T^{A_3} p_b^{A_4}$$

$$a_2 = B_o \gamma_g^{B_1} \gamma_{API}^{B_2} T^{B_3} p_b^{B_4}$$

$$a_3 = C_o \gamma_g^{C_1} \gamma_{API}^{C_2} T^{C_3} p_b^{C_4}$$

Note: All pressures in the above equations are measured in p_{sig} .

Reduced variable approach

The reduced solution gas oil ratio is defined as the solution gas oil ratio divided by the solution gas oil ratio at the bubble point. The reduced pressure is defined as the pressure divided by the bubble point pressure. Using the above relationship, the reduced solution gas oil ratio and the solution gas oil ratio at the bubble point are used to solve for the actual solution gas oil ratio at any pressure below the bubble point.

A Coefficients	B Coefficients	C Coefficients
$A_0 = 9.73 \times 10^{-7}$	$B_0 = 0.022339$	$C_0 = 0.725167$
$A_1 = 1.672608$	$B_1 = 1.004750$	$C_1 = 1.485480$
$A_2 = 0.929870$	$B_2 = 0.337711$	$C_2 = 0.164741$
$A_3 = 0.247235$	$B_3 = 0.132795$	$C_3 = 0.091330$
$A_4 = 1.056052$	$B_4 = 0.302065$	$C_4 = 0.047094$

Oil FVF – saturated

$$B_o = \frac{\rho_{st} + 0.01357 \cdot R_s \gamma_g}{\rho_{oR}}$$

$$\rho_{oR} = \rho_{bs} - \left(0.00302 + 1.505 \rho_{bs}^{-0.951}\right) (T - 60)^{0.938} + \left(0.0233 \left(10^{-0.0161 \cdot \rho_{bs}}\right)\right) (T - 60)^{0.475}$$

$$\rho_{bs} = \rho_{po} + \left(0.167 + 16.181 \left(10^{-0.0425 \cdot \rho_{po}}\right)\right) \left(\frac{\rho}{1000}\right) - 0.01 \left(0.299 + 263 \left(10^{-0.0603 \cdot \rho_{po}}\right)\right) \left(\frac{\rho}{1000}\right)^2$$

In the above equation, an initial estimate of ρ_{po} is calculated as follows:

$$\rho_{po} = 52.8 - 0.01 R_{sb}$$

After this initial value is known, ρ_{po} is calculated through a 10-step iteration process using the following equations. The values from the ninth and tenth iterations are averaged to yield a final value for ρ_{po} .

$$\rho_a = -49.893 + 85.0149 \cdot \gamma_g - 3.70373 \cdot \gamma_g \rho_{po} + 0.047981 \cdot \gamma_g \rho_{po}^2 + 2.98914 \cdot \rho_{po} - 0.035688 \cdot \rho_{po}^2$$

$$\rho_{po} = \frac{R_s \gamma_g + 4600 \cdot \gamma_o}{73.71 + \frac{R_s \gamma_g}{\rho_a}}$$

Oil FVF – undersaturated

$$B_o = B_{ob} e^{(c_o (p_b - p))}$$

The oil compressibility used in this equation is obtained from the Vasquez and Beggs correlation. All pressures in the above equations are measured in psia.

Correlation limits

Variable	Rs Correlation Limits	pbp Correlation Limits
T	70 - 307 °F	74 - 327 °F
p _b	106 - 5312 psia	70 - 6700 psia
B _{ob}	1.040 - 2.082 bbl/stb	N/A
R _s or R _{sb}	102 - 1808 scf/stb	10 - 1870 scf/stb
γ _g	0.561 - 1.101	0.556 - 1.367
γ _o	11.6 - 53.4 °API	12 - 55 °API

Oil correlation limits

Correlation	T (°F)	p (psia)	p _b (psia)	B _o (Rbbl/st-bbl)	R _s (scf/st-bbl)
Al-Marhoun (Middle East Oil)	75 - 240		107 - 4315	1.02 - 2.42	24 - 1901
De Ghetto et al. (Heavy and Extra-Heavy Oils)	131.4 - 250.7	1038.49 - 7411.54	208.86 - 4021.96	1.057 - 1.362	17.21 - 640.25
Glaso (North Sea Oil)	80 - 280	400 - 4000	150 - 7127	1.087 - 2.588	90 - 2637
Hanafy et al. (Egyptian Oil)	107 - 327		36 - 5003	1.032 - 4.35	7 - 4272
Khan et al. (Saudi Arabian Oil)	75 - 240	14.7 - 5015	107 - 4315		24 - 1901
Ng and Egbogah	70 - 295				

Correlation	T (°F)	p (psia)	p _b (psia)	B _o (Rbbl/st-bbl)	R _s (scf/st-bbl)
Petrosky and Farshad (Gulf of Mexico Oil)	114 - 288	1700 - 10692	1574 - 6523	1.1178 - 1.6229	217 - 1406
Standing (California Oil)	60 - 260 (p _{bp}) 100 - 260 (B _o)		200 - 6000	1.024 - 2.15	20 - 1425
Vasquez and Beggs (Generally Applicable)		140.7 - 9514.7			
Velarde et al. (Reduced Variable Approach)	See Velarde et al		See Velarde et al	See Velarde et al	See Velarde et al

Correlation	g _g	v _o (°API)	μ _o (cp)	μ _{os} (cp)	μ _{od} (cp)
Al-Marhoun (Middle East Oil)	0.752 - 1.367	14.3 - 44.6			
De Ghetto et al. (Heavy and Extra-Heavy Oils)	0.623 - 1.517	6 - 22.3	2.4 - 354.6	2.1 - 295.9	7.7 - 1386.9
Glaso (North Sea Oil)	0.65 - 1.276	22.3 - 48.1	0.119 - 106.6		
Hanafy et al. (Egyptian Oil)	0.752 - 1.367	17.8 - 47.7	0.13 - 71		
Khan et al. (Saudi Arabian Oil)		14.3 - 44.6		0.13 - 77.4	
Ng and Egbogah		5 - 58			
Petrosky and Farshad	0.5781 -	16.3 - 45			

Correlation	g_g	v_o (°API)	μ_o (cp)	μ_{os} (cp)	μ_{od} (cp)
(Gulf of Mexico Oil)	0.8519				
Standing (California Oil)	0.5 - 1.5	16.5 - 63.8			
Vasquez and Beggs (Generally Applicable)	0.511 - 1.351	15.3 - 59.5			
Velarde et al. (Reduced Variable Approach)	See <u>Velarde et al</u>	See <u>Velarde et al</u>			

Correlation	T_{sp} (°F)	p_{sp} (psia)
De Ghetto et al. (Heavy and Extra-Heavy Oils)	59 - 177.8	14.5 - 752.2

Correlation	ρ_o (g/cm ³)	ρ_{ob} (g/cm ³)
Hanafy et al. (Egyptian Oils)	0.648 - 1.071	0.428 - 0.939

Pressure loss calculations

In order to have flow in a pipe system, a pressure difference is needed, as fluids flow from a high pressure point to a low pressure point. You can identify three components that define this pressure difference:

1. Hydrostatic pressure loss
2. Frictional pressure loss
3. Kinetic pressure loss

For most applications, kinetic losses are minimal and can be ignored. Thus, the equation that describes the overall pressure losses can be expressed as the sum of two terms:

$$\Delta P_T = \Delta P_{HH} + \Delta P_f$$

Note: The phrases "pressure loss," "pressure drop," and "pressure difference" can be used interchangeably.

In upward (or “uphill” in the context of pipelines) flow, fluids must overcome the back-pressure exerted by the effective column of fluid acting against the direction of flow. Fluids must also overcome friction losses due to the interaction of the fluid with the pipe wall.

In downward (or “downhill” in the context of pipelines) flow, friction effects act against the direction of flow, but in this case, the effective hydrostatic column helps the fluid to overcome such friction losses.

Hydrostatic pressure losses are a function of the density of the fluid in the pipe. Frictional losses depend on the fluid properties and flowing conditions within the pipe.

There are a number of calculation methods used to account for hydrostatic and frictional fluid losses under a variety of flow conditions. The correlations that are included in Harmony™ are as follows:

Single-phase flow (internally used when single-phase flow is found):

- Fanning gas
- Fanning liquid

Multiphase flow:

- Beggs & Brill
- Gray
- Hagedorn & Brown
- Petalas and Aziz

Single-phase flow

Single-phase flow pressure calculations include the density, friction component, hydrostatic component, and flow correlations.

Density

Density (ρ) is used in hydrostatic pressure difference calculations. The method for calculating ρ depends on whether flow is compressible or incompressible (multiphase or single-phase). It follows that:

- For a single-phase liquid, calculating the density is easy, and ρ is simply the liquid density.

- For a single-phase gas, ρ varies with pressure (since gas is compressible), and the calculation must be done sequentially, in small steps, to allow the density to vary with pressure.

Friction component

During pipe flows, friction results from the resistance of the fluid to movement. Friction can be thought of as energy that is “lost” or “dissipated” (transformed into non-useful thermal energy) in the system. In single-phase flow scenarios, the frictional component can be found by the general Fanning equation:

$$\Delta P_f = \frac{2f\rho v^2 L}{144g_c D}$$

This correlation can either be used for single-phase gas or for single-phase liquid pipe flows.

Osborne Reynolds (1842–1912) experimentally investigated the relationship between the pressure drop and flow rate in a pipe. He found that at low rates, the pressure drop was directly proportional to the flow rate. He also observed that as he increased the flow rate, the measured data started to behave erratically. It was only when he used extremely high rates that he was able to reproduce his experimental data again.

After introducing a dye into the flow, Reynolds observed that at low rates of flow, the dye described a smooth flow path (linear) along the pipe. After increasing the flow rate, the dye presented perturbations, and if the rate was increased even further, the dye fluctuated erratically throughout the pipe. He named the smooth (stable) flow 'laminar flow regime', and the disturbed (unstable) flow 'turbulent flow regime'. Reynolds proposed to make use of the dimensionless ratio of inertia to viscous forces (now named after him) as an indication of the transition from flow regimes:

$$Re = \frac{\rho v^2}{\mu v / D}$$

In field units, the Reynolds number can be rewritten as:

$$Re = \frac{1488\rho v D}{\mu}$$

Considering the interaction of the fluid with the pipe wall, the friction factor results from the analysis (momentum flux) of the wall shear stress, and the kinetic energy per unit volume due to the movement of the fluid inside the pipe:

$$f = \frac{2\tau g_c}{\rho v^2}$$

In other words, the friction factor depends on the fluid properties and flowing conditions in the system.

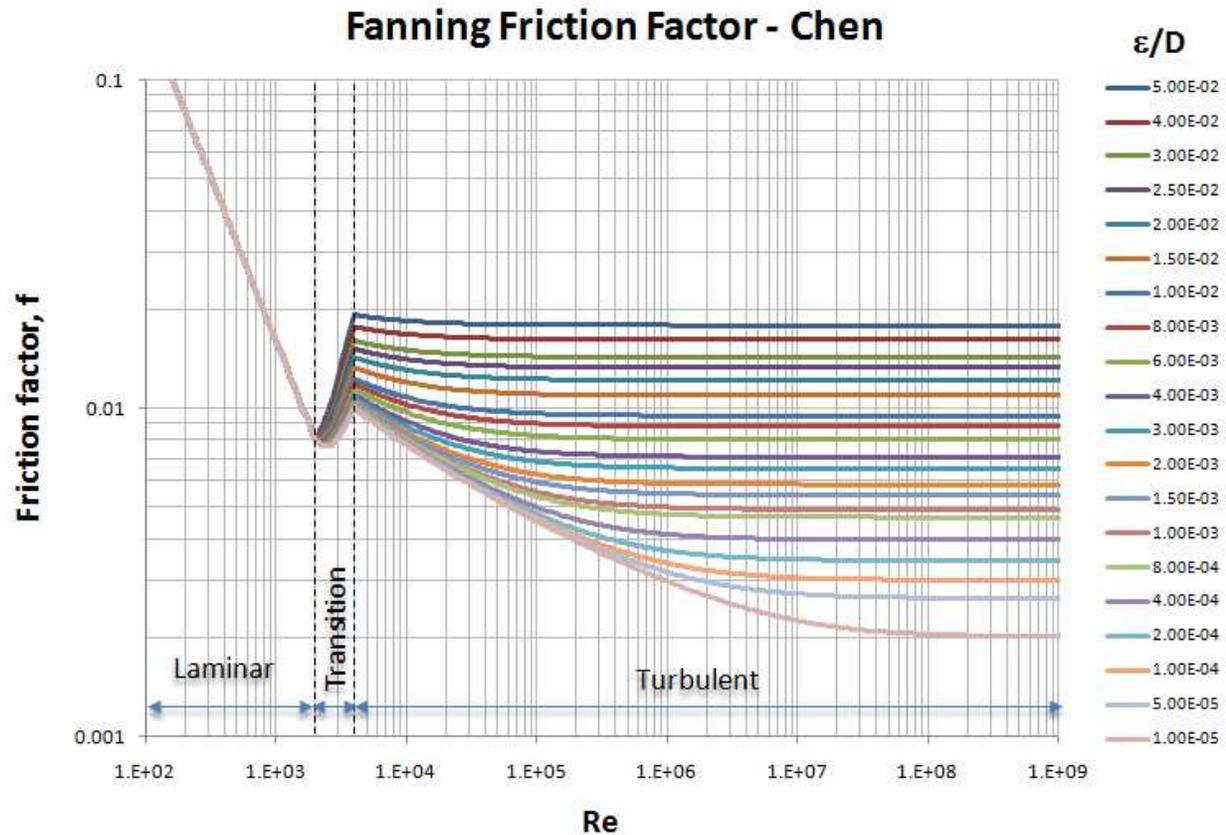
Blasius was the first to present a correlation between the Reynolds number and the friction factor for a very limited range of applications.

Nikuradse experimentally identified a relationship between the flow regimes (using the Reynolds number), the pipe roughness, and friction. Nikuradse found that pressure losses were higher for rougher pipes than for smooth ones due to frictional effects. He also observed that for small Reynolds numbers (in the laminar flow regime), the friction factor was the same for rough and smooth pipes. Several authors have since tried to relate the Reynolds number and the absolute roughness of the pipe to estimate the friction factor.

In Harmony, the Fanning friction factor for Reynolds numbers in the laminar flow regime ($Re \leq 2000$) is found by:

$$f = \frac{16}{Re}$$

In the turbulent flow regime ($Re \geq 4000$), the friction factor is obtained from the Chen (1979) equation.



$$\frac{1}{\sqrt{f}} = -4.0 \log_{10} \left[0.2698 \left(\frac{\epsilon}{D} \right) - \frac{5.0452}{Re} \log_{10} \left\{ 0.3539 \left(\frac{\epsilon}{D} \right)^{1.1098} + \frac{5.8506}{Re^{0.8981}} \right\} \right]$$

The friction factor in the transition from laminar to turbulent flow ($2000 < Re < 4000$) is approximated using the following expression:

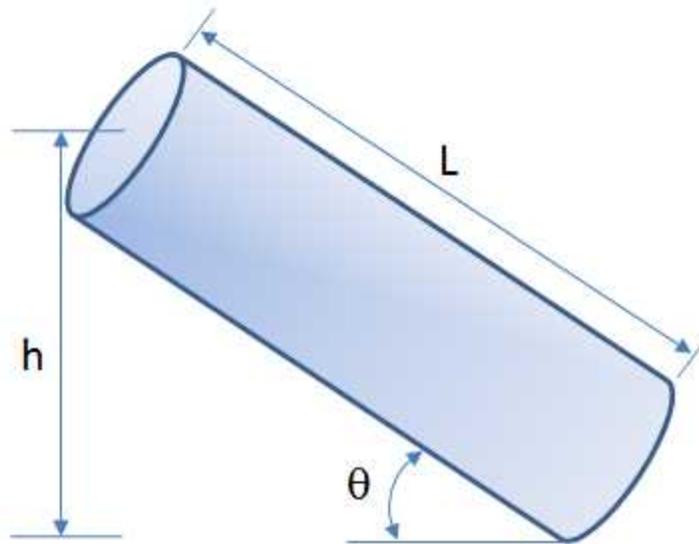
$$f = \frac{f_{Lam}(4000 - Re) + f_{Turb}(Re - 2000)}{2000}$$

Hydrostatic component

This component is of importance only when there are differences in elevation from the inlet end to the outlet end of a pipe segment. (In horizontal pipes this component is zero.) The hydrostatic pressure difference (ΔP_{HH}) can be applied to all correlations simply by adding it to the friction component. The hydrostatic pressure drop (ΔP_{HH}) is defined for a vertical pipe as follows:

$$\Delta P_{HH} = \frac{\rho g}{144g_c} \cdot h$$

A generalized form accounting for pipe inclination (using the angle with respect to the horizontal) can be written as:



$$\Delta P_{HH} = \frac{\rho g}{144g_c} L \cdot \sin(\theta)$$

Note: To use the angle with respect to the vertical (for example, in well deviation surveys), change the trigonometric function to cosine.

For liquids, the density (ρ) is constant, and the above equation is easily evaluated.

For gases, density varies with pressure. Therefore, to evaluate the hydrostatic pressure loss or gain, the pipe (or wellbore) is subdivided into a sufficient number of segments, such that the density in each segment can be assumed to be constant. Note that this is equivalent to a Multi-Step Cullender and Smith calculation.

Flow correlations

Many single-phase correlations exist that were derived for different operating conditions or from laboratory experiments. Generally speaking, these only account for the friction component (that is, they are applicable to horizontal flow). Typical examples are:

- Fanning gas (also known as Multi-Step Cullender and Smith when applied to wellbores)
- Fanning liquid

In Harmony™, for cases that involve a single phase, the Gray, Hagedorn and Brown, Beggs and Brill and Petalas and Aziz methods revert to the Fanning single-phase correlations. For example, if the Gray correlation was selected, but there was only gas in the system, the Fanning gas correlation is used.

Note: Single-phase correlations can be used for vertical or inclined flow provided that the hydrostatic pressure drop is accounted for in addition to the friction component. Even though a particular correlation may have been developed for flow in a horizontal pipe, incorporation of the hydrostatic pressure drop allows the correlation to be used for flow in a vertical pipe. This adaptation is rigorous, and has been implemented into all of the correlations used in Harmony™. Nevertheless, for identification purposes, the correlation's name has been left unchanged.

Multiphase flow

Multiphase pressure loss calculations parallel single-phase pressure loss calculations. Essentially, each multiphase correlation makes its own specific modifications to the hydrostatic pressure difference and the friction pressure loss calculations, in order to make them applicable to multiphase situations.

The presence of multiple phases greatly complicates pressure drop calculations. This is due to the fact that the properties of each fluid present must be taken into account. Also, the interactions between each phase must be considered. Mixture properties must be used, and therefore the gas and liquid in-situ volume fractions throughout the pipe need to be determined. In general, multiphase correlations are essentially two-phase, and not three-phase. Accordingly, the oil and water phases are combined, and treated as a pseudo single-liquid phase, while gas is considered a separate phase.

The hydrostatic pressure difference calculation is modified by defining a mixture density. This is determined by a calculation of in-situ liquid holdup (amount of liquid in the pipe section). Some correlations determine holdup based on defined flow patterns.

The friction pressure loss is modified in several ways by adjusting the friction factor (f), the density (ρ), and velocity (v) to account for multiphase mixture properties.

The multiphase pressure loss correlations in Harmony™ are based on the Fanning friction pressure loss equation. They can be grouped as follows:

Do not account for flow patterns:

- **Gray** — Developed using data from gas and condensate wells.
- **Hagedorn and Brown** — Derived using a test well running different oils and air

Consider flow patterns:

- **Beggs and Brill** — Correlation derived from experimental data for vertical, horizontal, inclined uphill, and downhill flow of gas-water mixtures
- **Petalas and Aziz** — Mechanistic model combined with empirical correlations. This multi-purpose correlation is applicable for all pipe geometries, inclinations, and fluid properties.

These models can be used for gas-liquid multiphase flow, single-phase gas, or single-phase liquid, because in single-phase mode, they revert back to the Fanning equation, which is equally applicable to either gas or liquid.

Note: The Gray and Hagedorn and Brown correlations were derived for vertical wells and may not apply to horizontal pipes.

Flow fluid properties

Superficial Velocities

The superficial velocity of each phase is defined as the volumetric flow rate of the phase divided by the cross-sectional area of the pipe (as though that phase alone was flowing through the pipe). Therefore:

$$v_{sL} = \frac{Q_L}{\frac{\pi}{4} \cdot D^2}$$

$$v_{sG} = \frac{Q_G \cdot B_G}{\frac{\pi}{4} \cdot D^2}$$

Since the liquid phase accounts for both oil and water:

$$Q_L = Q_O B_O + (Q_W - Q_{WC} Q_G) B_W$$

and the gas phase accounts for the solution gas going in and out of the oil as a function of pressure:

$$Q_G = Q_G - Q_O R_S$$

the superficial velocities can be rewritten as:

$$v_{sL} = \frac{Q_o \cdot B_o + (Q_w - Q_{wc} Q_G) B_w}{\frac{\pi}{4} \cdot D^2}$$

$$v_{sG} = \frac{(Q_G - Q_o R_s) B_g}{\frac{\pi}{4} \cdot D^2}$$

The oil, water, and gas formation volume factors (B_o , B_w , and B_g) are used to convert the flow rates from standard (or stock tank) conditions to the prevailing pressure and temperature conditions in the pipe.

Since the actual cross-sectional area occupied by each phase is less than the cross-sectional area of the entire pipe, the superficial velocity is always less than the true in-situ velocity of each phase.

Mixture velocity

Mixture velocity is another parameter that is often used in multiphase flow correlations. The mixture velocity is given by:

$$V_m = v_{sL} + v_{sG}$$

Slippage and the liquid holdup effect

When two or more phases are present in a pipe, they tend to flow at different in-situ velocities. These in-situ velocities depend on the density and viscosity of each phase. Typically the phase that is less dense flows faster than the other. This causes a "slip" effect between the phases. As a consequence, the in-situ volume fractions of each phase (under flowing conditions) differ from the input volume fractions of the pipe.



If the slip condition is omitted, the in-situ volume fraction of each phase is equal to the input volume fraction.

In-situ volume fraction (liquid holdup with slip)

The in-situ volume fraction, E_L (or H_L), is often the value that is estimated by multiphase correlations. Because of slippage between phases, the liquid holdup (E_L) can be significantly

different from the input liquid fraction (C_L). In other words, the liquid slip holdup (E_L) is the fraction of the pipe that is filled with liquid when the phases are flowing at different velocities. It can be defined as follows:

$$E_L = \frac{V_L}{V_p} = \frac{A_L}{A_p}$$

Input volume fraction (no-slip holdup)

The input volume fractions are defined as:

$$C_L = \frac{Q_L}{Q_L + Q_G B_g}$$

$$C_G = \frac{Q_G B_g}{Q_L + Q_G B_g}$$

We can also write them as a function of the superficial velocities as:

$$C_L = \frac{v_{sL}}{v_m}$$

$$C_G = \frac{v_{sG}}{v_m}$$

Note: Q_L is the liquid rate at the prevailing pressure and temperature. Similarly, $Q_G B_g$ is the gas rate at the prevailing pressure and temperature.

The input volume fractions, C_L and E_L , are known quantities, and are often used as correlating variables in empirical multiphase correlations. In the event that slip effects are neglected (gas and liquid traveling at the same velocity), the in-situ liquid fraction is equal to the input liquid fraction ($E_L = C_L$).

Actual velocities

Once the liquid holdup has been determined, the actual velocities for each phase can be determined as follows:

$$v_L = \frac{v_{sL}}{E_L}$$

$$v_G = \frac{v_{sG}}{1 - E_L}$$

Density

Density (ρ) is used in hydrostatic pressure difference calculations. The method for calculating ρ depends on whether flow is compressible or incompressible (multiphase or single-phase). For multiphase flow, the calculations become even more complicated than for single-phase flow because ρ is calculated from the in-situ mixture density, which in turn is calculated from the "liquid holdup." The liquid holdup, or in-situ liquid volume fraction, is obtained from one of the multiphase flow correlations, and depends on several parameters including the gas and liquid rates and the pipe diameter. Note that this is in contrast to the way density is calculated for friction pressure loss.

Mixture density

Mixture density is a measure of the in-situ density of the mixture, and is defined as follows:

$$\rho_m = \rho_L E_L + \rho_G E_G = \rho_L E_L + \rho_G (1 - E_L)$$

Note: Mixture density is defined in terms of in-situ volume fractions (E_L), whereas no-slip density is defined in terms of the input volume fractions (C_L).

No-slip density

"No-slip" density is the density that is calculated with the assumption that both phases are moving at the same in-situ velocity. No-slip density is therefore defined as follows:

$$\rho_{NS} = \rho_L C_L + \rho_G C_G = \rho_L C_L + \rho_G (1 - C_L)$$

Note: No-slip density is defined in terms of the input volume fractions (C_L), whereas the mixture density is defined in terms of the in-situ volume fractions (E_L).

Mixture viscosity

Mixture viscosity is a measure of the in-situ viscosity of the mixture and can be defined in several different ways. In general, unless otherwise specified, is defined as follows:

$$\mu_m = \mu_L E_L + \mu_G E_G = \mu_L E_L + \mu_G (1 - E_L)$$

Note: Mixture viscosity is defined in terms of in-situ volume fractions (E_L), whereas no-slip viscosity is defined in terms of input volume fractions (C_L).

No-slip viscosity

"No-slip" viscosity is the viscosity that is calculated with the assumption that both phases are moving at the same in-situ velocity. There are several definitions of "no-slip" viscosity. In general, unless otherwise specified, μ_{NS} is defined as follows:

$$\mu_{NS} = \mu_L C_L + \mu_G C_G = \mu_L C_L + \mu_G (1 - C_L)$$

Surface tension

The surface tension (interfacial tension) between the gas and liquid phases has very little effect on two-phase pressure drop calculations. However, a value is required for calculating certain dimensionless numbers used in some of the pressure drop correlations. Empirical relationships for estimating the gas / oil interfacial tension and the gas / water interfacial tension were presented by Baker and Swerdloff, Hough and by Beggs.

Gas / oil interfacial tension

The dead oil interfacial tension at temperatures of 68°F and 100°F is given by:

$$\sigma_{68} = 39 - 0.2571 (\text{API})$$

$$\sigma_{100} = 37.5 - 0.2571 (\text{API})$$

If the temperature is greater than 100°F, the value at 100°F is used. If the temperature is less than 68°F, the value at 68°F is used. For intermediate temperatures, linear interpolation is used.

As pressure is increased and gas goes into solution, the gas / oil interfacial tension is reduced. The dead oil interfacial tension is corrected for this by multiplying by a correction factor:

$$C = 1.0 - 0.024P^{0.45}$$

The interfacial tension becomes zero at miscibility pressure, and for most systems this is at any pressure greater than about 5000 psia. After the correction factor becomes zero (at about 3977 psia), 1 dyne/cm is used for calculations.

Gas / water interfacial tension

The gas / water interfacial tension at temperatures of 74°F and 280°F is given by:

$$\sigma_{W(74)} = 75 - 1.108P^{0.349}$$

$$\sigma_{W(280)} = 53 - 0.1048P^{0.637}$$

If the temperature is greater than 280°F, the value at 280°F is used. If the temperature is less than 74°F, the value at 74°F is used. For intermediate temperatures, linear interpolation is used.

Friction component

In pipe flow, friction pressure loss is the component of total pressure loss caused by viscous shear effects. Friction pressure loss **always acts against the direction of flow**. It is combined with the hydrostatic pressure difference (which may be positive or negative, depending on whether the flow is upward (also known as uphill) or downward (downhill)) to give the total pressure loss.

Friction pressure loss is calculated from the Fanning friction factor equation as follows:

$$\Delta P_f = \frac{2f\rho v^2 L}{144g_c D}$$

In the above equation, the variables f , ρ , and v are treated differently by each correlation.

Each multiphase flow correlation finds the friction factor differently. This calculation depends, in part, on the gas and liquid flow rates, but also on the standard Fanning (single-phase) friction factor chart. When evaluating the Fanning friction factor, there are many ways of calculating the Reynolds number depending on how the density, viscosity, and velocity of the two-phase mixture are defined. For example, the Beggs and Brill calculation of the Reynolds number uses mixture properties that are calculated by prorating the property of each individual phase in the ratio of the *input* volume fraction (and not of the *in-situ* volume fraction).

Hydrostatic component

Hydrostatic pressure difference is the component of pressure loss (or gain) attributed to the earth's gravitational effect. It is of importance only when there are differences in elevation from the inlet end to the outlet end of a pipe segment. This pressure difference can be positive or negative depending on the reference point (inlet higher vertically than outlet, or outlet higher than inlet). **Under ALL circumstances**, regardless of what sign convention is used, the contribution of the hydrostatic pressure calculation must be such that it tends to make the pressure at the vertically-lower end higher than that at the upper end.

The hydrostatic pressure difference is calculated as follows:

$$\Delta P_{HH} = \frac{\rho g}{144g_c} L \cdot \sin(\theta)$$

In the equation above, the problem lies in finding an appropriate value for density, as discussed below:

- For a single-phase liquid, the density of the mixture is equal to the liquid density.
- For a single-phase gas, density varies with pressure, and the calculation must be done sequentially in small steps to allow density to vary with pressure.
- For multiphase flow, density is calculated from the in-situ mixture density, which in turn is calculated from the liquid holdup. The liquid holdup is obtained from multiphase flow correlations, such as Beggs and Brill, and depends on the gas and liquid rates, pipe diameter, etc.
- For a horizontal pipe segment, $\theta = 0.0$, and there is NO hydrostatic pressure loss.

Flow correlations

Many of the published multiphase flow correlations are applicable for vertical flow only, while others apply for horizontal flow only. Other than the Beggs and Brill correlation and the Petalas and Aziz mechanistic model, there are not many correlations that were developed for the whole spectrum of flow situations that can be encountered in oil and gas operations — namely, uphill, downhill, horizontal, inclined, and vertical flow. However, we have adapted all of the correlations (as appropriate) so that they apply to all flow situations. This includes these multiphase flow correlations:

- **Beggs and Brill** — one of the few published correlations capable of handling all of the flow directions. It was developed using sections of pipeline that could be inclined at any angle.
- **Gray** — developed for vertical flow in wet gas wells. We have modified it, so that it applies to flow in all directions by calculating the hydrostatic pressure difference using only the vertical elevation of the pipeline segment, and the friction pressure loss based on the total length of the pipeline.
- **Hagedorn and Brown** — developed for vertical flow in oil wells. We have modified it, so that it applies to flow in all directions by calculating the hydrostatic pressure difference using only the vertical elevation of the pipe segment, and the friction pressure loss based on the total pipeline length.
- **Petalas and Aziz** — developed to overcome the limitations imposed by using previous correlations. It applies to all pipe geometries, fluid properties, and flow in all directions. A mechanistic approach is combined with empirical closure relationships to provide a model that is more robust than

other models and can be used to predict pressure drop and holdup in pipes over a more extensive range of conditions.

Each of these correlations was developed for its own unique set of experimental conditions, or designed using a mechanistic modeling approach, and accordingly, results vary between them.

For multiphase flow in essentially vertical wells, the available correlations are Beggs and Brill, Petalas and Aziz, Gray and Hagedorn and Brown. If used for single-phase flow, these four correlations devolve to the Fanning gas or Fanning liquid correlation as needed.

When creating a new wellbore, Harmony sets a default multiphase correlation depending upon the type of well that exists in the Entity Viewer. This default correlation is based on our expected use cases, and thus may not apply to every wellbore. Of course, the correlation for the wellbore configuration can be changed at any time.

Note: The Gray and Hagedorn and Brown correlations were derived for vertical wells and may not apply to horizontal pipes. In Harmony, the Gray, the Hagedorn and Brown, the Beggs and Brill, and the Petalas and Aziz models revert to the appropriate single-phase Fanning correlation (Fanning liquid or Fanning gas).

Beggs and Brill correlation

The Beggs and Brill (1973) correlation is one of the few published correlations capable of handling all these flow directions. It was developed measuring the flow of water and air through 1" and 1-1/2" sections of acrylic pipe that could be inclined at different angles from the horizontal.

The Beggs and Brill multiphase correlation deals with both friction pressure loss and hydrostatic pressure difference. First, the corresponding flow pattern for the particular combination of gas and liquid rates (segregated, intermittent, or distributed) is determined. The liquid holdup, and hence, the in-situ density of the gas-liquid mixture, is then calculated according to the identified flow pattern to obtain the hydrostatic pressure difference. A two-phase friction factor is calculated based on the input gas-liquid ratio and the Fanning friction factor. From this, friction pressure loss is calculated using input gas-liquid mixture properties.

In our implementation, whenever single-phase flow is encountered during pressure loss calculations, the Beggs and Brill correlation devolves to the Fanning gas or Fanning liquid correlation.

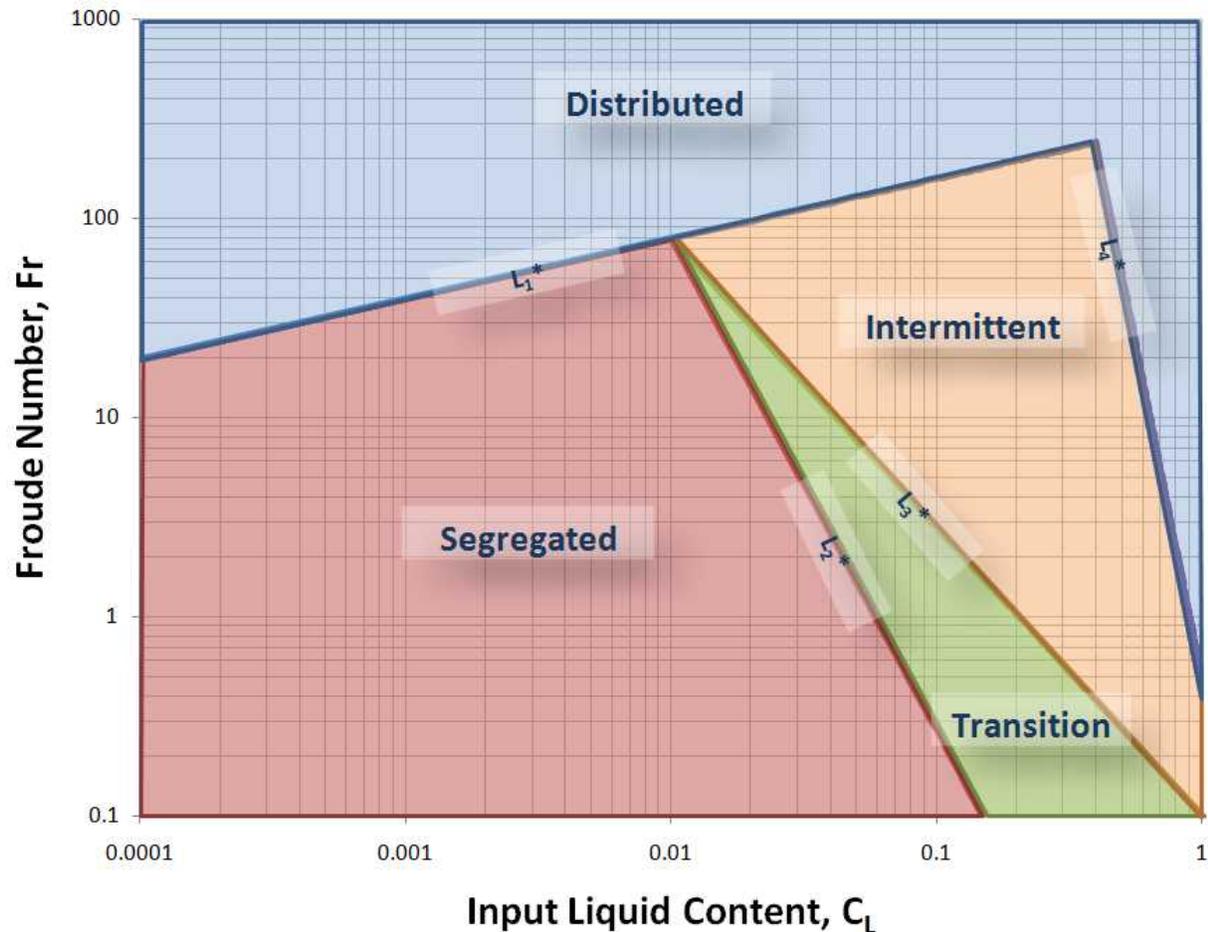
Flow pattern map

Unlike the Gray or Hagedorn and Brown correlations, the Beggs and Brill correlation needs to identify the flow pattern at the given flowing conditions in order to calculate the liquid holdup

and friction. For this purpose, the Beggs and Brill correlation makes use of a horizontal flow-pattern map built based on the Froude number of the mixture (Fr_m) and input liquid content (no-slip liquid holdup, C_L).

In order to build the flow map, the observed flow patterns were grouped as: segregated (stratified, wavy, and annular flow), intermittent (plug and slug flow), distributed (bubble and mist flow), and transition (flow pattern included after a modification of the original publication that considers the region between the segregated and intermittent grouped patterns).

The boundaries between these groups of flow patterns appear as curves in a log-log plot in the original publication by Beggs and Brill. This was later revised so that straight lines could be used instead. We use this modified flow-pattern map in our calculations. The revised lines that define the boundaries are defined as follows (where * stands for the modification of the original curve to a straight line in a log-log plot):



$$L_1^* = 316C_L^{0.302}$$

$$L_2^* = 0.0009252 C_L^{-2.4684}$$

$$L_3^* = 0.1 C_L^{-1.4516}$$

$$L_4^* = 0.5 C_L^{-6.738}$$

The identified flow pattern is the one that would exist if the pipe were horizontal. Unless the pipe is actually in the horizontal position, the Beggs and Brill correlation is not able to recognize the actual flow pattern under the given conditions. Therefore, to calculate the liquid holdup, we first determine the liquid holdup for the horizontal flow, and this value is then corrected for the angle of interest.

The Froude number is a dimensionless number that relates the inertia with respect to the gravitational forces. For a mixture, it can be obtained by:

$$Fr_m = \frac{v_m^2}{gD}$$

Once the input liquid content (C_L) and Froude number of the mixture (Fr_m) are determined, the corresponding flow pattern is identified when the following inequalities are satisfied.

Segregated

$$\text{if } C_L < 0.01 \text{ and } Fr_m < L_1^*$$

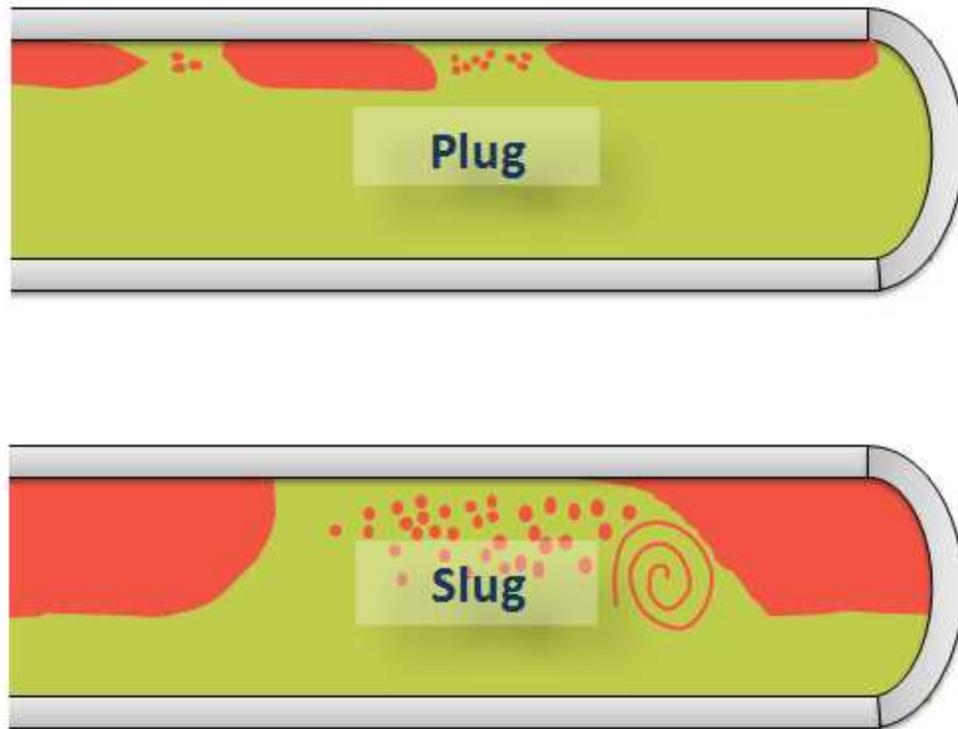
$$\text{or } C_L \geq 0.01 \text{ and } Fr_m < L_2^*$$



Intermittent

if $0.01 \leq C_L < 0.4$ and $L_3^* < Fr_m \leq L_1^*$

or $C_L \geq 0.4$ and $L_3^* < Fr_m \leq L_4^*$



Distributed

if $C_L < 0.4$ and $Fr_m \geq L_1^*$

or $C_L \geq 0.4$ and $Fr_m > L_4^*$



Transition

$$\text{if } C_L \geq 0.01 \text{ and } L_2^* < Fr_m < L_3^*$$

Hydrostatic Pressure Difference

Once the flow pattern has been determined, the liquid holdup is then calculated. Beggs and Brill divided the liquid holdup calculation into two parts. First, the liquid holdup for horizontal flow, $E_L(0)$, is determined. Afterward, this horizontal holdup is corrected for inclined flow to obtain the actual holdup, $E_L(\theta)$. The horizontal holdup must be $E_L(0) \geq C_L$. Therefore, in the event that $E_L(0) < C_L$, the horizontal holdup is set to $E_L(0) = C_L$. The expression used to calculate the horizontal holdup changes per flow pattern group as follows:

Segregated

$$E_L(0) = \frac{0.98 C_L^{0.4846}}{Fr_m^{0.0868}}$$

Intermittent

$$E_L(0) = \frac{0.845 C_L^{0.5351}}{Fr_m^{0.0173}}$$

Distributed

$$E_L(0) = \frac{1.065 C_L^{0.5824}}{Fr_m^{0.0609}}$$

Transition

$$E_{L(0)transition} = A E_{L(0)segregated} + B E_{L(0)intermittent}$$

where:

$$A = \frac{L_3^* - Fr_m}{L_3^* - L_2^*}$$

$$B = 1 - A$$

Once the horizontal in-situ liquid volume fraction is determined, the actual liquid volume fraction is obtained by correcting $E_L(0)$ by an inclination factor $B(\theta)$:

$$E_L(\theta) = B(\theta) \cdot E_L(0)$$

where:

$$B(\theta) = 1 + \beta \left[\sin(1.8\theta) - \frac{1}{3} \sin^3(1.8\theta) \right]$$

β is a function of the flow pattern and is also related to the direction of inclination of the pipe (uphill or downhill flow).

For **uphill** flow

Segregated

$$\beta = \left(1 - C_L \right) \ln \left[\frac{0.011 N_w^{3.539}}{C_L^{3.768} Fr_m^{1.614}} \right]$$

Intermittent

$$\beta = \left(1 - C_L\right) \ln \left[\frac{2.96 C_L^{0.305} Fr_m^{0.0978}}{N_w^{0.4473}} \right]$$

Distributed

$$\beta = 0$$

For downhill flow

ALL flow pattern groups

$$\beta = \left(1 - C_L\right) \ln \left[\frac{2.96 C_L^{0.305} Fr_m^{0.0978}}{N_w^{0.4473}} \right]$$

where Fr_m is the Froude number of the mixture and N_{Lv} is the liquid velocity number given by:

$$N_{Lv} = 1.938 v_{sL} \sqrt[4]{\frac{P_L}{\sigma}}$$

Note: β must always be ≥ 0 . Therefore, if a negative value is calculated for β , $\beta = 0$.

Once the actual liquid holdup $E_L(\theta)$ is calculated, the mixture density ρ_m is obtained. Mixture density, in turn, is used to calculate the pressure change due to the hydrostatic head of the vertical component of the pipe or well.

$$\Delta P_{HH} = \frac{\rho_m g}{144g_c} L \cdot \sin(\theta)$$

Beggs and Brill - Friction Pressure Loss

In order to calculate frictional losses, a normalizing friction factor (f_{NS}) is used. To determine f_{NS} , we use the Fanning friction factor calculated using the Chen equation. For this purpose, the no-slip Reynolds number is used:

$$Re_{NS} = \frac{\rho_{NS} v_m D}{\mu_{NS}}$$

Based on experimental data, Beggs and Brill presented a correlation for the ratio of the two-phase friction factor (f_{tp}) and the normalizing (no-slip) friction factor resulting in the following exponential equation:

$$\frac{f_{tp}}{f_{NS}} = e^S$$

The value of S depends on the no-slip and the actual liquid holdup:

$$S = \frac{\ln y}{-0.0523 + 3.182(\ln y) - 0.8725(\ln y)^2 + 0.01853(\ln y)^4}$$

where:

$$y = \frac{C_L}{(E_L)^2}$$

Severe instabilities have been observed when the equation for S is used as published. To solve for them, the following considerations are used:

- If $y = 0$, then $S=0$ (to ensure that the expression is reduced to single-phase liquid)
- If $1 < y < 1.2$, then $S = \ln(2.2y - 1.2)$

After a valid value for S has been found, you can solve for the two-phase friction factor:

$$f_{tp} = f_{NS}e^S$$

Finally, the expression for pressure loss due to friction is:

$$\Delta P_f = \frac{2f_{tp} v_m^2 \rho_{NS} L}{144g_c D}$$

Gray Correlation

The Gray correlation was developed by H.E. Gray (1978) specifically for wet gas wells. Although this correlation was developed for vertical flow, we have implemented it to be used in both vertical and inclined pipe pressure-drop calculations. To correct pressure drop for situations with a horizontal component, the hydrostatic head has only been applied to the vertical component of the pipe, while friction is applied to the entire length of pipe.

First, the in-situ liquid volume fraction is calculated. The in-situ liquid volume fraction is then used to calculate mixture density, which in turn is used to calculate the hydrostatic pressure

difference. The input gas-liquid mixture properties are used to calculate an effective roughness of the pipe. This effective roughness is then used in conjunction with a constant Reynolds number of 10^7 to calculate the Fanning friction factor. The pressure difference due to friction is calculated using the Fanning friction pressure-loss equation.

Gray – Hydrostatic Pressure Difference

The Gray correlation uses three dimensionless numbers in combination to predict the in-situ liquid volume fraction. These three dimensionless numbers are:

$$N_1 = \frac{\rho_{NS}^2 v_m^4}{g \sigma_L^* (\rho_L - \rho_G)}$$

$$N_2 = \frac{g D^2 (\rho_L - \rho_G)}{\sigma_L^*}$$

$$N_3 = 0.0814 \left[1 - 0.0554 \ln \left(1 + \frac{730 R_v}{R_v + 1} \right) \right]$$

where:

$$R_v = \frac{v_{sL}}{v_{sG}}$$

$$\sigma_L^* = \alpha \frac{q_o \sigma_o + 0.617 q_w \sigma_w}{q_o + 0.617 q_w}$$

$$\alpha = \frac{0.00220462 \left[\frac{lbm}{s^2} \right]}{1 \left[\frac{dyne}{cm} \right]}$$

The dimensionless numbers are then combined as follows:

$$E_L = 1 - (1 - C_L) \cdot (1 - e^{f_1})$$

where:

$$f_1 = -2.314 \left[N_1 \left(1 + \frac{205}{N_2} \right) \right]^{N_3}$$

Once the liquid holdup (E_L) is calculated, it is used to obtain the mixture density (ρ_m). Mixture density, in turn, is used to compute the pressure change due to the hydrostatic head of the vertical component of the pipe.

$$\Delta P_{HH} = \frac{\rho_m g}{144g_c} L \cdot \sin(\theta)$$

Gray – Friction Pressure Loss

The Gray Correlation assumes that the effective (also known as apparent) roughness of the pipe (k_e) is dependent on the value of R_v . The conditions are as follows:

If $R_v \geq 0.007$ then:

$$k_e = k^o$$

if $R_v < 0.007$ then:

$$k_e = k + R_v \left[\frac{k^o - k}{0.007} \right]$$

where:

$$k^o = \frac{28.5 \sigma_L^*}{\rho_{NS} V_m^2}$$

$$R_v = \frac{v_{sL}}{v_{sG}}$$

and k is the absolute roughness of the pipe (single-phase dry gas flow). The resulting effective roughness (k_e) must be larger than or equal to 2.77×10^{-5} .

The relative roughness of the pipe is then calculated by dividing the effective roughness by the diameter of the pipe. The Fanning friction factor is obtained using the Chen equation and assumes a Reynolds number of 107. Finally, the expression for the friction pressure loss is:

$$\Delta P_f = \frac{2f_{tp} v_m^2 \rho_{NS} L}{144g_c D}$$

Note: The original publication contains a misprint in the calculation of k_e : the constant should be 0.007 instead of 0.0007. We include this correction in our calculations. Additionally, the volume of water condensation is estimated using Bukacek's correlation (including the corrections by McKetta and Wehe) and is considered in the pressure-drop calculations.

Hagedorn and Brown

Experimental data obtained from a 1500 ft deep instrumented vertical test well was used in the development of the Hagedorn and Brown correlation. Pressures were measured for flow in tubing sizes of 1", 1 ¼" and 1 ½" OD. A wide range of liquid rates and gas / liquid ratios were used. As with the Gray correlation, our software calculates pressure drops for horizontal and inclined flow using the Hagedorn and Brown correlation, although the correlation was developed strictly for vertical wells. The software uses only the vertical depth to calculate pressure loss due to hydrostatic head, and the entire pipe length to calculate friction.

The Hagedorn and Brown method has been modified for the bubble flow regime (Economides et al, 1994). If bubble flow exists, the Griffith correlation is used to calculate the in-situ volume fraction. In such cases, the Griffith correlation is also used to calculate pressure drop due to friction. If bubble flow does not exist, then the original Hagedorn and Brown correlation is used to calculate the in-situ liquid volume fraction. Once the in-situ volume fraction is determined, it is compared with the input volume fraction. If the in-situ volume fraction is smaller than the input volume fraction, the in-situ fraction is set to equal the input fraction ($E_L = C_L$). Next, the mixture density is calculated using the in-situ volume fraction and used to calculate the hydrostatic pressure difference. The pressure difference due to friction is calculated using a combination of in-situ and input gas-liquid mixture properties.

Hagedorn and Brown - Hydrostatic Pressure Difference

The Hagedorn and Brown correlation uses four dimensionless parameters (based on the work of Duns and Ros) to correlate liquid holdup. These four parameters are:

$$N_{Lv} = 1.938 v_{sL} \sqrt[4]{\frac{\rho_L}{\sigma}}$$

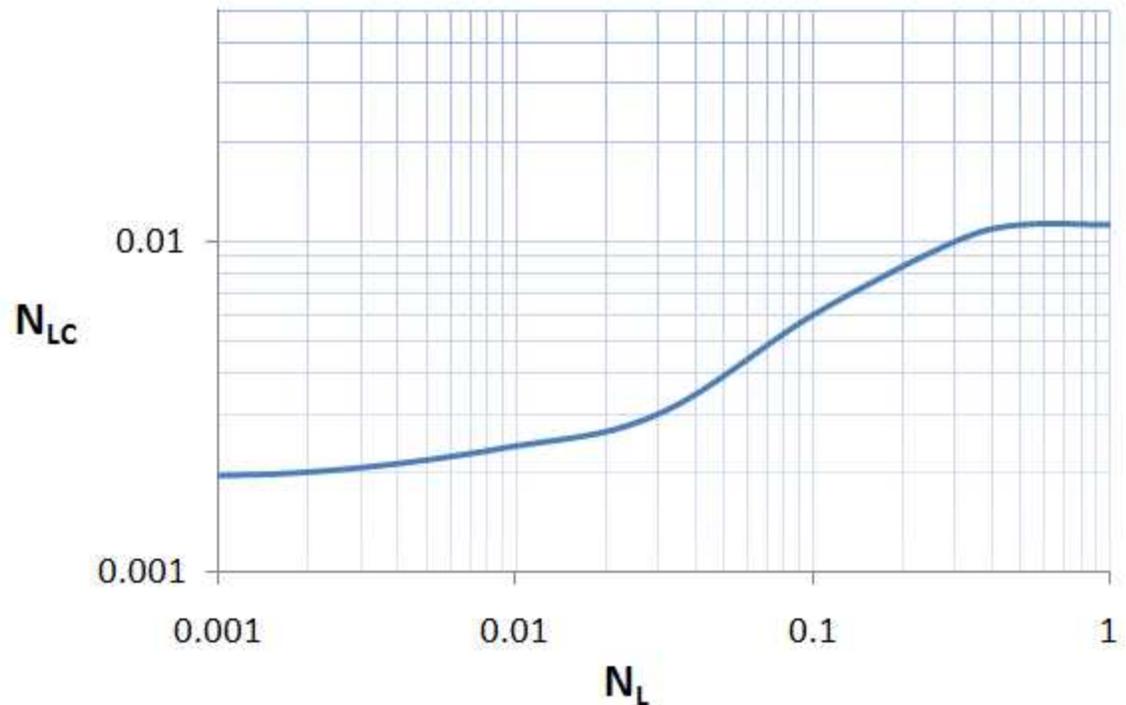
$$N_{Gv} = 1.938 v_{sG} \sqrt[4]{\frac{\rho_L}{\sigma}}$$

$$N_d = 120.872 D \sqrt{\frac{\rho_L}{\sigma}}$$

$$N_d = 0.15726 \mu_L \sqrt[4]{\frac{1}{\rho_L \sigma^3}}$$

The method of calculation is based on the use of several plots where various combinations of these parameters are calculated and plotted against some correlated terms to determine the liquid holdup. For programming purposes, these curves were discretized into equations.

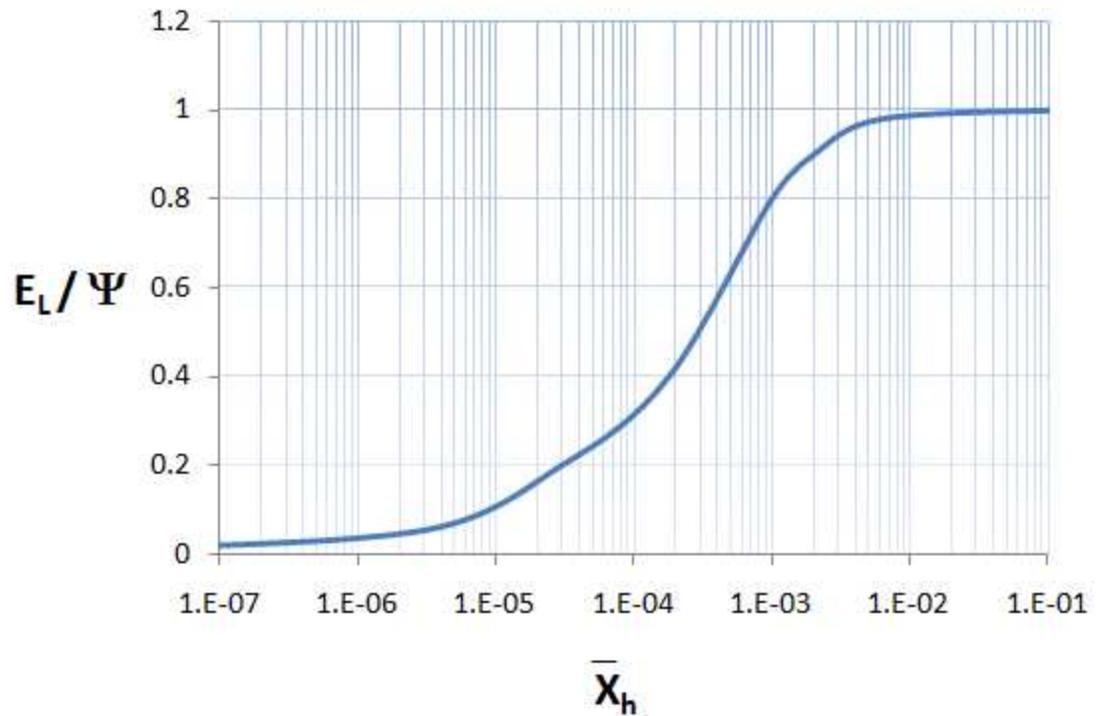
The first curve provides a value for a dimensionless parameter called N_{LC} , which is correlated with the dimensionless number N_L . Therefore, once N_L is calculated, it is possible to obtain N_{LC} from the following plot:



The value of N_{LC} is then used to calculate the dimensionless number, \bar{X}_h :

$$\bar{X}_h = \left(\frac{N_{Lv}}{N_{Gv}^{0.575}} \right) \left(\frac{\rho}{\rho_{sc}} \right)^{0.10} \left(\frac{N_{LC}}{N_d} \right)$$

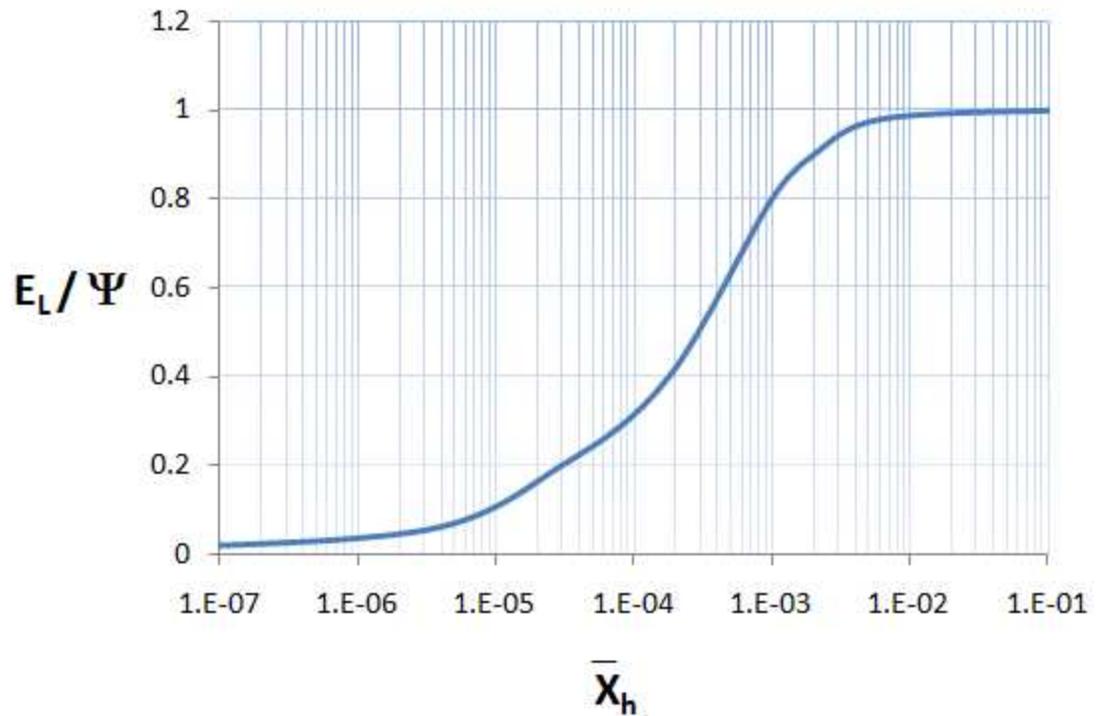
The next plot contains a curve correlating the liquid holdup divided by a correction factor (E_L / Ψ) against the dimensionless group, \bar{X}_h . After \bar{X}_h is calculated, you can then find the value of E_L / Ψ by making use of the following plot:



Finally, the third curve correlates the correction factor Ψ with the dimensionless number, \bar{X}_Ψ :

$$\bar{X}_\Psi = \frac{N_{Gv} N_L^{0.38}}{N_d^{2.14}}$$

A typical discretized curve to find Ψ can be as follows:



After finding Ψ , the in-situ liquid volume fraction (E_L) can be calculated taking the previously found E_L / Ψ :

$$E_L = \left(\frac{E_L}{\Psi} \right) \cdot \Psi$$

We have implemented a correction to replace the liquid holdup value with the "no-slip" (input) liquid volume fraction, if the calculated liquid holdup is less than the no-slip liquid volume fraction:

$$\text{if } E_L < C_L, \text{ then } E_L = C_L$$

After finding E_L , the hydrostatic head is calculated by the standard equation:

$$\Delta P_{HH} = \frac{\rho_m g}{144g_c} L \cdot \sin(\theta)$$

where:

$$\rho_m = \rho_L E_L + \rho_G (1 - E_L)$$

Hagedorn and Brown - Friction Pressure Loss

The friction factor is calculated using the Chen equation using a Reynolds number equal to:

$$Re = \frac{\rho_{NS} V_m D}{\mu_m}$$

Note: In the Hagedorn and Brown correlation, mixture viscosity is given by:

$$\mu_m = \mu_L^{E_L} \mu_G^{(1-E_L)}$$

The pressure loss due to friction is then given by:

$$\Delta P_f = \frac{2f \rho_f v_m^2 L}{144g_c D}$$

where:

$$\rho_f = \frac{\rho_{NS}^2}{\rho_m}$$

Modification to the Hagedorn and Brown Correlation: the Griffith Correlation for Bubble Flow

The Hagedorn and Brown correlation makes use of the Griffith correlation (1961) for the bubble flow regime. Bubble flow exists if $C_G < L_B$, where:

$$L_B = 1.071 - 0.2218 \left(\frac{v_m^2}{D} \right)$$

If the calculated value of L_B is less than 0.13, then L_B is set to 0.13. If the flow regime is found to be bubble flow, then the Griffith correlation is applied. Otherwise, the original Hagedorn and Brown correlation is used.

In the Griffith correlation, liquid holdup is given by:

$$E_L = 1 - \frac{1}{2} \left[1 + \frac{v_m}{v_s} - \sqrt{\left(1 + \frac{v_m}{v_s} \right)^2 - 4 \left(\frac{v_{sg}}{v_s} \right)} \right]$$

Griffith suggested a constant value of $v_s = 0.8$ ft/s as a good average value, which is the one considered in our calculations.

The true in-situ liquid velocity is given by:

$$v_L = \frac{v_{sL}}{E_L}$$

The hydrostatic head is then calculated the standard way.

The pressure drop due to friction is also affected by the use of the Griffith correlation because E_L enters into the calculation of the Reynolds number via the in-situ liquid velocity. The Reynolds number is calculated using the following format:

$$Re_L = \frac{\rho_L v_L D}{\mu_L}$$

The single-phase liquid density, in-situ liquid velocity, and liquid viscosity are used to calculate the Reynolds number. This is unlike the majority of multiphase correlations, which usually define the Reynolds number in terms of mixture properties rather than single-phase liquid properties. The Reynolds number is used to calculate the friction factor using the Chen equation. The liquid density and the in-situ liquid velocity are then used to calculate the pressure drop due to friction:

$$\Delta P_f = \frac{2f \rho_f v_L^2 L}{144g_c D}$$

Petalas and Aziz Mechanistic Model

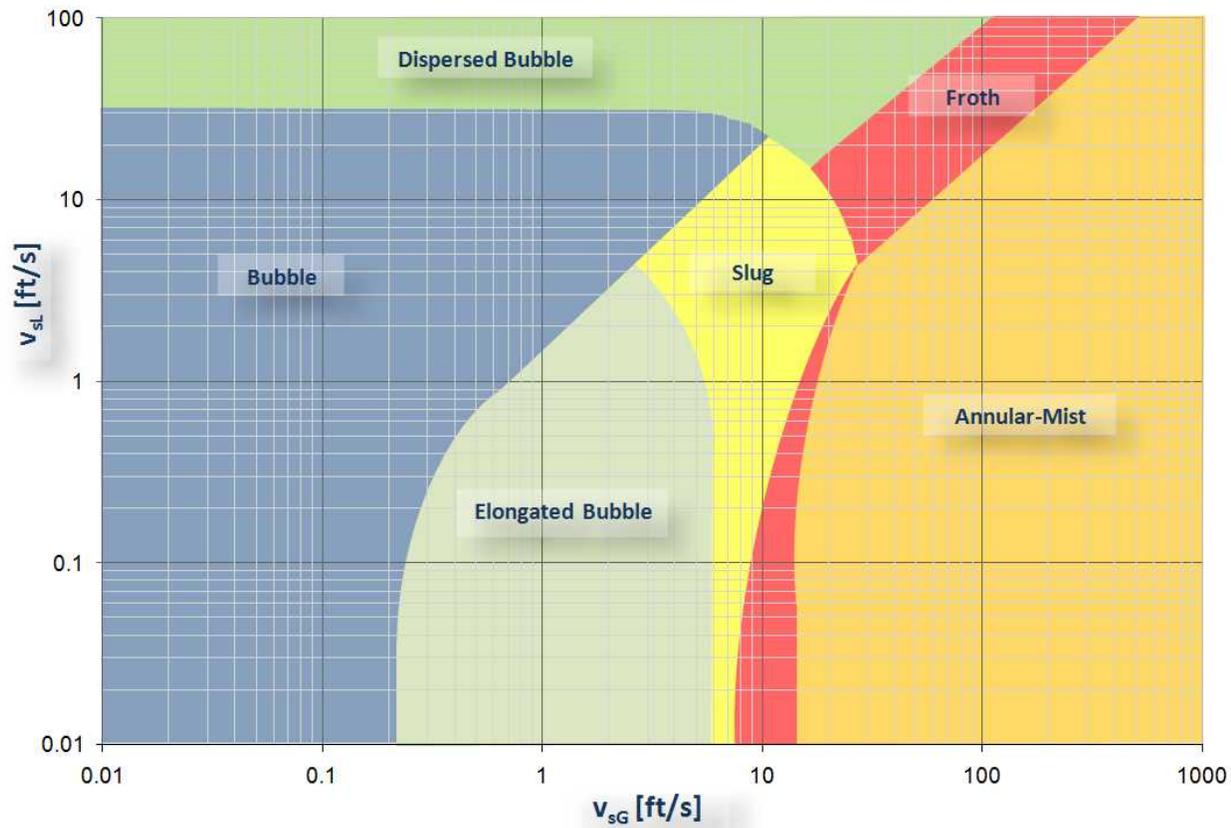
The Petalas and Aziz mechanistic model (2000) was not built for a specific set of data or fluid properties. Instead, the authors applied first principles to the possible flow patterns that can be observed at different inclinations. For this reason, it is applicable to any pipe inclination and fluid properties. The model is a refinement of a previous study by the authors (1996) where subsets of a database of over 20,000 laboratory measurements and data from approximately 1,800 wells were used.

The method could be summarized as follows:

- Assume the existence of a flow pattern
- Evaluate if this flow pattern is stable:
 - If the check fails, go back and select another flow pattern
 - If stable conditions are met, go ahead with the calculation of liquid holdup and the friction factor

- Calculate pressure losses using the found values for the friction factor and liquid holdup

With the continuous evaluation of the stability of the flow patterns, you can create the corresponding flow-pattern map to the given flowing conditions. This screenshot shows a typical flow-pattern map for vertical upward gas-oil flow:



Flow Pattern Map

Dispersed Bubble flow

In order to have dispersed bubble flow, two requirements must be fulfilled.

The first criterion is based on Barnea's transition from dispersed to slug flow while using the slug liquid holdup calculation based on Gregory et al:

$$\frac{1}{1 + \left(\frac{v_m}{8.66}\right)^{1.39}} < 0.48$$

where:

$$v_m = v_{sG} + v_{sL}$$

Also, to be able to sustain dispersed bubble flow, the ratio of the superficial gas velocity with respect to the mixture velocity should be:

$$\frac{v_{sG}}{v_m} > 0.52$$

Stratified Flow

The consideration here is that stratified flow can be possible only in downward (downhill) or horizontal flow. A momentum balance is obtained based on the one proposed by Taitel and Dukler.

The first step consists in calculating \tilde{h}_L (dimensionless liquid height) by solving:

$$-A_L \left(\frac{dp}{dL} \right) - \tau_{wL} S_L + \tau_i S_i - p_L A_L \left(\frac{g}{g_c} \right) \sin(\theta) = 0$$

$$-A_G \left(\frac{dp}{dL} \right) - \tau_{wG} S_G - \tau_i S_i - p_G A_G \left(\frac{g}{g_c} \right) \sin(\theta) = 0$$

where:

$$\tau_{wG} = \frac{f_G \rho_G v_G^2}{2g_c}$$

$$\tau_{wL} = \frac{f_L \rho_L v_L^2}{2g_c}$$

$$\tau_{wi} = \frac{f_i \rho_G v_i |v_i|}{2g_c}$$

and

f_G is obtained from standard methods where:

$$Re_G = \frac{\rho_G v_G D_G}{\mu_G}$$

where the hydraulic diameter of the gas phase, D_G , is obtained by:

$$D_G = \frac{4 A_G}{S_G + S_i}$$

f_L from:

$$f_L = 0.452 f_{sL}^{0.731}$$

where f_{sL} is a friction factor based on the superficial velocity, which is calculated from standard methods using the pipe roughness and the Reynolds number:

$$Re_{sL} = \frac{\rho_L v_{sL} D}{\mu_L}$$

f_i from:

$$f_i = \left(0.004 + 0.5 \cdot 10^{-6} Re_{sL} \right) Fr_L^{1.335} \left(\frac{\rho_L D_G}{\rho_G v_G^2} \right)$$

using a liquid Froude number defined as:

$$Fr_L = \frac{v_L}{\sqrt{gh_L}}$$

use Lockhart-Martinelli parameters:

$$X^2 F_2 - F_1 - 4Y = 0$$

where:

$$X^2 = \frac{\left(\frac{\delta P}{\delta L} \right)_{sL}}{\left(\frac{\delta P}{\delta L} \right)_{sG}} = \frac{f_{sL} v_{sL}^2 \rho_L}{f_{sG} v_{sg}^2 \rho_G}$$

$$Y = \frac{(\rho_L - \rho_G) g \sin(\theta)}{\left(\frac{\delta P}{\delta L}\right)_{sG}} = \frac{(\rho_L - \rho_G) g \sin(\theta)}{2f_{sG} v_{sG}^2 \rho_G}$$

$$F_1 = \left(\frac{f_G}{f_{sG}}\right) \tilde{v}_G^2 \left[\frac{\tilde{S}_G}{\tilde{A}_G} + \frac{f_i}{f_G} \frac{|\tilde{v}_i|}{\tilde{v}_G} \left(\frac{\tilde{S}_i}{\tilde{A}_G} + \frac{\tilde{S}_i}{\tilde{A}_L} \right) \right]$$

$$F_2 = \frac{f_L}{f_{sL}} \tilde{v}_L^2 \frac{\tilde{S}_L}{\tilde{A}_L}$$

where:

$$\tilde{v}_i = \tilde{v}_G - \tilde{v}_L$$

with the geometric variables:

$$\tilde{h}_L = \frac{h_L}{D}$$

$$\tilde{S}_L = \frac{S_L}{D}$$

$$\tilde{A}_L = \frac{A_L}{D^2}$$

$$\tilde{A}_G = \frac{A_G}{D^2}$$

$$\tilde{v}_L = \frac{v_L}{v_{sL}}$$

$$\tilde{v}_G = \frac{v_G}{v_{sG}}$$

$$\tilde{v}_L = \frac{\tilde{A}}{\tilde{A}_L}$$

Solve for h_L / D iteratively. Afterwards, we verify that stratified flow exists if:

$$v_G = \left(1 - \frac{h_L}{D}\right) \sqrt{\frac{(\rho_L - \rho_G) g A_G \cos(\theta)}{\rho_G \frac{dA_L}{dh_L}}}$$

and if:

$$v_L > \sqrt{\frac{g D (1 - \tilde{h}_L) \cos(\theta)}{f_L}}$$

Note: When $\cos\theta \leq 0.02$, then, $\cos\theta = 0.02$.

To distinguish between stratified smooth and stratified wavy flow regimes:

stratified smooth flow exists if:

$$v_G \leq \sqrt{\frac{4 \mu_L (\rho_L - \rho_G) g \cos(\theta)}{s \rho_L \rho_G v_L}}$$

where $s=0.06$, and if:

$$Fr = \frac{v_L}{\sqrt{g h_L}} > 1.4$$

Annular-Mist Flow

Calculate the dimensionless liquid film thickness ($\tilde{\delta}_L$), making the momentum balance on the liquid film and gas core with liquid droplets:

$$-A_f \left(\frac{dp}{dL} \right) - \tau_{wL} S_L + \tau_i S_i - p_L A_L \left(\frac{g}{g_c} \right) \sin(\theta) = 0$$

$$-A_c \left(\frac{dp}{dL} \right) - \tau_i S_i - p_c A_c \left(\frac{g}{g_c} \right) \sin(\theta) = 0$$

Annular-mist flow exists if:

$$\tilde{\delta}_L < \tilde{\delta}_{L, \min}$$

where $\tilde{\delta}_{L, \min}$ is determined from the following equations:

$$2 f_f \frac{\rho_L}{(\rho_L - \rho_c)} \frac{v_{sL}^2}{g D \sin(\theta)} = \frac{E_f^3 \left(1 - \frac{3}{2} E_f \right)}{2 - \frac{3}{2} E_f}$$

$$E_f = \frac{A_f}{A} = 4 \tilde{\delta}_L (1 - \tilde{\delta}_L)$$

Solve for $\tilde{\delta}_{L, \min}$ iteratively.

Bubble Flow

Bubble flow exists if:

$$D > 19 \left[\frac{(\rho_L - \rho_G)}{g \rho_L^2} \right]^{\frac{1}{2}}$$

and if:

$$\cos(\theta) \leq \frac{3}{4\sqrt{2}} v_b^2 \left(\frac{C_1 Y^2}{g d_b} \right)$$

where:

$$C_1 = 0.8$$

$$\gamma = 1.3$$

$$d_b = 7\text{mm}$$

with:

$$v_b = 1.41 \left[\frac{g(\rho_L - \rho_G) \sigma}{\rho_L^2} \right]^{\frac{1}{4}} \sin(\theta)$$

Also, transition to bubble flow from intermittent flow occurs when:

$$E_L > 0.25$$

where:

$$E_L = \frac{E_{LS} v_t + v_{Gdb}(1 - E_{LS}) - v_{sG}}{v_t}$$

Intermittent Flow

Note: The intermittent flow model used here includes slug and elongated bubble flow regimes.

Intermittent flow exists if:

$$E_L > 0.24$$

where:

$$E_L = \frac{E_{LS} v_t + v_{Gdb}(1 - E_{LS}) - v_{sG}}{v_t}$$

If $E_L > 1$, then $E_L = C_L$.

and if:

$$E_L = \frac{1}{1 + \left(\frac{v_m}{8.66}\right)^{1.39}}$$

where:

$$V_m = V_{sL} + V_{sG}$$

- If $E_L > 0.24$ and $ELs < 0.9$, then slug flow
- If $E_L > 0.24$ and $ELs > 0.9$, then elongated bubble flow

Froth Flow

If none of the transition criteria for intermittent flow are met, the flow pattern is then designated as froth. Froth flow implies a transitional state between the other flow regimes.

Pressure loss calculations in multilayer wells

This topic describes the underlying logic for multilayer wellbore pressure calculations. For step-by-step instructions on how to set up multilayer wells, see [analyze well data](#). For information on what a multilayered well is, see [multilayered wells](#).

For wells with multiple layers, pressure calculations can only be performed in the [Production editor](#) under the following scenarios:

- Flow path = casing; Pressure source = casing or gauge
- Flow path = tubing; Pressure source = casing, tubing, or gauge
- Flow path = annulus; Pressure source = casing or tubing
- Flow path = gas lift (tubing or annular); Pressure source = tubing or casing

The underlying logic for pressure-drop calculations is essentially the same for both multilayer and single-layer wells. However, multilayer wellbore calculations are somewhat more complicated than single layer since different layers (formations) can produce at different rates.

Note: There is no limit to the number of layers in a multilayer well. For simplicity, the figures below generally show no more than three layers, but the logic holds for any number of layers.

In most cases, the production from each layer is similar (for example, each is producing some proportion of gas, oil, and water). For these common situations, the logic is relatively straightforward, with the wellbore containing the same overall fluid composition from top-to-bottom,

with the rate dropping as each layer is passed, and the production from that layer is removed. However, it is possible for each layer to produce a unique type of fluid – for example, one layer flowing only gas, a second layer flowing only water. When this situation occurs, then the logic can become more complicated. The rest of this help topic describes this logic in depth.

Note: Only fluid properties specified at the well level are used in wellbore pressure calculations. If properties are entered on a per-layer basis, they are not used in the wellbore pressure calculations, but instead are used in analyses created against that layer.

Fluid combinations

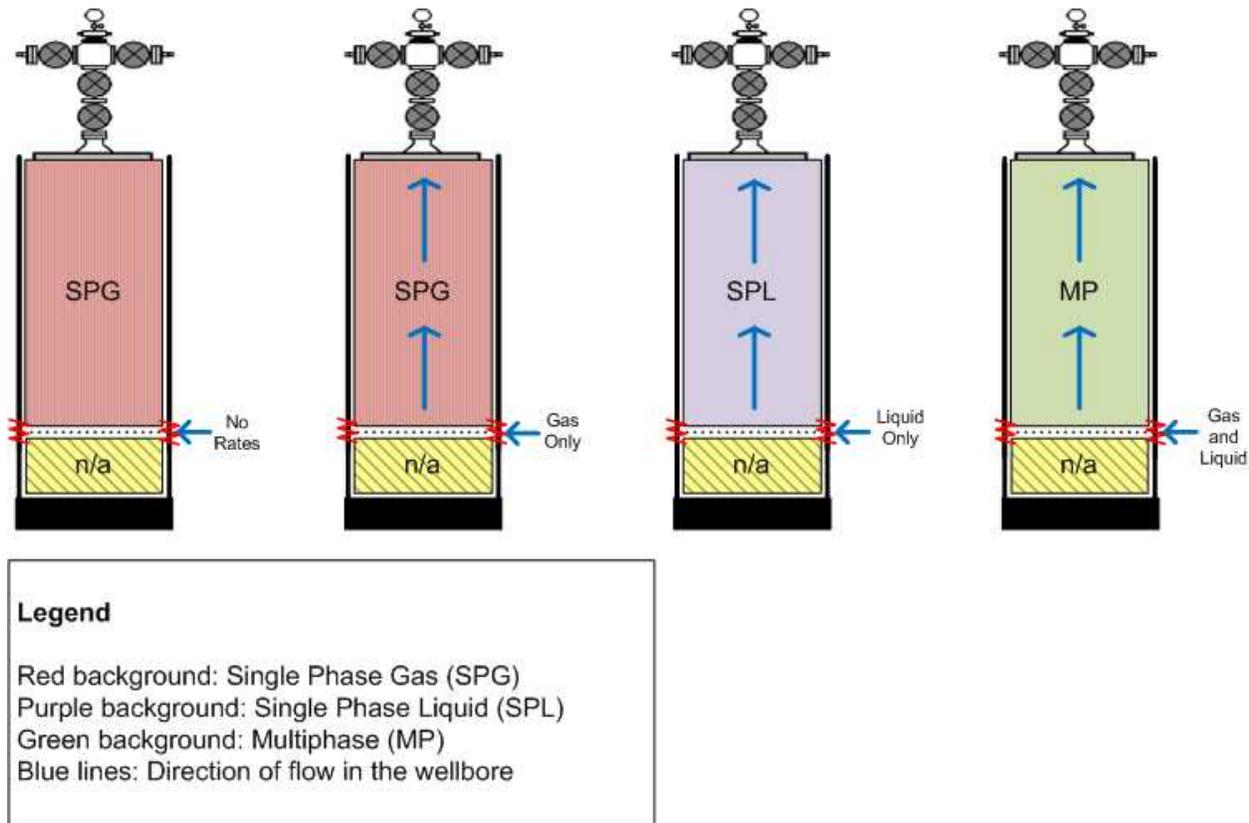
When mixing fluids, three possible rates are considered: gas, oil, and water. In addition, any or all of those rates can be zero, creating eight possible fluid combinations per layer. Thankfully, not all of those combinations require a unique method to calculate pressures. In fact, only three calculation methods are necessary:

1. Single-phase gas
2. Single-phase liquid
3. Multiphase (gas and liquid combined)

Note: These methods are described in [pressure loss calculations](#).

Examples: calculations when no tubing is present (casing flow only)

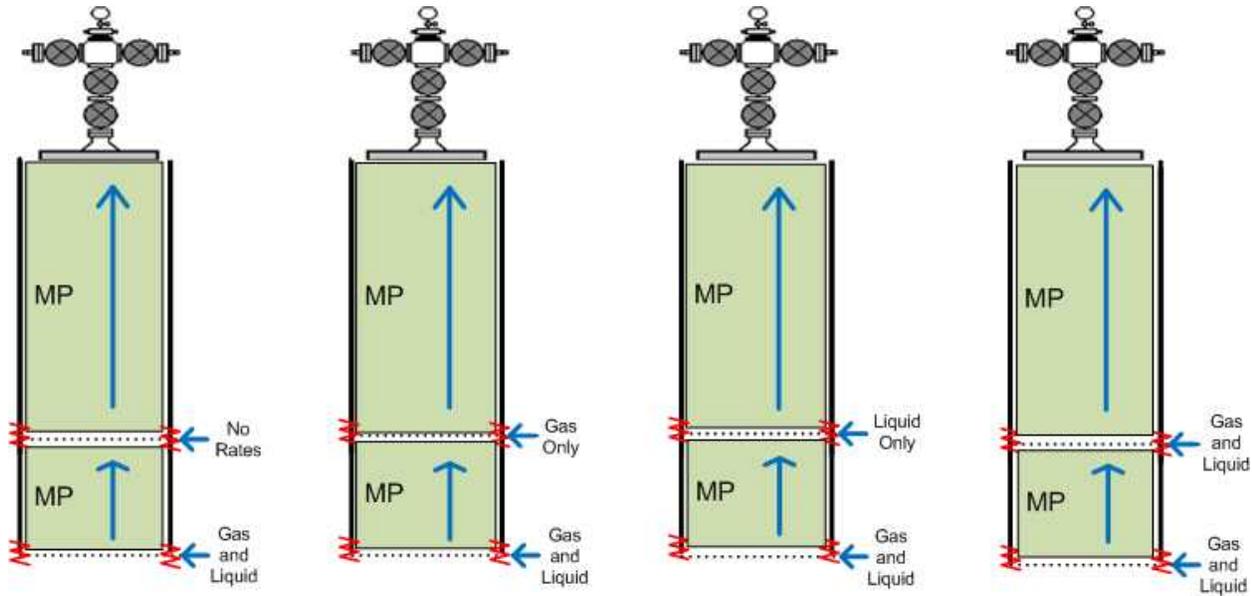
Pressure calculations within the casing string always assume that the direction of flow is towards the wellhead. The type of calculation performed (for example, single phase or multiphase) depends upon the constituent fluids within the wellbore. The following figure, with four different scenarios, shows the type of calculation required for each combination of inputs into the wellbore.



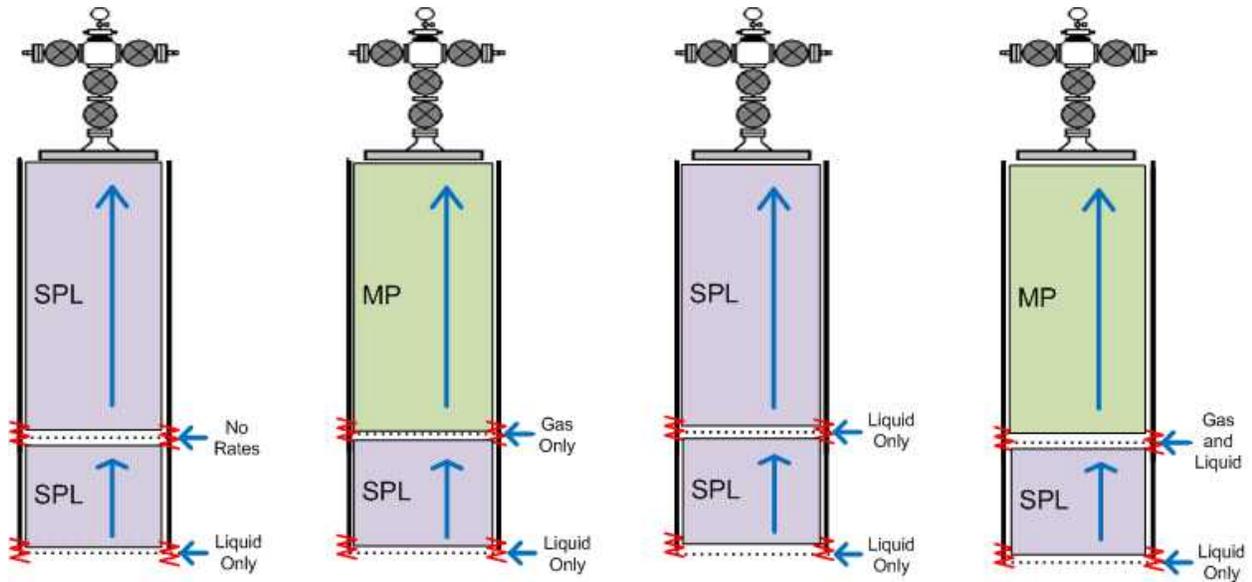
While the figure above only accounts for a single layer, it is useful as a reference case when further layers are considered. When additional layers are encountered, then the rates are summed to determine whether a single-phase gas, single-phase liquid, or multiphase calculation is required. However, a key difference exists when the deepest layer is shut in (no rates) – in such a case, the software examines all the layers above the deepest layer to determine whether there will be a column of static gas, or static liquid. The rules governing this are described in [Group D](#).

The following figures describe the logic that is used when there are two layers below end of tubing (EOT). This logic can be extrapolated for application to any number of layers.

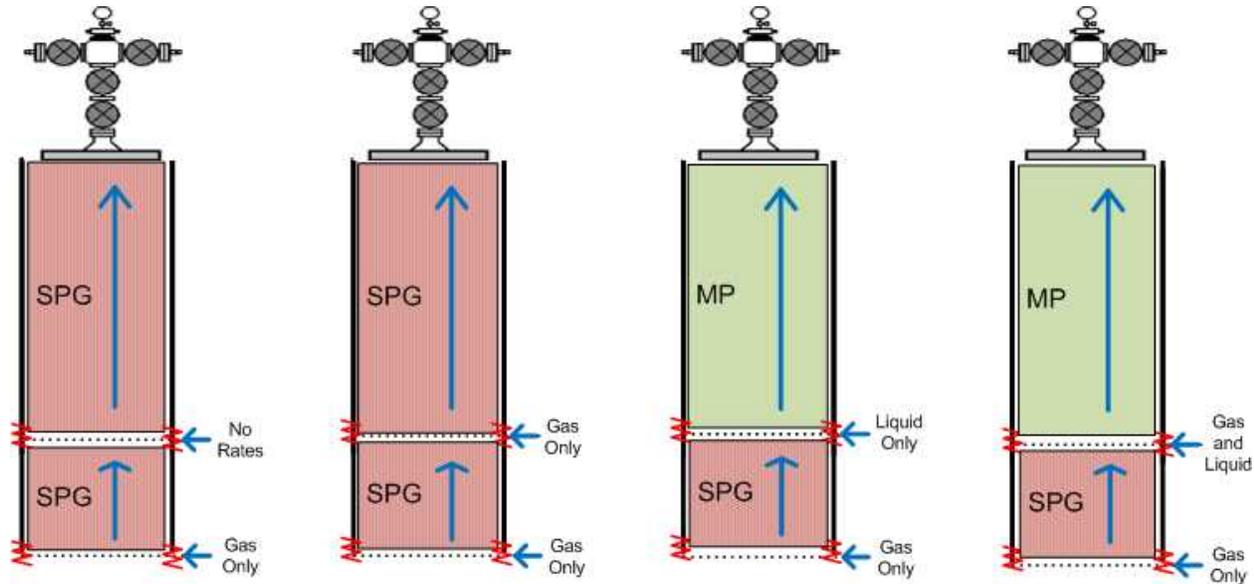
Group A: deepest layer flowing gas & liquid



Group B: deepest layer flowing liquid

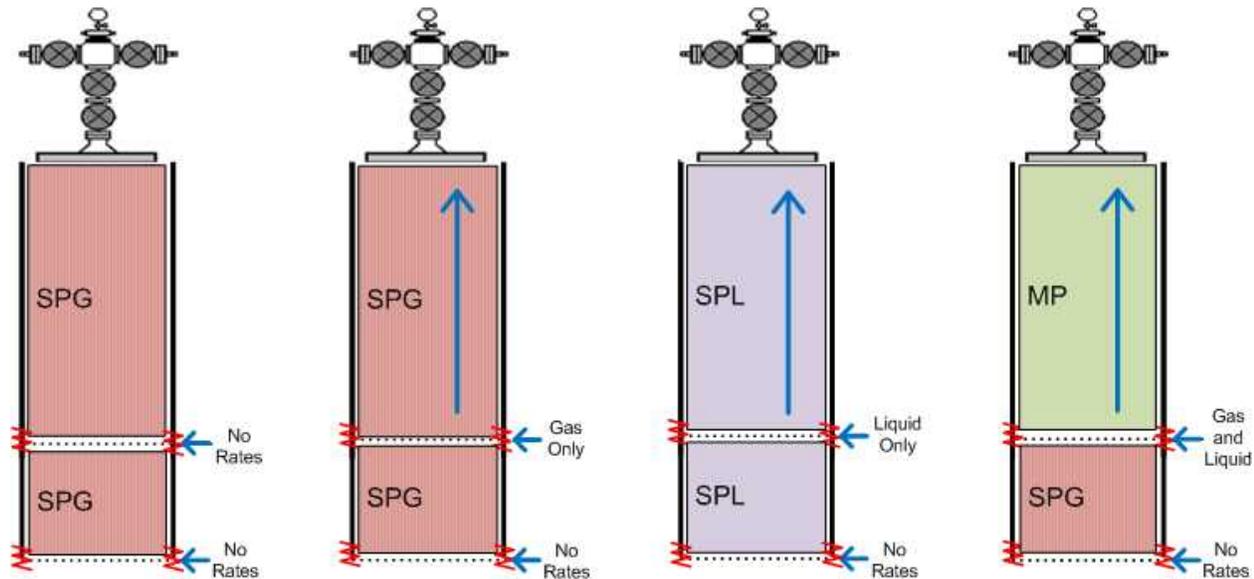


Group C: deepest layer flowing gas



Group D: deepest layer not flowing (shut-in)

When the deepest layer is shut in (zero rates), then a static column exists from the bottom of that layer up to the next flowing layer. This static column must be gas or liquid. The logic applied is as follows:



One key assumption is that if gas and liquid are produced from a single layer, then the gas carries that liquid upwards. If liquid loading is suspected, it can be analyzed using other methods (for example, Turner's equation).

Note: When calculating pressure at the overall well datum (Well MPP), a shut-in layer is presumed for calculation purposes.

Examples: calculations when tubing is the flow path

When tubing exists, and it is the flow path, we assume that the produced fluids travel up the tubing as soon as they are able to. Therefore, it follows that EOT forms an imaginary dividing line for the wellbore, so the overall calculations can be divided into two sections:

1. Calculations for all layers above EOT
2. Calculations for all layers below EOT

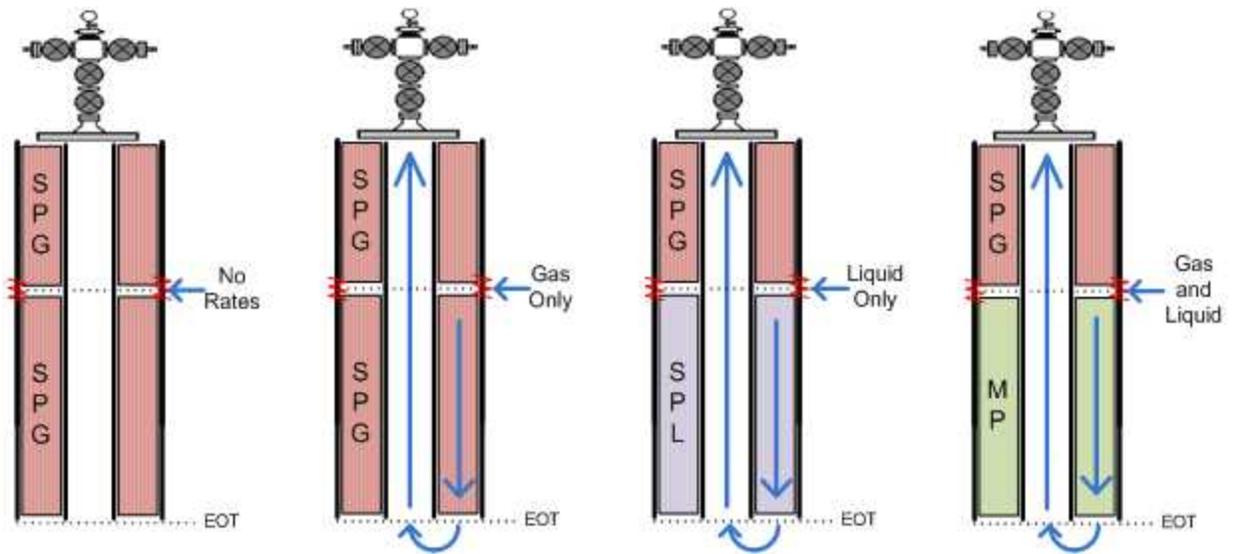
The examples below are categorized according to these two sections.

Examples: calculations for all layers above EOT

Calculations from the wellhead to EOT must always be performed, even if there are no layers above EOT. However, the order of events that takes place depends greatly on the pressure source chosen.

1. If the pressure source is "tubing", then the pressure at EOT is calculated first. This is done via the tubing path, using the total rates measured at surface. Once EOT pressure is known, then the pressure for each layer above EOT is calculated one at a time, following the annulus flow path.
2. If the pressure source is "casing", then the calculations follow the annulus flow path exclusively. From the surface down to the first layer, a static gas column is assumed to exist in the annulus. From the first layer down, the specified rates are used to calculate the pressure at the subsequent layer. On the other hand, if there is no layer between surface and EOT, then a static gas column is assumed throughout.

The following figure shows the possible fluid arrangements when a single layer exists above EOT:

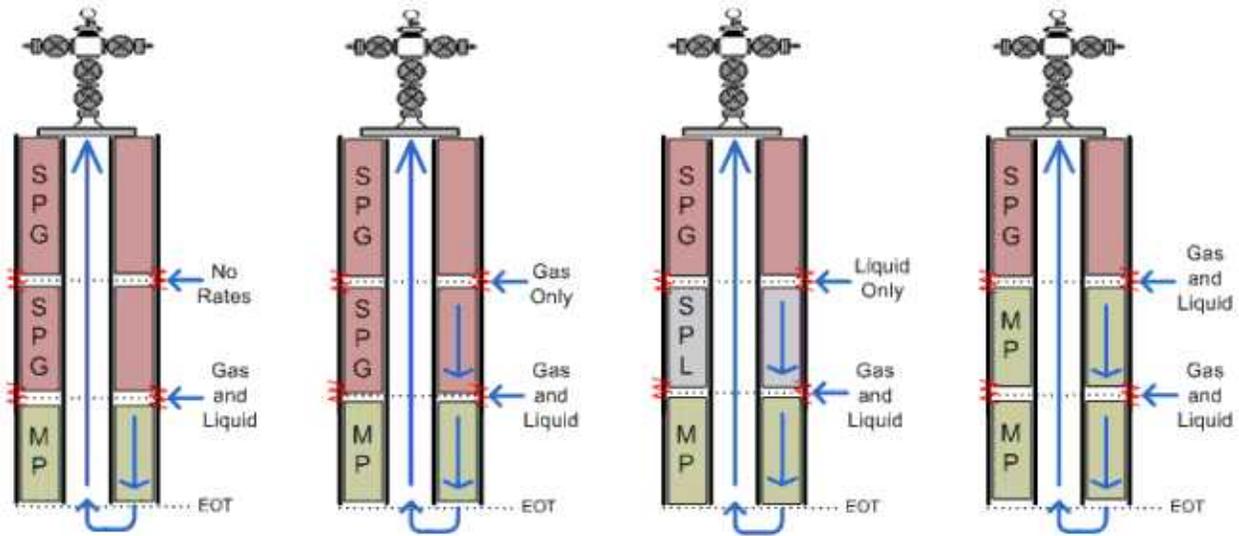


Legend
 Red background: Single Phase Gas (SPG)
 Purple background: Single Phase Liquid (SPL)
 Green background: Multiphase (MP)
 Blue lines: Direction of flow in the wellbore

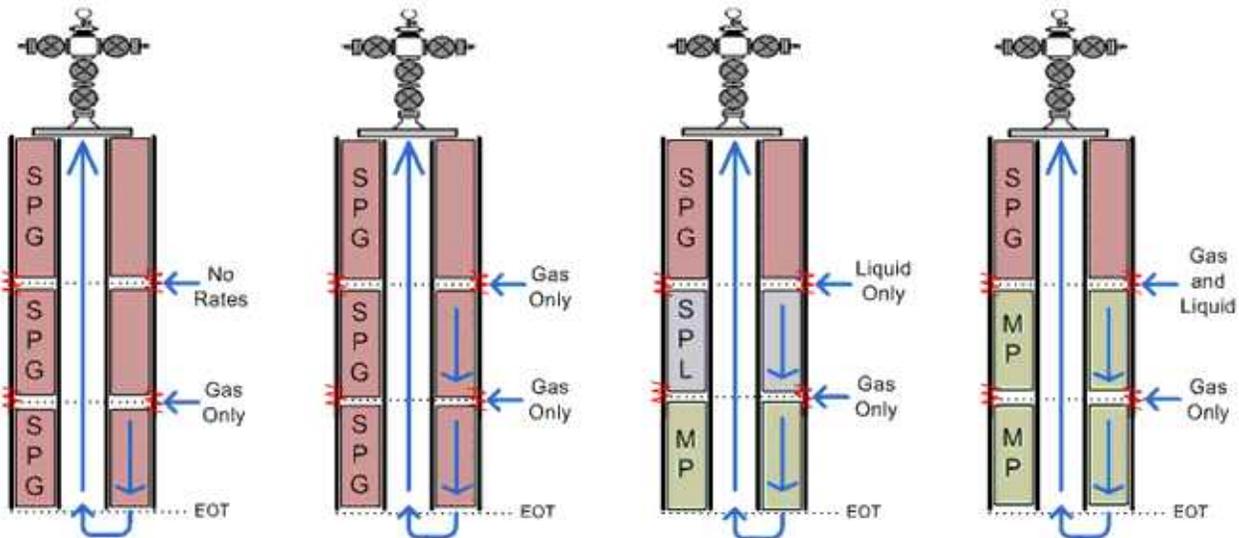
When additional layers are added to the system, then the rates must be combined in the order that they appear. For example, if a layer that was only flowing gas was followed by a layer that was only flowing water, then there would be a mix of gas and water at the second layer. This mix of gas and water would require a multiphase correlation to solve the pressure drop.

The following use cases show how rates would be mixed, if there were two layers above EOT. If more than two layers existed, then the same logic would be extended, with each subsequent layer experiencing the sum of the rates from the previous layers.

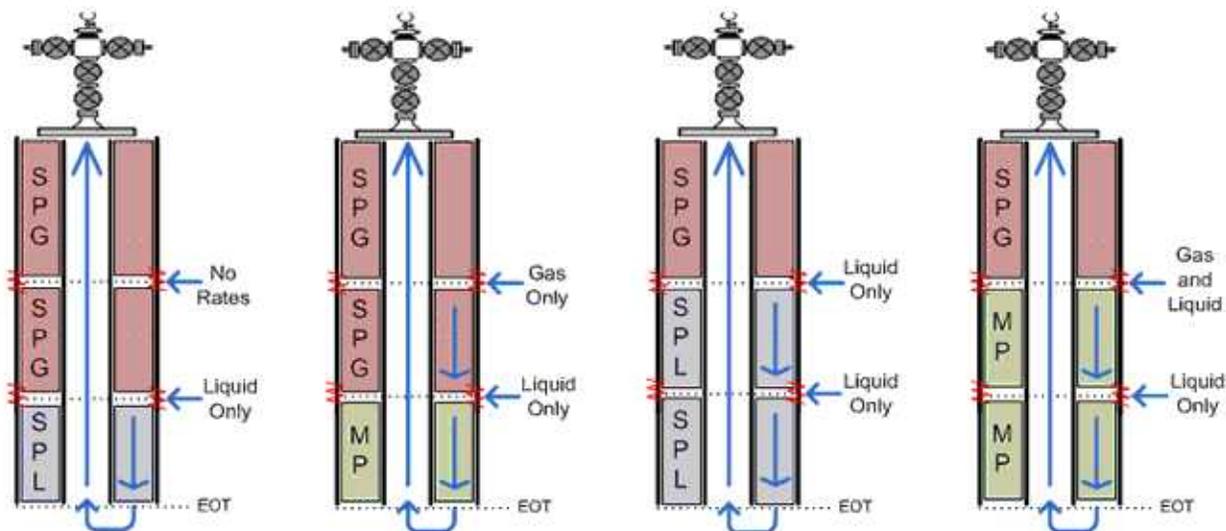
Group E: layer closest to EOT flowing gas & liquid | use cases 1 - 4



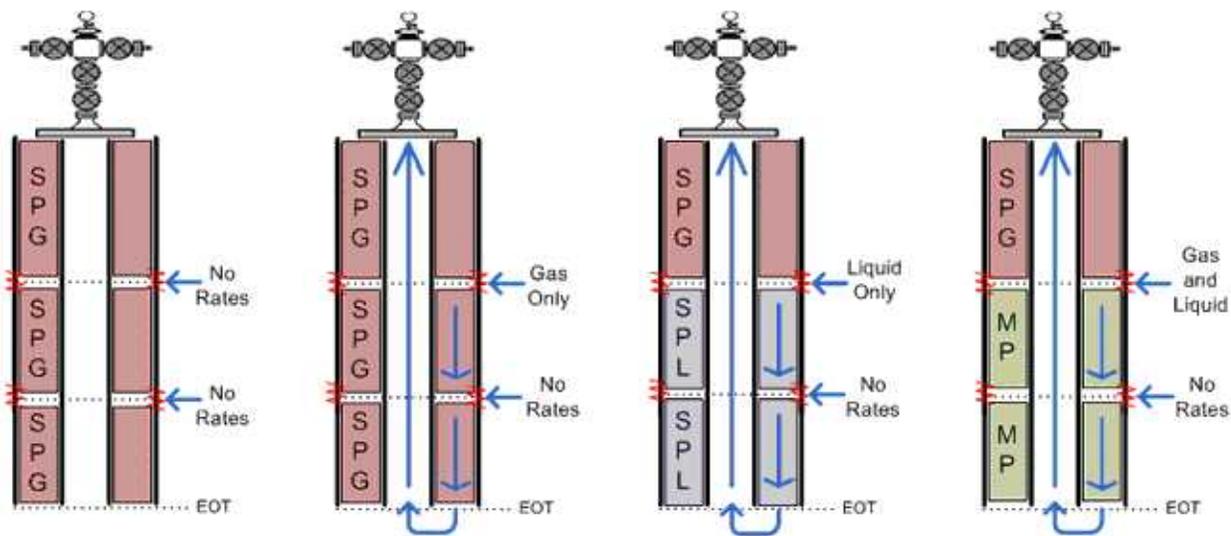
Group F: layer closest to EOT flowing gas only | use cases 5 - 8



Group G: layer closest to EOT flowing liquid only | use cases 9 - 12



Group H: layer closest to EOT shut-in (no rates) | use cases 13 - 16

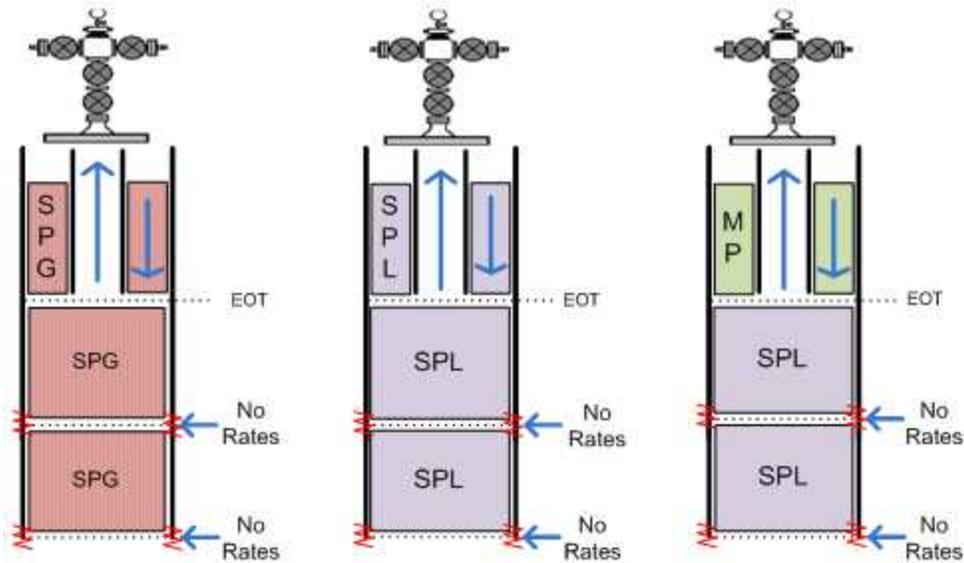


Examples: calculations below EOT

Pressure calculations for depths below EOT are nearly identical to the casing flow calculations described above. One minor difference is that the pressure and temperature at EOT are used as a starting point for all subsequent pressure calculations. The other difference is that there are additional rules for when all the layers below EOT are shut in.

Group I: deepest layer shut-in + all layers above shut-in

If every layer below EOT is shut in, then we must examine the flow conditions above EOT to determine the static column.



When all the layers below EOT have no rates, then the commingled rate for the layers above EOT must be examined. If there is any liquid production at all, then a static liquid column is assumed to exist from EOT to bottomhole. If there is no liquid production, then a static gas column is assumed.

Examples: calculations when the annulus is the flow path

When tubing exists, and the annulus is the flow path, all the produced fluids are assumed to travel upwards (similar to the situation when there is no tubing in the wellbore). In fact, the logic for annulus flow is almost identical to that of casing-only flow, with the major difference being the calculation of friction. Consequently, the logic examples shown in [casing flow examples](#) also apply to annulus flow.

Pressure source considerations

There are two pressure source considerations, which are described below.

Flow path = annulus, pressure source = casing

When the pressure source is the casing (annulus) wellhead pressure, then the order of events is to start at the wellhead and then calculate the pressure for each successive layer down. The only

difference for layers above and below EOT is the actual diameter used. For additional information, see [annular diameters](#).

Flow path = annulus, pressure source = tubing

When the pressure source is the tubing head pressure, then the mandatory first step is to calculate the pressure at the EOT. Once EOT pressure is known, then pressures can be calculated at any layer either above or below EOT.

Recombination

Many gas-condensate systems exist as a single-phase liquid in the reservoir. Condensation generally takes place at the separator, in the wellbore, or in the reservoir very near the wellbore. When modeling gas condensate systems at reservoir conditions, gas and condensate rates measured at surface conditions are combined into a single-phase rich gas using recombination.

The recombination calculation takes the volume of condensate, vaporizes it, and adds it to the gas volume to obtain a single-phase rich gas as it exists in the reservoir. A recombined gas gravity is also calculated for use in analytical models.

Given the specific gravity of measured separator gas, the condensate gas ratio (CGR), and the specific gravity of the condensate, the recombined gas gravity can be calculated using the following equation:

$$G_{Rec} = \frac{\frac{10^6 * G}{CGR} + 4602 \gamma_o + Q_{pa}}{\frac{10^6}{CGR} + V_{eq}}$$

Where:

$$Q_{pa} = 1.4599(p - 14.65)^{1.3394} G^{7.0943} \gamma_{API}^{1.1436} T^{-0.93446}$$

$$V_{eq} = 635.53 + 0.36182p^{1.0544} G^{5.0831} \gamma_{API}^{1.5812} T^{-0.79130}$$

The recombined gas rate is calculated using the following equation:

$$q_{Recombined} = q_{Measured} \left(1 + \frac{V_{eq}CGR}{10^6} \right)$$

The recombined gas rate factor (RGRF) is defined as recombined gas rate divided by the measured gas rate:

$$RGRF = \frac{q_{Recombined}}{q_{Measured}}$$

Relative permeability correlations

Relative permeability correlations

There are two types of relative permeability correlations: 2-phase models and 3-phase models.

2-phase models

Corey: This model assumes the wetting and non-wetting phase relative permeabilities to be independent of the saturations of the other phases, and requires only a single suite of gas / oil relative permeability data.

Honarpour: Developed using data from oil and gas fields in the continental US, Alaska, Canada, Libya, Iran, Argentina, and the United Arab Republic.

Generalized-Corey: Similar to the Corey correlation, but developed for a wider range of rock and wettability characteristics.

Custom Table: Allows you to enter laboratory measurements for 2-phase relative permeability.

3-phase models

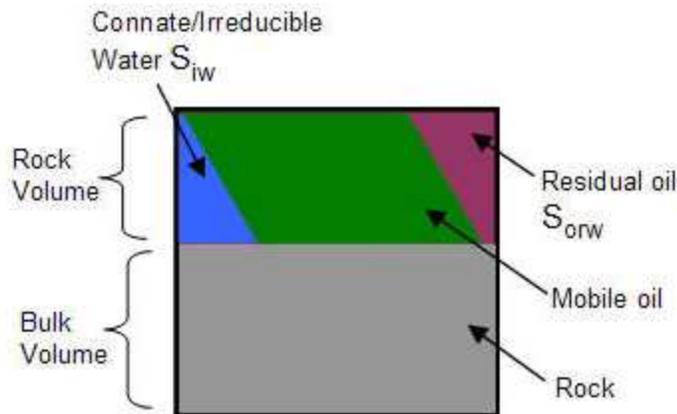
Stone 1: Based on the channel flow theory, and it is used widely in the industry as the benchmark for oil simulation. It is a better predictor than Stone 2 in low oil-saturation regions. More appropriate for water-wet systems, and not suited for intermediate wettability.

Stone 2: A modified version of Stone 1. It is a better predictor than Stone 1 in high-oil saturation regions. More appropriate for water wet-systems, and not suited for intermediate wettability.

Baker: Based on saturation-weighted interpolation between the 2-phase relative permeability values. Well suited for intermediate wettability or oil-wet systems.

Two-phase correlations

In a two-phase system, the fluids consist of oil and water, oil and gas, or gas and water. An example of an oil-water system is shown below:



Corey

This model assumes the wetting and non-wetting phase relative permeabilities to be independent of the saturations of the other phases and requires only a single suite of gas / oil relative permeability data.

Water / oil system

$$k_{ro} = \left[\frac{1-S_o}{1-S_{iw}} \right]^2 \left[1 - \left(\frac{S_o-S_{iw}}{1-S_{iw}} \right)^2 \right]$$

$$k_{rw} = \left[\frac{S_w-S_{iw}}{1-S_{iw}} \right]^4$$

Gas / oil system

$$k_{rg} = \left[\frac{S_g}{1-S_{org}} \right]^2 \left[1 - \left(\frac{1-S_g-S_{org}}{1-S_{org}} \right)^2 \right]$$

$$k_{ro} = \left[\frac{S_o-S_{org}}{1-S_{org}} \right]^4$$

Gas / Water System

$$k_{rg} = \left[\frac{S_g}{1-S_{iw}} \right]^2 \left[1 - \left(\frac{1-S_g-S_{iw}}{1-S_{iw}} \right)^2 \right]$$

$$k_{rw} = \left[\frac{S_w-S_{iw}}{1-S_{iw}} \right]^4$$

Honarpour

Developed using data from oil & gas fields in the continental US, Alaska, Canada, Libya, Iran, Argentina, and the United Arab Republic.

Sandstone

Water wet

$$k_{rw} = 0.035388 \left[\frac{S_w-S_{iw}}{1-S_{iw}-S_{orw}} \right] - 0.0108074 \left[\frac{S_w-S_{orw}}{1-S_{iw}-S_{orw}} \right]^{2.9} + 0.56556(S_w)^{3.6} (S_w - S_{iw})$$

Intermediate wet

$$k_{rw} = 1.5814 \left[\frac{S_w-S_{iw}}{1-S_{iw}} \right]^{1.91} - 0.58617 \left[\frac{S_w-S_{orw}}{1-S_{iw}-S_{orw}} \right]^{2.9} (S_w - S_{iw}) + 1.2484 \phi (1 - S_{iw}) (S_w - S_{iw})$$

Any wettability

$$k_{row} = 0.76067 \left[\frac{\left(\frac{S_o}{1-S_{iw}} \right) - S_{or}}{1-S_{orw}} \right]^{1.8} \left[\frac{S_o-S_{orw}}{1-S_{iw}-S_{orw}} \right]^{2.0} + 2.6318 \phi (1 - S_{orw}) (S_o - S_{orw})$$

$$k_{rog} = 0.98372 \left[\frac{S_o}{1-S_{iw}} \right]^4 \left[\frac{S_o-S_{org}}{1-S_{iw}-S_{org}} \right]^2$$

$$k_{rg} = 1.1072 \left[\frac{S_g-S_{gc}}{1-S_{iw}} \right]^2 k_{rgo} + 2.7794 S_{org} \left[\frac{S_g-S_{gc}}{1-S_{iw}} \right] k_{rgro}$$

Limestone

Water wet

$$k_{rw} = 0.0020525 \left[\frac{S_w - S_{iw}}{\phi^{2.15}} \right] - 0.051371 \left[\frac{S_w - S_{iw}}{k_{abs}^{0.43}} \right]$$

Intermediate wet

$$k_{rw} = 0.29986 \left[\frac{S_w - S_{iw}}{1 - S_{iw}} \right] - 0.32797 \left[\frac{S_w - S_{orw}}{1 - S_{iw} - S_{orw}} \right]^2 \left(S_w - S_{iw} \right) + 0.413259 \left[\frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}} \right]^4$$

Any wettability

$k_{row} = 1.2624 \left[\frac{S_o - S_{orw}}{1 - S_{orw}} \right] \left[\frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}} \right]^2$
$k_{rog} = 0.93752 \left[\frac{S_o}{1 - S_{iw}} \right]^4 \left[\frac{S_o - S_{org}}{1 - S_{iw} - S_{org}} \right]^2$
$k_{rg} = 1.8655 S_g \left[\frac{S_g - S_{gc}}{1 - S_{iw}} \right] k_{rgro} + 8.0053 (S_{org})^2 \left[\frac{S_g - S_{gc}}{1 - S_{iw}} \right] - 0.025890 (S_g - S_{gc}) \left[\frac{1 - S_{iw} - S_{org} - S_{gc}}{1 - S_{iw}} \right]^2 \left[1 - \frac{1 - S_{iw} - S_{org} - S_{gc}}{1 - S_{iw}} \right]^2 \left[\frac{k_{abs}}{\phi} \right]^{0.5}$

Generalized Corey

Similar to the Corey correlation, but developed for a wider range of rock and wettability characteristics. This correlation can be used to change the endpoints of water-oil and gas-liquid relative permeability curves while still retaining the shape of the curves.

Gas / oil system

$$k_{rog} = k_{rocw} \left[\frac{S_o - S_{iw} - S_{org}}{1 - S_{iw} - S_{org}} \right]^{n_{og}}$$

$$k_{rgo} = k_{rgro} \left[\frac{S_g - S_{go}}{1 - S_{gc} - S_{iw} - S_{org}} \right]^{n_g}$$

Gas / water system

$$k_{rg} = k_{rgcw} \left[\frac{S_g - S_{gc}}{1 - S_{gc} - S_{iw}} \right]^{n_g}$$

$$k_{rw} = k_{rwcg} \left[\frac{S_w - S_{iw}}{1 - S_{iw}} \right]^{n_w}$$

Water / oil system

$$k_{ro} = k_{rocw} \left[\frac{1 - S_w - S_{orw}}{1 - S_{iw} - S_{orw}} \right]^{n_{ow}}$$

$$k_{rw} = k_{rwrw} \left[\frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}} \right]^{n_w}$$

Three-phase correlations

Three-phase relative permeability can be generated from the two-phase relative permeability curves of the oil-water system, and the relative permeability curves of the gas-oil system. The two-phase curves represent the end curves when either the gas saturation or water saturation equals zero.

Stone I

This probability model estimates three-phase permeability data from laboratory measured two-phase data. It uses the channel flow theory in porous media to obtain a simple result for determining the relative permeability to oil in the presence of water and gas flow. The model implies that water-relative permeability and water-oil capillary pressure in three-phase systems are functions of water saturation alone, regardless of the relative saturations of oil and gas. Similarly, the gas-phase relative permeability and gas-oil capillary pressure are the same functions for gas saturation in the three-phase system as in the two-phase gas-oil system.

Stone I is widely used in the industry as the benchmark for oil simulation. It is a better predictor than Stone 2 in low oil saturation regions, is more appropriate for water-wet systems, and is not suited for intermediate wet systems.

$$S_o^* = \frac{S_o - S_{orw}}{1 - S_{iw} - S_{orw}}$$

$$S_w^* = \frac{S_w - S_{iw}}{1 - S_{iw} - S_{orw}}$$

$$S_g^* = \frac{S_g}{1 - S_{iw} - S_{orw}}$$

$$k_{ro} = k_{rocw} S_o^* \left[\frac{k_{row}(@S_w)}{k_{rocw}(1 - S_w^*)} \right] \left[\frac{k_{rog}(@S_g)}{k_{rocw}(1 - S_g^*)} \right]$$

Stone II

Stone's Model II is a modified version of Stone I. It is a better predictor than Stone 1 in high-oil saturation regions. It is more appropriate for water-wet systems, and is not suited for intermediate wet systems.

$$k_{ro} = k_{rocw} \left[\left(\frac{k_{row}}{k_{rocw}} + k_{rw} \right) \left(\frac{k_{rog}}{k_{rocw}} + k_{rg} \right) - \left(k_{rw} + k_{rg} \right) \right]$$

Baker

Baker's three-phase model is based on saturation-weighted interpolation between the two-phase relative permeability values. It is well suited for intermediate wet or oil-wet systems.

$$k_{ro} = \frac{(S_w - S_{iw})(k_{rocw}) + (S_g - S_{gc})(k_{rog})}{(S_w - S_{iw}) + (S_g - S_{gc})}$$

Water correlations

Correlations

Meehan: Generally applicable to calculate water properties while accounting for salinity.

Constant Properties: Allows you to enter values for the solution water gas ratio, water formation volume factor, water compressibility, and water viscosity at initial reservoir conditions.

Custom Table: Allows you to enter laboratory measurements for water properties.

Meehan (generally applicable)

Water compressibility is affected by the presence of solution gas, which evolves below the bubble point. The bubble point pressure of a gas-saturated brine is equal to the bubble point pressure of the co-existing oil. In a gas / water system, the water is considered to be at its bubble point at the initial reservoir pressure. Meehan presented an empirical correlation to determine the isothermal compressibility coefficient of gas-free water and gas-saturated water.

Compressibility

Gas-free water

$$c_{\tau, wf} = 10^{-6} (A + BT + CT^2)$$

where:

$$A = 3.8546 - 0.000134$$

$$B = -0.01052 + 4.77 * 10^{-7} p$$

$$C = 3.9267 * 10^{-5} - 8.8 * 10^{-10} p$$

Gas-saturated water

$$c_{\tau, wg} = c_{\tau, wf} (1.0 + 8.9 * 10^{-3} R_{sw})$$

where R_{sw} is the gas solubility in water

Saline solution

$$c_{\tau, w} = c_{\tau, wg} * C_z$$

$$C_z = 1.0 + (-0.052 + 2.7 * 10^{-4}T - 1.14 * 10^{-6}T^2 + 1.121 * 10^{-9}T^3) S^{0.7}$$

where S is the salinity of saline solution (brine)

General concepts

General concepts include the following:

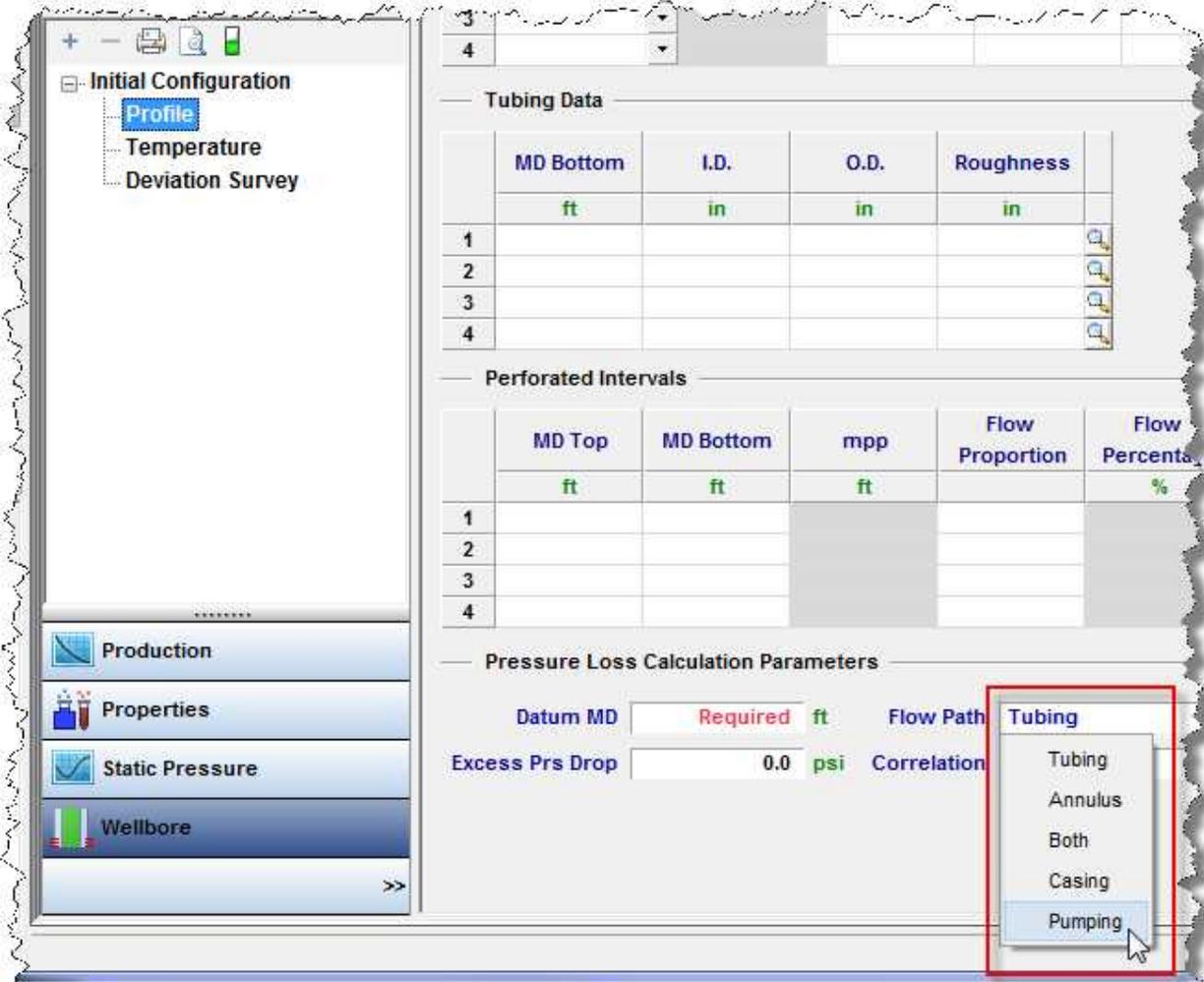
- [Automatic parameter estimation theory](#)
- [Capillary pressure](#)
- [Choke sizing](#)
- [Continuous time track](#)
- [Data diagnostics flow-chart](#)
- [Data diagnostics theory](#)
- [Dual porosity theory](#)
- [Equivalence of constant rate / pressure](#)
- [Fracture properties](#)
- [Geomechanical reservoir models](#)
- [GIS theory](#)
- [Interpolation theory](#)
- [Langmuir isotherm](#)
- [Material balance time theory](#)
- [Multilayered wells](#)
- [Oil PVT change during reservoir depletion](#)
- [Probabilistic](#)
- [Pseudo-pressure](#)
- [Pseudo-time](#)
- [Relative permeability](#)
- [Reserve evaluation](#)
- [Reservoir flow](#)
- [Reservoir fluid types](#)
- [Reservoir properties](#)
- [Shale properties](#)
- [Skin on fracture face](#)
- [Terminal / limiting decline rate](#)
- [Time-dependent skin](#)
- [Time to stabilization](#)
- [Water drive](#)
- [Well linking logic](#)
- [Wellbore storage](#)

Artificial lift

Pumping

For pumping wells with recorded liquid levels, use the Pumping flow path.

Open the [Wellbore editor](#), and click **Profile**. Click the **Flow Path** drop-down menu in the Pressure Loss Calculation Parameters section, and select **Pumping**.



The Pumping flow path makes the assumption that all liquids are pumped up the tubing (the wellbore requires a tubing string), that all gas is produced up the annulus, and that the pump is at the end of tubing (EOT). The Pumping flow path ignores tubing pressures; only entered or imported casing pressures are used to perform wellbore calculations. The final calculated sandface pressure is determined by breaking up the wellbore into individual sections.

A flowing row in the Production editor is a row that contains production information (gas or liquid). A non-flowing (shut-in) row has a value of "0" or null (that is, blank) for all volumes / rates.

With tubing landed below datum:

- The pressure drop is determined from the wellhead to the top of the liquid level using single-phase gas.

- Then, the hydrostatic pressure drop is determined from the top of the liquid level to the datum by multiplying the height of the liquid column by the liquid gradient.

With tubing landed above datum:

- The pressure drop is determined from the wellhead to the top of the liquid level using single-phase gas.
- The hydrostatic pressure drop is determined from the top of the liquid level to the end of tubing by multiplying the height of the liquid column by the liquid gradient.
- Finally, a multiphase flowing gradient is performed from the EOT to the datum.

The following columns are available in the Production editor:

- Liquid Level (MD)
- Liquid Level (TVD)
- Gas Gradient
- Water Gradient
- Oil Gradient
- Emulsion Gradient
- Average Liquid Gradient

Harmony Enterprise calculates and displays the average gradient for gas, oil, and water. Based on the water-oil ratio (WOR), it then calculates and displays an Emulsion Gradient (if applicable). Finally, Harmony Enterprise divides the entire hydrostatic pressure drop of the liquid column by the column height to determine the average liquid gradient. You can overwrite any and all gradients, with the exception of the emulsion gradient, which is a calculated value.

Calculated sandface pressure for a flowing row:

	Start Date	End Date	Gas Volume	Oil Volume	Water Volume	Casing Pressure	Pressure Source	Calculated Sandface Pressure	Liquid Level (MD)	Average Liquid Gradient	Gas Gradient	Oil Gradient	Water Gradient	Emulsion Gradient
	DD/MM/YYYY	DD/MM/YYYY	MMscf	stb	stb	psi(a)		psi(a)	ft	psi/ft	psi/ft	psi/ft	psi/ft	psi/ft
1	01/01/2012	02/01/2012	1.000	10.0	10.0	300.00	Casing Pressure	583.54	9500.00	0.340	0.011	0.340		

In cases where oil and water rates are entered, Harmony Enterprise assumes that when the well is flowing, only the lightest liquid (oil) is present in the static liquid column. Therefore, a water and emulsion gradient is not displayed, and the Average Liquid Gradient value is identical to the Oil Gradient.

Calculated sandface pressure for a shut-in row:

	Start Date	End Date	Gas Volume	Oil Volume	Water Volume	Casing Pressure	Pressure Source	Calculated Sandface Pressure	Liquid Level (MD)	Average Liquid Gradient	Gas Gradient	Oil Gradient	Water Gradient	Emulsion Gradient
	DD/MM/YYYY	DD/MM/YYYY	MMscf	stb	stb	psi(a)		psi(a)	ft	psi/ft	psi/ft	psi/ft	psi/ft	psi/ft
1	01/01/2012	02/01/2012	1.000	10.0	10.0	300.00	Casing Pressure	583.54	9500.00	0.340	0.011	0.340		
2	02/01/2012	03/01/2012	0.000	0.0	0.0	300.00	Casing Pressure	616.32	9500.00	0.351	0.007	0.340	0.417	0.379
3	03/01/2012	04/01/2012	0.000	0.0	0.0	300.00	Casing Pressure	814.67	9000.00	0.374	0.007	0.358	0.396	0.377
4	04/01/2012	05/01/2012	0.000	0.0	0.0	300.00	Casing Pressure	995.70	8500.00	0.372	0.008	0.351	0.403	0.377
5	05/01/2012	06/01/2012	0.000	0.0	0.0	300.00	Casing Pressure	1187.06	8000.00	0.376	0.007	0.357	0.400	0.379
6	06/01/2012	07/01/2012	1.000	10.0	10.0	300.00	Casing Pressure	583.54	9500.00	0.340	0.011	0.340		

The first shut-in row sets the height of the static oil column. If the liquid level rises, the oil column also rises, followed by an emulsion. The WOR of the last producing row is used to calculate the emulsion gradient for all of the following shut-in rows in this period until the well begins to flow again.

Note: Gradients are not calculated when the pressure source is Gauge depth pressure.

Gas lift

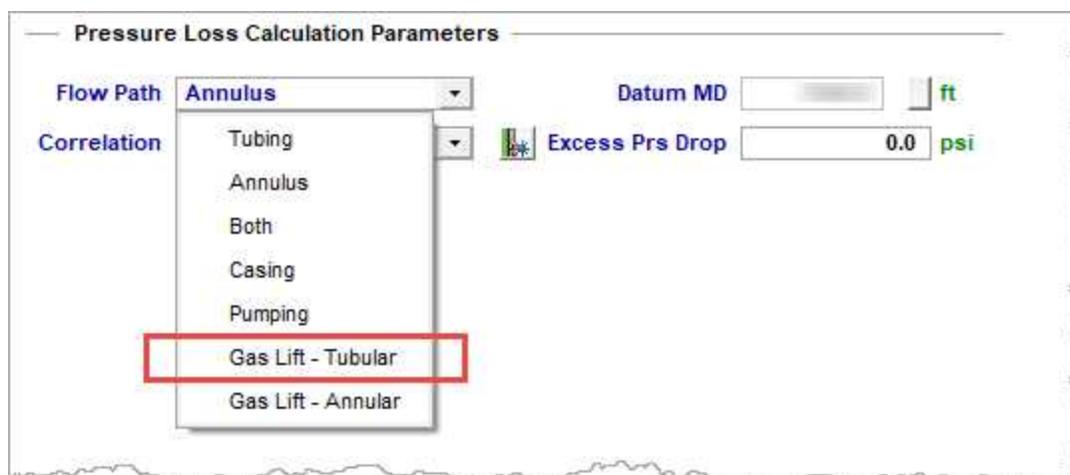
Harmony Enterprise supports two types of gas lift:

1. Tubular — production up the tubing (gas injected down the casing annulus).
2. Annular — production up the casing annulus (gas injected down the tubing).

Tubular

To select the Gas Lift -Tubular flow path for your wellbore configuration:

Open the Wellbore editor. Click the **Flow Path** drop-down menu in the Pressure Loss Calculation Parameters section, and select **Gas Lift - Tubular**.



Additional options become available.

The screenshot shows a software interface for calculating pressure loss. It is divided into two sections: "Pressure Loss Calculation Parameters" and "Gas Lift Parameters".

Pressure Loss Calculation Parameters:

- Flow Path: Gas Lift - Tubular (dropdown menu)
- Datum MD: 7500.0 ft (text input)
- Correlation: Gray (dropdown menu)
- Excess Prs Drop: 0.0 psi (text input)

Gas Lift Parameters:

- Use Valve & Packer: (checkbox, highlighted with a red box)
- Valve Depth: 4990.0 ft (text input)

You can choose to model your gas lift system conventionally, with an operating valve and a packer, or as a “poor boy” system with no packer / valve.

Conventional gas lift

To model your gas lift system conventionally, click the **Use Valve & Packer** box. You must also specify the depth of the operating valve. If you do not specify a depth, Harmony Enterprise uses a default valve location 10 feet above EOT. With a packer in place, you must use tubing pressure as your pressure source. Sandface pressures cannot be calculated using the casing side pressure source.

The wellbore calculations assume that none of the injected gas is lost to the reservoir(s), and that all of it is returned up the tubing. Sandface pressure calculations occur as follows:

- The pressure drop from the surface to the operating valve is determined using the sum of all production rates, plus the rate of gas injection.
- The pressure drop from the operating valve to the datum(s) is determined using production rates only.

"Poor boy" gas lift

To model your gas lift system as “poor boy”, deselect the **Use Valve & Packer** option. Because there is no packer in place, it is possible to use either casing or tubing as your pressure source in order to perform sandface pressure calculations.

Just as in the conventional case, the wellbore calculations assume that none of the injected gas is lost to the reservoir(s). Note that pressure calculations differ depending on your pressure source (that is, tubing or casing).

For tubing, the calculations occur as follows:

- The pressure drop from the surface to EOT is determined using the sum of the production rates, plus the rate of gas injection.
- The pressure drop from EOT to the datum(s) is determined using production rates only.

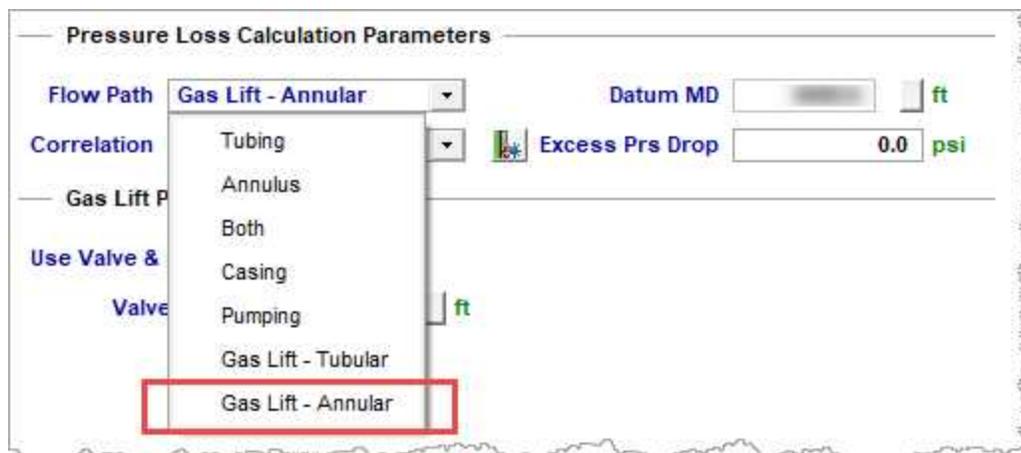
For casing side pressure, the calculations occur as follows:

- The pressure drop from the surface to EOT (or the most shallow layer above EOT, if applicable) is determined using only the gas injection rate.
- If there are layers above EOT, the pressure drop from the most shallow layer above EOT to EOT is determined using the gas injection rate, plus the rate of any fluids produced from the layer(s) above EOT.
- The pressure drop from EOT to the remaining datum(s) is determined using only the production rates from the layers below EOT.

Annular

To select the Gas Lift - Annular flow path for your wellbore configuration:

Open the [Wellbore editor](#). Click the **Flow Path** drop-down menu in the Pressure Loss Calculation Parameters section, and select **Gas Lift - Annular**.



The Gas Lift parameters are identical to those of [Gas Lift – Tubular](#).

Note: No perforated intervals can exist above EOT.

Conventional (with valve and packer)

With this method, a valve can be set at almost any depth in the tubing. Because of this, we assume that there is a “packer” at the toe of the tubing string. Furthermore, you must use casing pressure as your pressure source.

The wellbore calculations assume that none of the injected gas is lost to the reservoir(s), and that all of it is returned up the annulus. Sandface pressure calculations occur as follows:

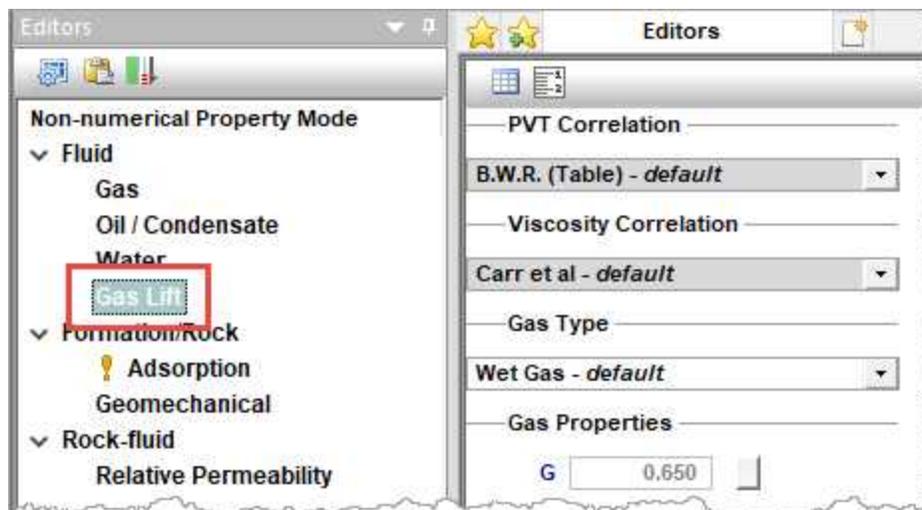
- The pressure drop from the surface to the operating valve is determined using the sum of all production rates, plus the rate of gas injection.
 - Since the flow path is the annulus, our calculations take into account the additional friction caused by both pipe walls. For more information, see [annular diameters](#).
- The pressure drop from the operating valve to the datum(s) is determined using production rates only.

"Poor boy" (no valve or packer)

For a general description of the process we use, see "[poor boy](#)" for tubular gift lift. Remember that the flow direction is reversed.

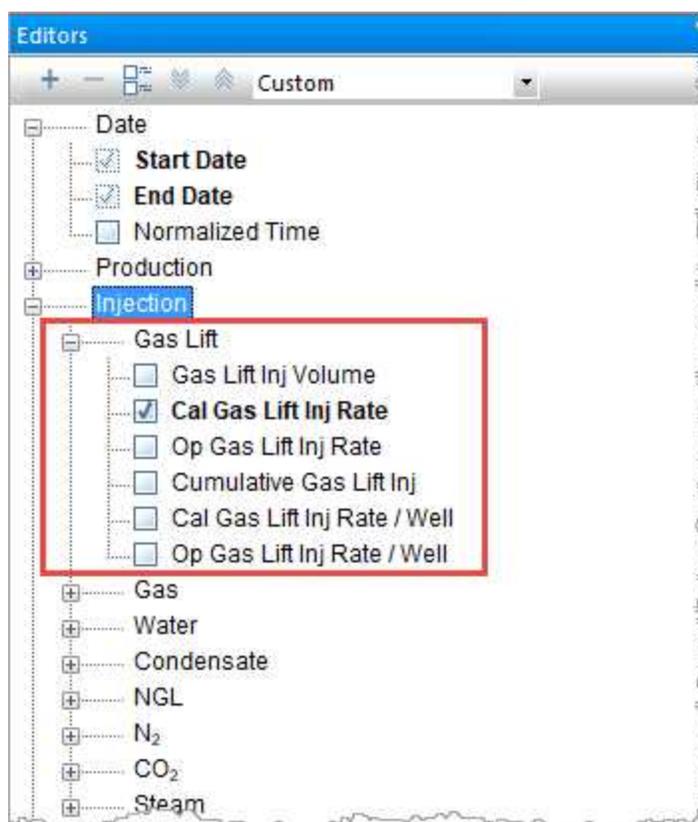
Entering data into the Properties editor

The properties of the injected gas may be different from the properties of the produced gas. You can enter your gas lift properties separately from produced gas properties in the [Properties editor](#).



Entering rates into the Production editor

Gas lift injection is treated differently than gas injection. If you want to model your well on gas lift, you must ensure that the injection rates (or volumes) are entered in the [Production editor](#) in the Gas Lift Injection fields, *not* the Gas Injection fields.



There are differences between net produced gas and gross produced gas:

- Under the Production node, click **Gas**. This is gas produced from the reservoir. If you have gas lift operations, this is a “net produced gas”; which is gas produced from the well minus the gas injected for gas lift.
- Under the Injection node, click **Gas Lift**. This is the gas injected into the well-bore for gas lift injection purposes only.

Therefore, in the following screenshot, the total gas received at the wellhead (gross produced gas) is the sum of Gas Volume and Gas Lift Inj Volume.

	Start Date	End Date	Gas Volume	Oil Volume	Gas Lift Inj Volume	Tubing Pressure	Casing Pressure	Active Pressure	Pressure Source	Calculated Sandface Pressure
	MM/DD/YYYY	MM/DD/YYYY	MMscf	stb	MMscf	psi(a)	psi(a)	psi(a)		psi(a)
1	05/15/2009	05/16/2009	5,000	500.0	0.000	1000.00	1500.00	1000.00	Tubing Pressure	2454.40
2	05/16/2009	05/17/2009	5,000	500.0	1.000	1000.00	1600.00	1000.00	Tubing Pressure	2572.90
3	05/17/2009	05/18/2009	5,000	500.0	2.000	1000.00	1700.00	1000.00	Tubing Pressure	2710.13
4	05/18/2009	05/19/2009	5,000	500.0	3.000	1000.00	1800.00	1000.00	Tubing Pressure	2860.28
5	05/19/2009	05/20/2009	5,000	500.0	4.000	1000.00	1900.00	1000.00	Tubing Pressure	3019.90

Automatic parameter estimation theory

Automatic parameter estimation (APE) is a mathematical process, known as multi-variable optimization, which automatically adjusts a specified set of function parameters to minimize error between the function and measured data. The mathematical function being minimized is called the objective function.

With analytical modeling in Harmony Enterprise, the objective function is calculated as follows:

- If Calculate Pressure mode is used:

$$E_{avg} = \frac{\sum_i \left(\frac{|(p_{calc})_i - (p_{hist})_i|}{(p_{hist})_i} w_i \right)}{\sum_i w_i}$$

- If Calculate Rate mode is used:

$$E_{avg} = \frac{\sum_i \left(\frac{|(q_{calc})_i - (q_{hist})_i|}{(q_{hist})_i} w_i \right)}{\sum_i w_i}$$

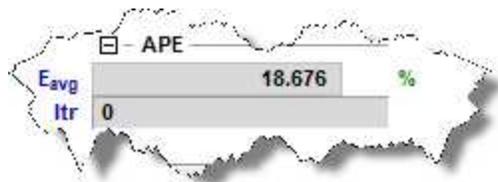
Where (summation is done for all history points, and i is the number of the point):

- $(p_{hist})_i$ — historical pressure for the i -th point
- $(p_{calc})_i$ — calculated pressure for the i -th point
- $(q_{hist})_i$ — historical rate for the i -th point
- $(q_{calc})_i$ — calculated rate for the i -th point
- w_i — weight for the i -th point

Note: $w_i = 0$ if the point is deselected; $w_i = 1$ if the point is selected; $w_i = 10$ if the point is weighted.

If Calculate Both mode is used, the objective function is calculated as the sum of the objective functions for Calculate Pressure and Calculate Rate modes.

E_{avg} reflects the difference between calculated and historical data; therefore a smaller E_{avg} indicates a better history match. The value of the objective function E_{avg} is displayed under the APE group in the Analytical Model pane.



Over an iterative process, the selected modeling parameters are adjusted using the Mead (Simplex) optimization method to minimize the objective function.

Automatic parameter estimation should not be used exclusively because it is possible to find several sets of parameters that yield an acceptable model match. In other words, the solution can be non-unique. It is always recommended to start with parameters obtained from diagnostic analyses, and then fine-tune these parameters manually to obtain a close match. You can use APE for unknown parameters, or parameters which are not known with confidence. The more parameters that are selected for APE (or fitting), the longer the fitting process will take, with a greater chance of finding non-unique solutions. Note that if you include more data points in the fit, it will reduce performance.

Mead (Simplex)

This is a variation of the downhill Simplex method. The Simplex routine is a non-linear regression algorithm used for APE for reservoir and well parameters (k , s , C_D , etc.) when modeling pressure-transient data. The Mead method only requires function evaluations of the objective function, and not the derivatives.

To achieve greater convergence, the downhill Simplex method is modified by imposing constraints on the parameters during the search. Estimates of the parameters are always checked against preset maximum and minimum values for each parameter. Once the routine has converged on some parameters, it is restarted, with a slight perturbation away from the final values, and then it is allowed to converge again. This ensures that the parameter estimates are not the result of some local minimum in the residual, but rather a more global minimum.

Compared to other non-linear regression methods, this method is not always very efficient because it can require a large number of function evaluations. This tends to make it extremely slow in some cases. However, it is straightforward and not encumbered by the requirement of derivatives, and hence tends to be more robust under any conditions.

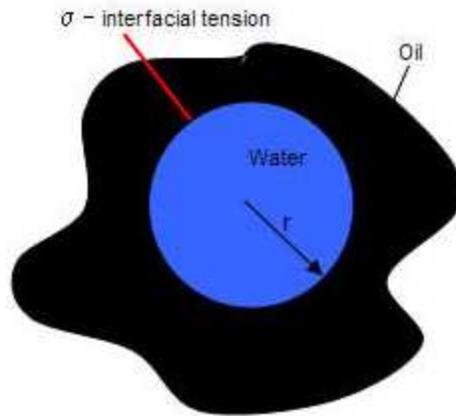
Capillary pressure

Capillary pressure (P_c) is the pressure difference across the interface between two immiscible fluids arising from capillary forces. These capillary forces are surface tension and interfacial tension. In porous media, the capillary pressure is the difference between the pressure in the non-wetting phase and the pressure in the wetting phase. It is defined by:

$$P_c = p_{non-wettingphase} - p_{wettingphase}$$

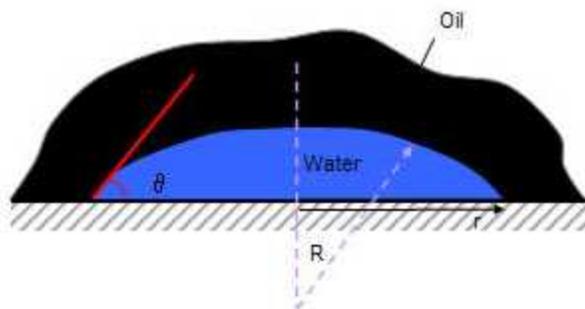
In oil-water systems, water is typically the wetting phase; while for gas-oil systems, oil is typically the wetting phase.

In a drop of water in oil, the interfacial tension is denoted by σ and has the following capillary pressure:



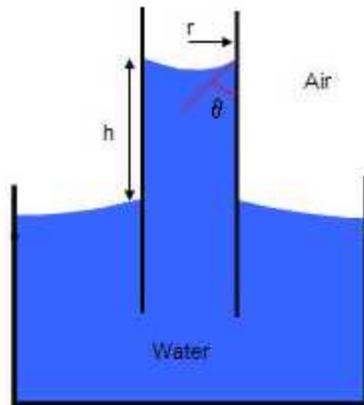
$$P_c = p_w - p_o = \Delta p = \frac{2\sigma}{r}$$

A drop of water on a surface with contact angle θ (where $\theta < 90^\circ$ is water wet) has the following capillary pressure:



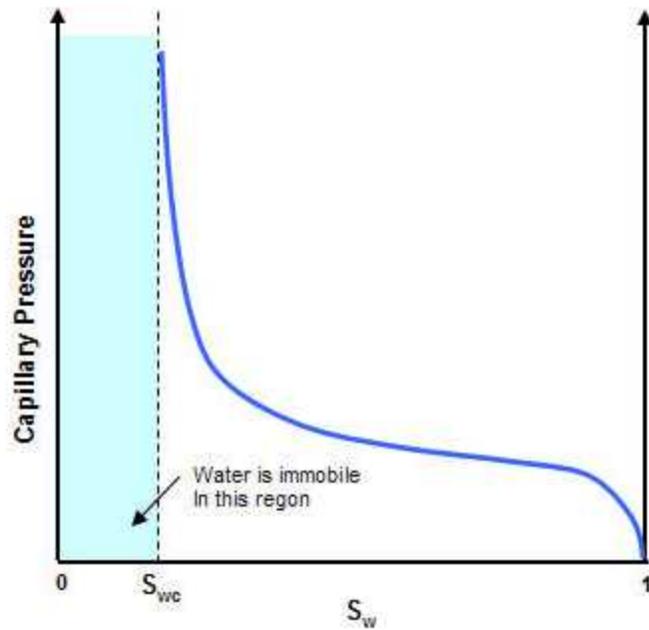
$$P_c = p_w - p_o = \Delta p = \frac{2\sigma \cos(\theta)}{r}$$

Water in a capillary tube with contact angle θ , where h is the height the water rises, has the following capillary pressure:



$$P_c = p_{air} - p_o = \Delta p = \frac{2\sigma \cos(\theta)}{r} = (\rho_w - \rho_{air})$$

The shape of the curve depends on pore sizes, size distribution, and fluid properties. The permeability of the reservoir rock can alter the capillary pressure curve. If the value of the permeability is lower, the pore size is smaller, and the capillary pressure is higher.



Choke sizing

Choke sizing applies to single-phase flow and multiphase flow.

Specific heat ratio

$$\kappa = \frac{C_p}{C_v}$$

where:

C_p = specific heat capacity of gas at constant pressure

C_v = specific heat capacity of gas at constant volume

Both of the above are evaluated at upstream pressure and temperature.

Single-phase flow

Rawlins-Schellhardt

Rawlins and Schellhardt developed a form of equation for gas flow through chokes under critical flow conditions that is dependent only on upstream pressure. Rawlins and Schellhardt based their equation on ideal gas at a standard pressure of 14.4 psia. Correction for non-ideality and for a standard pressure other than 14.4 psia is included in the following equation:

$$q_g = \frac{C_f (14.4 / P_{sc}) P_1}{1000 \sqrt{\gamma_g z_1 T_1}}$$

where

q_i = gas flow rate, MMscfd

P_1 = upstream pressure, psia

T_1 = upstream temperature, °R

γ_g = gas specific gravity (air = 1.0)

z_1 = gas compressibility factor at upstream conditions

C_f = choke flow coefficient

Multiphase flow

Ashford-Pierce

Ashford and Pierce developed a correlation specifically describing multiphase flow through safety valves and tested it against field data. Their correlation has the form:

$$q_o = 3.51 C_d D_c^3 \alpha_{10} \beta_{10}$$

with

$$\alpha_{10} = \frac{1}{\sqrt{B_o + F_{wo}}}$$

$$\beta_{10} = \frac{\left[\left(\frac{k}{k-1} \right) T_1 z_1 (R_p - R_s) \left(1 - y^{\frac{(k-1)}{k}} \right) + 198.6 P_1 (1-y) \right] \sqrt{\gamma_o + 0.000217 \gamma_g R_s + F_{wo} \gamma_w}}{\left[198.6 + \frac{T_1 z_1}{P_1} (R_p - R_s) y^{-\frac{1}{k}} \right] \left[\gamma_o + 0.000217 \gamma_g R_p + F_{wo} \gamma_w \right]}$$

where:

C_d = choke discharge coefficient

D = choke diameter, 64th of an inch

B_o = oil formation volume factor, rbbl / bbl

F_{wo} = water oil ratio, bbl / bbl

T_1 = upstream temperature, *R

P_1 = upstream pressure, psia

z_1 = gas compressibility factor at upstream conditions

R_F = producing gas oil ratio, scf / bbl

R_s = solution gas oil ratio, scf / bbl

γ = ratio of downstream pressure to upstream pressure, P_2 / P_1

$k = C_F / C_s$

γ_o = oil specific gravity (pure water = 1.0)

γ_w = water specific gravity (pure water = 1.0)

γ_g = gas specific gravity (air = 1.0)

This relationship applies both at and above the critical pressure ratio, γ_c .

Ashford and Pierce further define the critical pressure ratio, γ_c , as

$$\gamma_c = \frac{1}{R_1} \left\{ \frac{2R_1}{k(1+R_1\gamma_c^{-\rho})} \left[\left(\frac{R_1}{b} \right) (1-\gamma_c^b) - \gamma_c + 1 \right] \gamma_c^{-e} - 1 \right\}$$

where

$$b = \frac{k-1}{k}$$

$$e = \frac{k+1}{k}$$

As this is implicit in γ_c it must be solved iteratively.

The Ashford-Pierce relationship cannot directly be applied here because oil may or may not be one of the flowing phases. However, their relationship for the fluid velocity downstream of the choke gives rise to an alternative approach that is amenable to solution with gas plus one or more liquid phases present:

$$u_2 = \sqrt{\left(\frac{2k}{k-1}\right) g_c \left(\frac{1}{\rho_{f1}} - \frac{1}{\rho_l}\right) P_1 \left(1 - \gamma^{\frac{(k-1)}{k}}\right) + 2g_c \frac{1}{\rho_l} P_1 (1 - \gamma)}$$

where:

u_2 = downstream fluid velocity, ft / s

P_1 = upstream pressure, psia

$k = C_F / C_S$

γ = ratio of downstream pressure to upstream pressure, P_2 / P_1

g = mass weight equivalence factor, 32.174 lb ft / lb ft / ls s²

ρ_{f1} = total fluid density at upstream conditions, lb / ft³

ρ_l = liquid density, lb / ft³

Assuming critical flow in the choke throat, the downstream pressure and fluid velocity can be calculated, and with the latter plus the produced fluid ratios, the mass flowrate of each phase is obtainable.

For more information, see [references](#).

Achong

Achong updated Gilbert's relationship on the basis of data from oil wells in the Lake Maracaibo field of Venezuela. The rate of multiphase flow through a choke and the upstream pressure are, according to Achong, correlated by the following relationship:

$$P_1 = \frac{3.829q_l R_p^{0.65}}{D_c^{1.88}}$$

where:

P_1 = upstream pressure, psia

q_l = liquid flowrate, bbl / d

R_p = producing gas liquid ratio, scf / bbl

D_c = choke diameter, 64th of an inch

For more information, see [references](#).

Baxendell

Baxendell's correlation linking the rate of multiphase flow through a choke and the upstream pressure – and fundamentally an update of the Gilbert correlation – is:

$$P_1 = \frac{9.552q_1R_p^{0.546}}{D_c^{1.93}}$$

where:

P_1 = upstream pressure, psia

q_1 = liquid flowrate, bbl / d

R_p = producing gas liquid ratio, scf / bbl

D_c = choke diameter, 64th of an inch

For more information, see [references](#).

Gilbert

Gilbert developed a generalized correlation based on data from flowing oil wells in the Ten Section field of California. The rate of multiphase flow through a choke and the upstream pressure can be correlated, according to Gilbert, by the following relationship:

$$P_1 = \frac{10q_1R_p^{0.546}}{D_c^{1.88}}$$

where:

P_1 = upstream pressure, psia

q_1 = liquid flowrate, bbl / d

R_p = producing gas liquid ratio, scf / bbl

D_c = choke diameter, 64th of an inch

For more information, see [references](#).

Ros

The rate of multiphase flow through a choke and the upstream pressure are, according to Ros on the basis of Gilbert's and other prior work, correlated by the following relationship:

$$P_1 = \frac{17.4q_1 R_p^{0.5}}{D_c^2}$$

where:

P_1 = upstream pressure, psia

q_1 = liquid flowrate, bbl / d

R_p = producing gas liquid ratio, scf / bbl

D_c = choke diameter, 64th of an inch

For more information, see [references](#).

Continuous time track

This feature is used to adjust your data depending on your shut-in conditions. It is extremely important that you use this feature correctly, as your volume and rate data is influenced by this setting. The time track on import is interpreted based on the state of this setting:

- If this option is *selected*, no adjustment to the time track is made. The start dates in Harmony Enterprise match the data imported.
- If this option is *deselected*, Harmony Enterprise analyzes the time track. If the time between two reported dates is greater than a day, but less than a month, a day is assumed. If the time is greater than a month, but less than a year, a month is assumed.

The Continuous Time Track checkbox is located in the [Import Options pane](#) (Import Data dialog box) and the [Select Wells to Import dialog box](#). By default, this option is selected for cumulative time.

Example: demonstrating the effect of the Continuous Time Track option

Given the following data, there are noticeable differences in the values Harmony Enterprise uses based on whether or not you select this feature:

Timestep (t)	Rate (q)
1	10
2	20
4	30
5	40

If you select the Continuous Time Track option, Harmony Enterprise uses the following values:

t_{start}	t_{end}	Rate (q)	Volume (V)	Cumulative Volume (Q)
1	2	10	10	10
2	4	20	40	50
4	5	30	30	80
5	6	40	40	120

If you deselect the Continuous Time Track option, Harmony Enterprise uses the following values:

t_{start}	t_{end}	Rate (q)	Volume (V)	Cumulative Volume (Q)
1	2	10	10	10
2	3	20	20	30
3	4			30
4	5	30	30	60
5	6	40	40	100

Data diagnostics theory

The analysis of production data to determine reservoir characteristics, completion effectiveness, and hydrocarbons-in-place is becoming more prevalent. The methods of analysis have been

documented and verified in numerous publications. The concepts underlying modern production data analysis are the same as pressure transient analysis. Even though both these domains use the same underlying theory of fluid flow through porous media and can determine the same variables (permeability, skin, reservoir size), it should not be assumed that they can replace each other. Pressure transient analysis and production data analysis must be viewed as complementary and not substitutes for each other. Pressure transient analysis deals mostly with “high frequency / high resolution” shut-in data, while production data analysis deals with “low frequency / low resolution” flowing data. This in itself, presents significant differences in data quality and interpretations.

Like all mathematical solutions, production data analysis methods are subject to numerous assumptions, which often can be justified. In this case, if the data is complete, consistent and of good quality, meaningful results can be obtained. However, if the quality of the data is questionable, then the production data analysis methods should be used with caution. In this case, the analyst’s ability to filter out the bad data and extract the true reservoir signal becomes extremely important. As mentioned by Anderson et al. 2006, blind application of production data analysis methods without consideration of data quality issues can lead to misinterpretation of the reservoir characteristics. An analyst, who is not experienced in recognizing such inconsistencies, can obtain an answer that appears to be mathematically correct, yet be completely wrong because of using “bad data” for analysis.

There is no complete set of criteria that covers all of the challenges and pitfalls in production data analysis. Some inconsistencies in data measurement or reporting are more critical than others, while the same issue may be critical in one situation, but not in another. This makes data diagnostics complicated and very dependent on the expertise of the analyst. Nonetheless, there are some issues that are worse than others, and cause “bad” or inconsistent production data a lot of the time. Some of the more common issues are listed below:

- **Missing flowing pressures** — Even though the rate history is carefully obtained from daily records, the pressure history is infrequent, inaccurate, or often non-existent.
- **Missing flow rates** — Even though the flowing pressure of an individual well is obtained accurately and frequently from permanently installed downhole gauges, the corresponding flow rate is often non-existent, or has been pro-rated on a monthly basis from a group meter of several wells.
- **Rate or pressure averaging** — Often the flow rate and/or the flowing pressure are measured at high frequency (every minute), but for data storage efficiency, are averaged to daily quantities. Depending on the rate variations during that period, this may result in meaningless numbers.

- **Wrong initial pressure** — The initial pressure is unknown or wrong, especially in tight gas or infill drilling.
- **Liquid loading** — The calculation of sandface pressures is wrong due to the unknown “standing liquid column” in the wellbore.
- **Wrong pressure source and flow path** — If the source of the wellhead pressure measurement or the flow path are specified incorrectly (tubing, annulus or both, or changing from one to the other) the calculated sandface pressures will be incorrect.
- **Wrong production data** — Rate allocations to individual wells based on group metering can be in error, as the distribution is based on infrequent tests.
- **Wrong production data** — The water production rate of individual wells is often poorly monitored or misreported. While small quantities of water may have little effect on the reservoir interpretation, they can have a significant effect on the wellbore performance and on the calculation of sandface pressures from wellhead data.
- **Significant increase in water / gas ratio** — When the water-gas ratio is high (>100 bbl/MMscf), the assumption of single-phase Darcy flow in the reservoir may not be valid, or the skin due to water coning may be variable, which affects the validity of the permeability and skin calculations.
 - Operational modifications:
 - Opening up of new perforations / shutting off old perforations
 - Refracturing of the well
 - Changing tubulars
 - Changing flow path
- **Wrong location of pressure gauge** — Often the only flowing pressure available is the pressure downstream of the choke. If the choke is wide open, this pressure is usable, but if the choke is being used to control the flow rate, then the downstream pressure is not of much value.
- **Wrong rate and pressure synchronization** — The original rate and pressure data often have different time tracks, and if they have not been synchronized properly, the interpretation may be invalid.

Sometimes a simple look at the reported production data (flowing pressure, gas and liquid flow rates and time) can reveal obvious or potential inconsistencies, or provide insight for interpretation. Here are some examples:

- If the flow rate suddenly increases, the flowing pressure should abruptly decrease correspondingly.
- If the flow rate is below the “critical liquid lift velocity” calculated using Turner correlation (Turner et al. 1969) or Coleman correlation (Coleman et al., 1991), there is the likelihood of liquid loading.
- If the tubing and casing pressure profiles are diverging, it is an indication of liquid load-up.
- The pressure is measured every minute but reported daily, along with the daily average rate. If there have been interruptions or significant rate changes during the 24-hour interval, an average daily rate is meaningful, but an average daily pressure is not.
- Sometimes the flow rate is pro-rated from a group-meter measurement instead of being measured at the individual well. The pro-rating formula honors the total production from all the wells, but may be completely incorrect at the individual well level, especially when there have been undocumented production disruptions at various wells.
- A rapid increase in the water-gas ratio could indicate water coning, and wellbore operational problems.
- A rapid decrease in the water-gas ratio or condensate-gas ratio could indicate liquid loading in the wellbore.
- A high frequency of scatter in production rates, pressures, the water-gas ratio, or condensate-gas ratio can indicate unstable flow in the well and/or unstable operating conditions.
- Flat (constant) liquid production rates, with large step changes, usually indicate infrequent measurement. The presence of this kind of data can make the quality of the calculated sandface pressures low, even if the wellhead pressures are of high quality.
- No liquid rates are reported, yet either the pressure data indicates “slugging”, or it is a known fact that liquids are being produced. In this case, the quality of the calculated sandface flowing pressure may not be high, even if the wellhead pressures are of high quality.
- Flat (constant) pressures with step changes usually indicate infrequent pressure measurement. This means that one pressure is recorded per week or month, and then it is reported as a constant value until another reading is taken.
- Straight-line trends in pressures or rates usually indicate infrequent measurements and interpolation between them (rather than actual measurement).

Note: For additional data diagnostic examples, see the [data diagnostics flowchart](#).

When an analysis is performed, the analyst must always review the interpretation to make sure it makes sense. This is the ultimate test and must never be avoided. Although it is preferable to identify and eliminate inconsistent data before the analysis is undertaken, sometimes inconsistencies do not become evident until after the analysis has been completed. For example, a sudden change in the slope of the flowing material balance plot (p/Z plot) is a diagnostic that depends on information about original-gas-in-place, which is obtained from interpretation.

Recognizing the fact that the analysis and interpretation of production data is influenced significantly by the quality and consistency of the data, it is the objective of this topic to develop a series of diagnostic plots and guidelines that can help analysts to identify “bad data” and prevent misleading answers resulting from analyzing poor-quality data. The diagnostic plots are independent of any interpretations as they are considered pre-analysis diagnostics.

To achieve the objective of this topic, a number of diagnostic plots are proposed. These plots are then used in a number of case studies using field examples. The intent was to investigate if these diagnostics plots could differentiate between “good data” and “bad data”. The results of this study allow production engineers to recognize poor-quality data, and avoid being misled by their results, or at least to make a reasonable judgments as to the quality of their interpretations.

Production data diagnostics

There are four areas of investigation in production data diagnostics:

1. Outlier removal
2. Liquid loading in the wellbore
3. Single phase flow in the reservoir
4. Consistency (correlation) between rate and pressure

Outlier removal

The first step in production data diagnostics is the removal of outliers. Apart from adding extraneous noise to what is often an already confusing mass of data, these outliers can cause incorrect interpretation if they are not removed. For example, often outliers show a unit slope on typecurves. This unit slope may be easily misdiagnosed as reservoir depletion. It should *not* be used as an indication of original-gas-in-place or of boundary-dominated flow. A simple solution is to simply identify and remove the outliers from the analysis.

Liquid loading in the wellbore

In this step, the analyst should investigate if there is any issue with liquids loading up in the well, or if there is any unstable flow in the well. If liquid loading exists, and the sandface flowing pressure is being calculated from wellhead measurements, it is very easy to get the wrong answer, because multiphase flow calculations do not account for “stagnant” liquid columns in the wellbore. The following points should be considered in this step:

- If the pressure data is measured at the mid-point of perforations (MPP), then liquid loading or any other wellbore issues will not affect production data analysis. However, any correction from the gauge depth to the MPP can be a source of error (sometimes significant, depending on the distance between them).
- If the sandface pressure is being calculated from wellhead measurements, and the “quiet side” is being used (for example, the well is flowing through tubing and the pressure source is the annulus), the calculation down to end-of-tubing (EOT) is often very good. However, from the EOT to the MPP, there often exists a “stagnant” liquid column, which must be accounted for by estimating a “flowing” gradient (estimated at 0.2 - 0.3 psi/ft or 4-7 kPa/m for water).
- If the sandface pressure is being calculated from wellhead measurements, and the “flowing side” is being used, multiphase flow calculations must be used, and their accuracy (unless calibrated to similar flowing conditions) is questionable.

The following plots can be used to identify liquid loading. (Some of the plots can be used to identify productivity issues as well as liquid loading.)

- **Gas rate and sandface pressure versus time** — If there is a high degree of scatter in production rates and pressures, then it indicates unstable flow in the well, like slugging, and/or unstable operating conditions.
- **Difference between casing and tubing pressure versus time** — The tubing and casing pressure profiles should track each other if there is no problem in the wellbore. The plot shows that if the difference between casing pressure and tubing pressure is changing (diverging tubing and casing pressures with time), then there is possibility of liquid loading.
- **Water-gas-ratio or condensate-gas-ratio versus time** — A fluctuation or rapid decrease in the water-gas ratio and condensate-gas ratio is an indication of unstable flow in the well. Fluctuation is an indication of slug flow and a rapid decrease is an indication of liquid loading. If slug flow is indicated, yet no water rate is reported, then the quality of calculated sandface pressures may be questionable, even if the wellhead pressures are of high quality.

The water-gas ratio versus time plot has another practical importance. A rapid increase in the water-gas ratio could indicate possible productivity issues related to water (for example, water coning), as gas relative permeability decreases significantly at high water-gas ratios.

- **log (q) versus log (t)** — This plot has diagnostic value in cases where the gas rate is decreasing abnormally as a result of liquid loading or any other productivity issues. The log scale tends to compress the late-time data and accentuate the declining rate trend in the late-time data. This plot may also accentuate the fluctuation in gas rate, which can be useful to identify slug flow.

All the above indicators of wellbore liquid problems must be viewed together, as they are often complementary effects, but some of them may be more evident than others.

Single-phase flow in the reservoir

A plot of the water-gas ratio versus time is used in this step. If the water-gas ratio is high, the assumption of single-phase flow in the reservoir may not be acceptable. A threshold value for the water-gas ratio should be defined (suggested value of 100 bbl / MMscf), and the portion of the data with a water-gas ratio higher than the threshold value should not be used for analysis using typecurves and analytical models, as these analysis methods are developed assuming single-phase flow inside the reservoir.

Consistency (correlation) between rate and pressure

After removing the outliers, and the data which indicates liquid loading and productivity issues in the wellbore, and/or multiphase flow inside the reservoir, the analyst should look for consistency between pressure and rate data. If the rate and pressure data are inconsistent with each other, they should be identified and should *not* be used to interpret reservoir effects (permeability, skin or gas-in-place). The series of *Diagnostic Plots* described in the following section are recommended for use in identifying or accentuating any such inconsistency.

The concept of a diagnostic plot implies that a certain feature or behavior emerges from a given data profile. More specifically, diagnostic plots should highlight that the data is “bad” by indicating that a certain expected feature does not exist, or that the displayed profile deviates significantly from expectations. When this occurs, the apparent signal is potentially misleading and the wrong reservoir interpretation would be extracted, if the analyst proceeds. As explained by Anderson et al. 2006, a diagnostic plot for production data should:

- Highlight that there is something wrong with the production data.
- Identify the causes of misbehavior, if any exist.
- Show if the flow rate and flowing pressure are correlated or not.

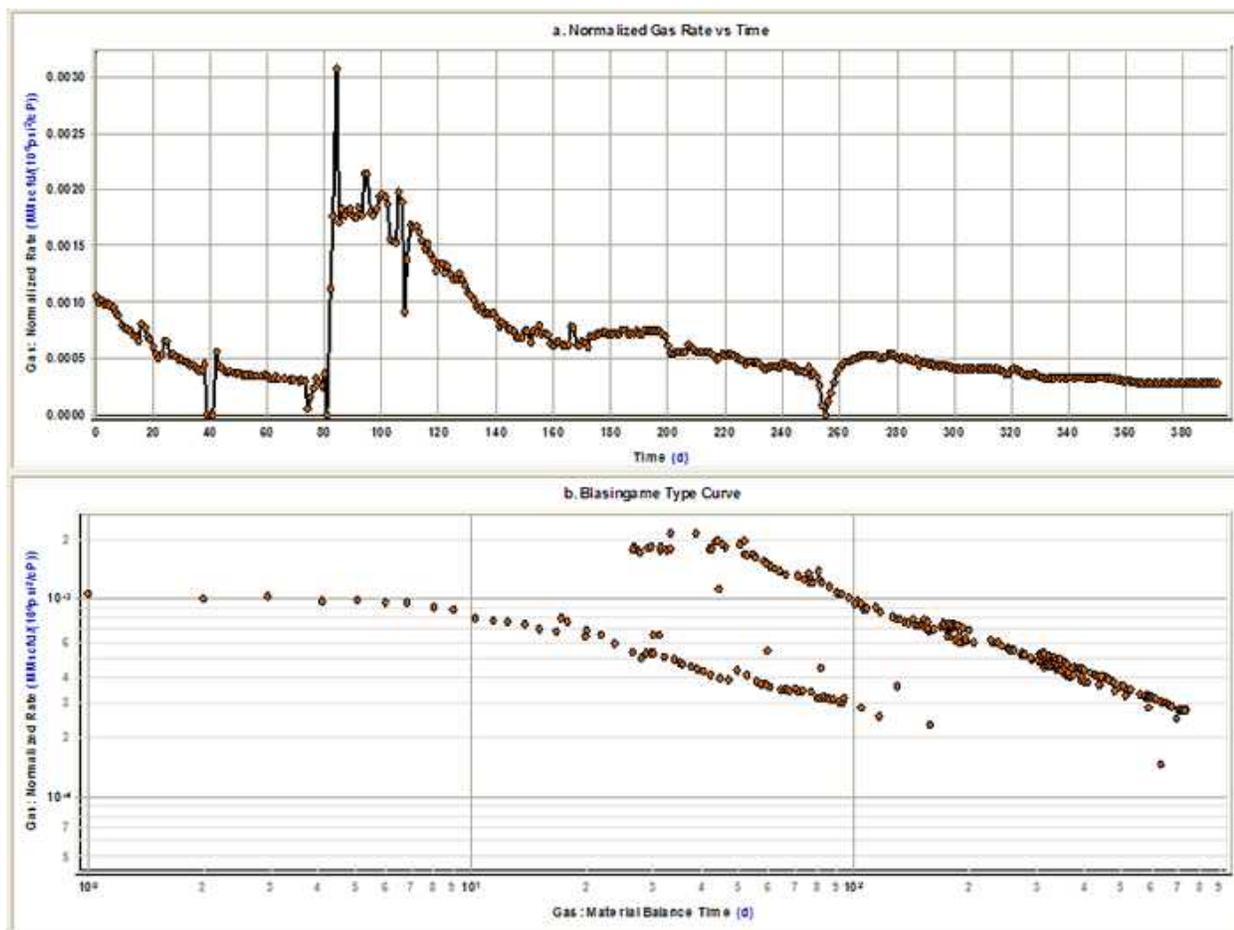
The diagnostic plots for identifying inconsistent production data are described below:

- **Gas rate and sandface pressure versus time** — Visually check for a negative correlation between rate and pressure data. This means that if the flow rate suddenly increases (or decreases), then the flowing pressure should decrease (or increase) correspondingly. If that does not happen, the rate and pressure data are inconsistent with each other, which may be because the rate is wrong, or the pressure is wrong, or the completion has changed (for example, refrac, tubing change).
- If the rate changes by an order of magnitude, it is better to use $\log(q)$ instead of q .
- **Normalized rate versus time** — This is a plot of $q / \Delta p_p$ versus time. In the absence of step changes in rate and pressure, theory indicates that $q / \Delta p_p$ must decrease continuously with time. Therefore, an increasing trend in $q / \Delta p_p$ with time indicates that non-reservoir effects are present. Note that if there are different stems in the $q / \Delta p_p$ versus time plot and $q / \Delta p_p$ is decreasing with time in each stem, (see Figure 1a), the analyst should not conclude that the rate and pressure data are inconsistent, as these different stems can be caused by step changes in rate and/or pressure. However, it forces the analyst to ask the question: Is there any inconsistency between rate and pressure data?
- **Normalized pressure versus time**—This is a plot of $\Delta p_p / q$ versus time. The trend of the plot is the reverse of the $q / \Delta p_p$ versus time plot. However, the signature and diagnostic value tends to be the same. In general, whenever a plot of $q / \Delta p_p$ is used, pretty much the same information could have been obtained by plotting $\Delta p_p / q$ instead. The choice of one or the other is a personal preference.
- **Percentage drawdown versus time** — This plot shows $[(\Delta p / p_i) * 100]$ versus time, and indicates the degree of drawdown. Knowing the degree of drawdown can be an important issue in production data diagnostics because theory indicates that the pressure variable to be used for analysis should be $D_p (= p_i - p_{wf})$. If D_p / p_i is close to unity, then we are dealing with a well with high drawdown, and in this case, the effect of p_i overshadows that of p_{wf} , and makes the rate insensitive to variations in the flowing pressure. In other words, any discrepancies in flowing pressure will not have much of an effect on rate. For example, if there is a step change in flowing pressure, this step change may not be reflected in the rate (given normal data scatter). In the case of high drawdown, even if the flow rate and pressure are *not* correlated, the diagnostic plots which depend on D_p may not indicate that there is a problem.
- The fact that high drawdown yields pressure-insensitive rates is a diagnostic onto itself. This is very useful when public data is analyzed, as often, all or part of the pressure data is missing from the production file. If

we know that the well is producing under high drawdown conditions, then the rate is insensitive to flowing pressure and any discrepancies in flowing pressure do not really matter.

- **Blasingame typecurve** — This is a log-log plot of normalized rate (q / Dp_p) versus material balance time, (that is, G_p / q), where G_p is the cumulative production of gas and q is the gas rate. Theoretically, normalized rate must decrease continuously with material balance time. Therefore, an increasing trend indicates that non-reservoir effects are present. If there are step pressure or rate changes, they will cause a sudden deviation from the decreasing trend, but the general trend will be resumed if the data is consistent. However, if there are different stems in this plot, it is an indication of inconsistency between rate and pressure data (see Figure 1b).
- **NPI typecurve** — This is a log-log plot of normalized pressure (Dp_p / q) versus material balance time (G_p / q). This plot is the inverse of the Blasingame plot. Theoretically, the normalized pressure must increase continuously with material balance time. Therefore, a decreasing trend indicates that non-reservoir effects are present. If there are different stems in this plot, it is an indication of inconsistency between rate and pressure data.
- **FMB rate** — This is based on the flowing material balance (FMB) concept. It is a Cartesian plot of normalized rate (q / Dp_p) versus normalized cumulative (G_p / Dp_p). Theoretically, the normalized rate must decrease continuously with normalized cumulative. Therefore, an increasing trend indicates non-reservoir effects. If there are different stems in this plot, it is an indication of inconsistency between rate and pressure data.
- **FMB pressure** — This is the inverse of the FMB rate plot. It is a Cartesian plot of normalized pressure (Dp_p / q) versus material balance time (G_p / q) and should be increasing continuously. Therefore, a decreasing trend indicates that non-reservoir effects are present. If there are different stems in this plot, it is an indication of inconsistency between rate and pressure data.
- **Blasingame-Cartesian** — This is a Cartesian plot of normalized rate (q / Dp_p) versus material balance time (G_p / q). Theoretically, normalized rate must decrease continuously with material balance time. Therefore, an increasing trend in normalized rate with material balance time indicates that non-reservoir effects are present. If there are different stems in this plot, it is an indication of inconsistency between rate and pressure data.

Figure 1: Example of step change in rates or pressures in normalized rate versus time and Blasingame typecurve plots



All of the above plots do not always show the same inconsistencies. Depending on the data quality, the variations in operating conditions, rate fluctuations, source of measurements, and the degree of drawdown, some plots highlight an inconsistency, while others may not. We therefore recommend that all these plots be drawn and inspected, and if any one of them shows an inconsistency, the data should be examined in detail to understand the cause and severity of the problem. The case studies below demonstrate how plots can be used.

Case studies

To demonstrate the performance of the proposed diagnostic plots in evaluating the quality of production data, we use relevant field examples to illustrate specific issues. In each example, all or some of the useful plots are presented. All of the diagnostics plots were constructed from raw data, with no interpretation required, and most often, using sandface flowing pressure calculated from wellhead measurements. It is worth noting that not all of the proposed plots provide diagnostic insight in every case. This is why the analyst should always look at a combination of the

plots, in the hope that one or more of them indicates an anomaly that is worth investigating, or highlights an inconsistency in the data.

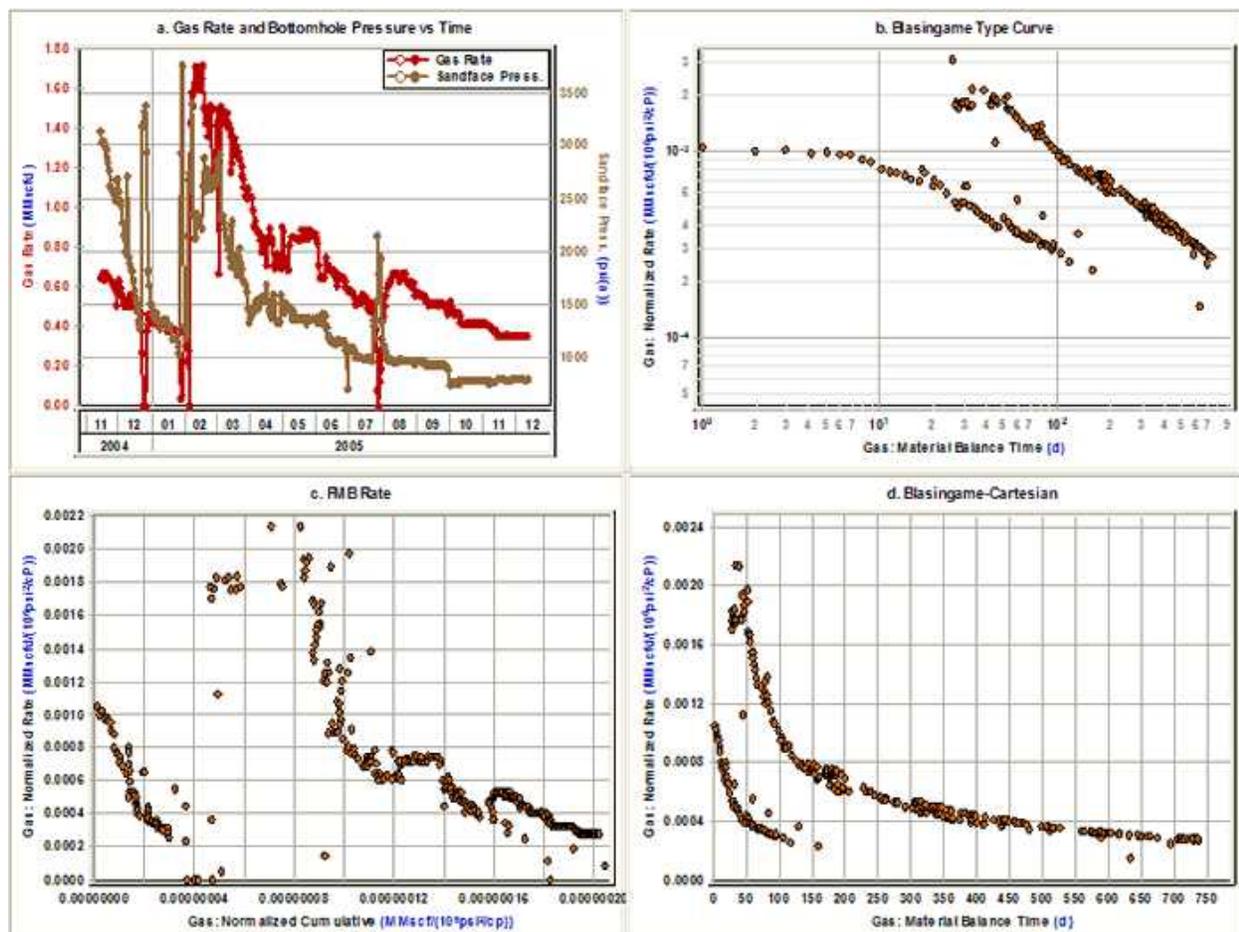
Note: The term "sandface" is now used instead of "bottomhole".

Case 1

This case represents a well that was stimulated after three months of production. Some of the useful diagnostic plots are shown in Figure 2.

Figure 2a shows the rate and sandface flowing pressure versus time plot. From this plot, we can see that the well was shut in for two days in February 2005 and after that the rate and pressure increases rapidly. Looking at Figure 2b, it is evident from this plot that there are two stems in the typecurve. One stem is for data before February 2005 and one is for data after February 2005. It can also be seen that the productivity of the well ($q / \Delta p_p$) has increased after February 2005. This is due to the fact that the well was fractured on February 5, 2005. Figure 2c is a plot of $q / \Delta p_p$ versus $G_p / \Delta p_p$. Extrapolation of this plot to the x-axis gives an estimate of the original-gas-in-place. It is obvious from this plot that the frac not only improved the productivity of the well, but also added more reserves as shown by the increase from the original-gas-in-place to the ultimate-gas-in-place. Only data collected after February 5, 2005 should be used in any interpretation, as the reservoir model has changed.

Figure 2: Case 1 diagnostic plots



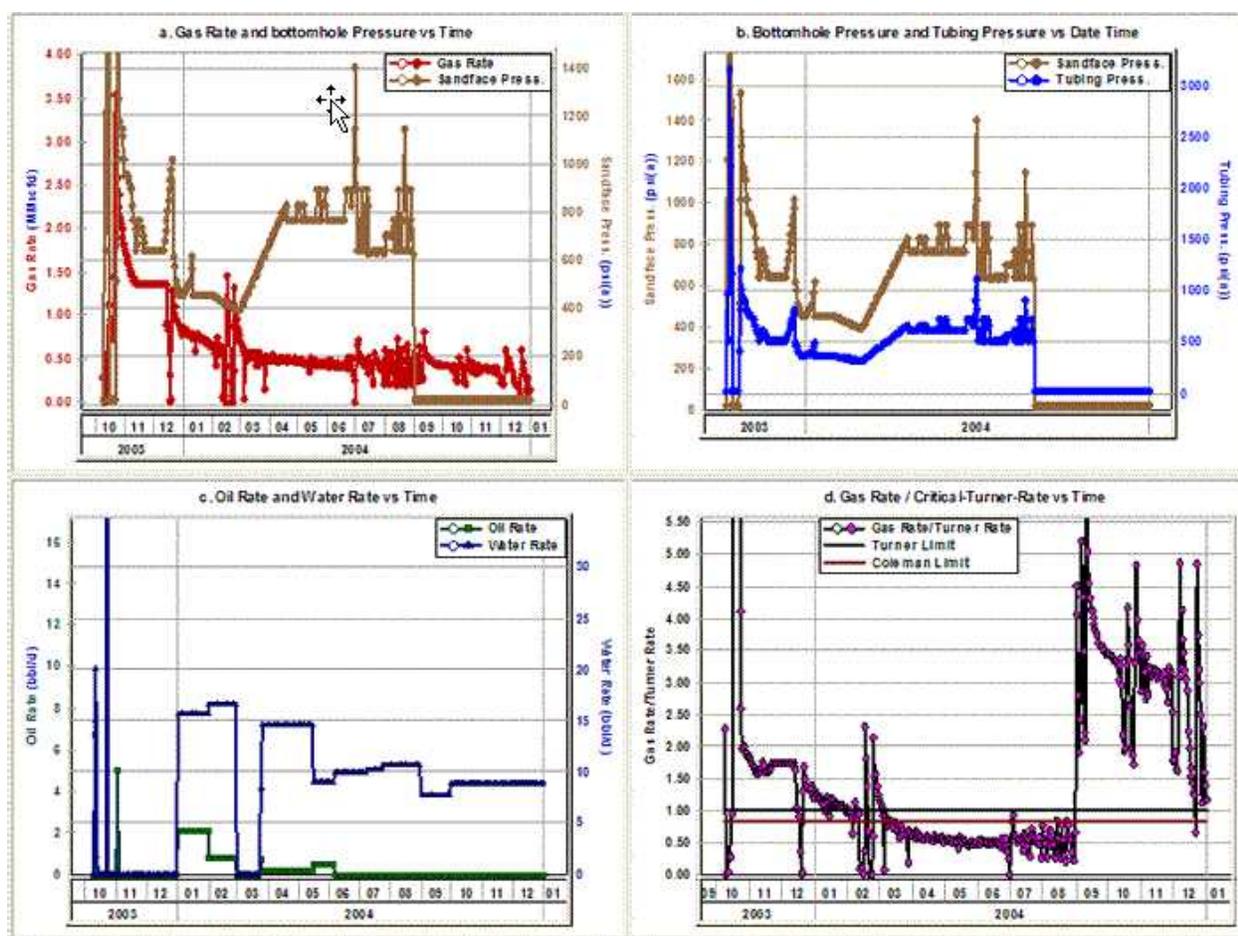
Case 2

Figure 3a shows the gas rate and sandface flowing pressure versus time. It can be seen from this plot that the sandface flowing pressure is almost a straight line from the beginning of March 2004 until the middle of April 2004. The same thing can be seen for tubing pressure in Figure 3b. In practice, it is not likely that the tubing pressure profile would be a straight line for a period of time. If the tubing pressure has a straight line profile for a period of time, it implies that it was not measured frequently and the data has been interpolated and not measured. This will be reflected in the reliability of the calculated sandface flowing pressure data.

This well also produced water and oil. Figure 3c shows the oil rate and water rate versus time plot. Looking at this plot, it is obvious that the oil rate and water rate have flat profiles with large step changes. This again means that oil rate and water rate were not measured frequently and this will have a significant effect on the quality of the calculated sandface flowing pressure data, because multiphase flow calculations depend directly on gas-liquid ratios.

Figure 3d shows the gas rate / critical-Turner-rate ratio versus time plot. This plot shows that the well may be loaded by liquid from the beginning of March 2004 to the end of August 2004. This is consistent with fluctuations in the gas rate during this period. This plot also shows that the gas rate is higher than the critical-Turner rate from the beginning of September 2004 to the end. The tubing pressure during this period is constant and equal to 13.0 psi (apparently a gauge pressure of 0, converted to absolute). This is not a valid pressure. Therefore, the calculated flowing sandface pressure and the critical-Turner-rate calculations after September 2004 are not valid, and should be discounted in any interpretation.

Figure 3: Case 2 diagnostic plots

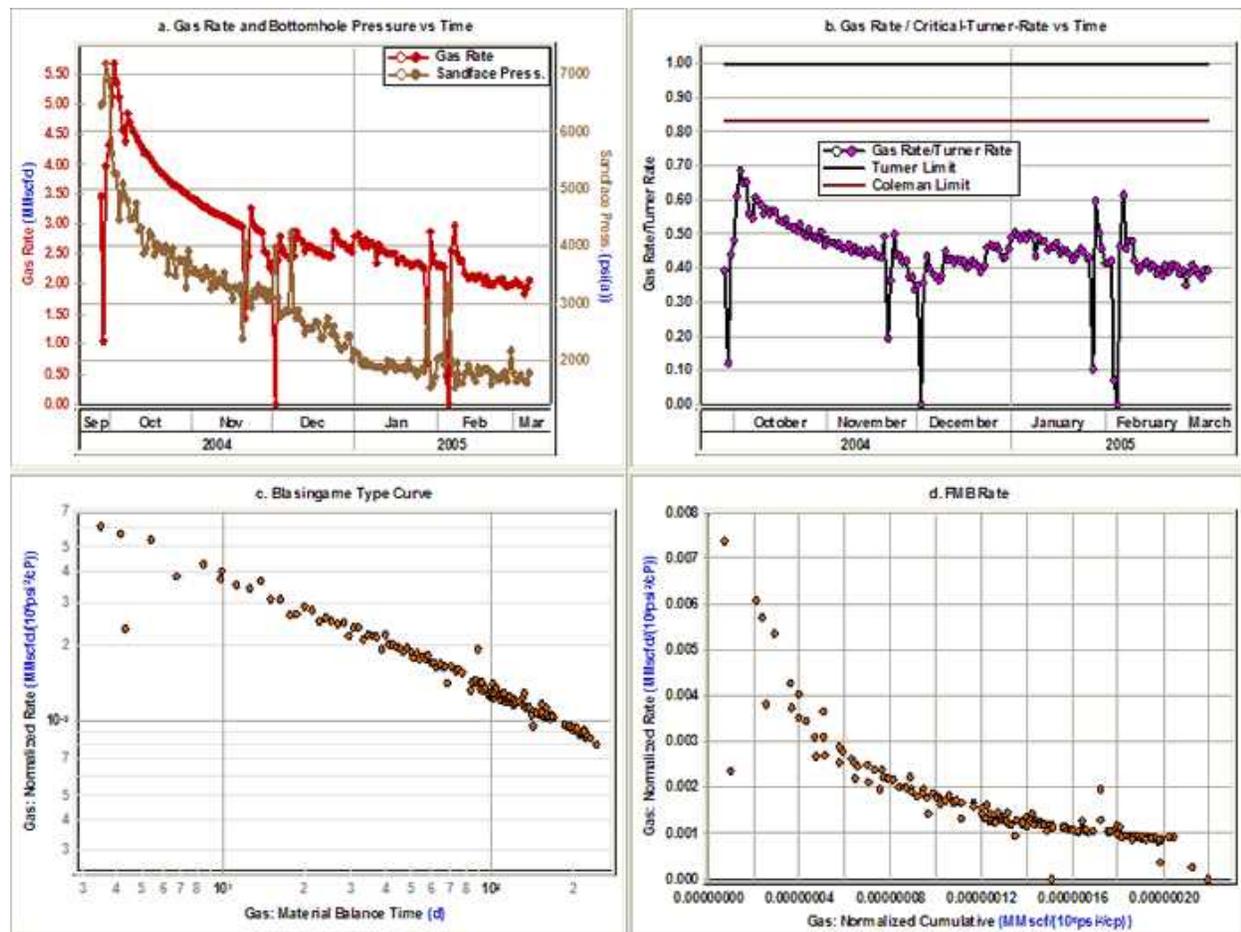


Case 3

Figure 4a shows the gas rate and calculated sandface flowing pressure versus time. Looking at this plot, everything seems to be normal. Figure 4b shows the ratio of gas-rate / critical-Turner-rate versus time plot. According to this plot, the rate is less than both the Coleman and Turner

critical lift rates, which indicates that the well is probably loaded with liquids. However, there is no liquid production reported at all. The gas rate is higher than 2 MMscfd and there is no indication of slugging or liquid loading in the trend of the gas rate and flowing pressure. The Blasingame typecurve and FMB rate plots are well behaved. The problem in this case is that the specified tubing ID was wrong. This directly affects the values for critical-Turner rate, but has little effect on the calculated flowing sandface pressure, as it only affects the friction component of the pressure loss inside the wellbore, which is very small compared to hydrostatic pressure loss. Therefore, the flowing sandface pressures calculated using the wrong tubing ID, in this case of dry gas production, can still be used for analysis.

Figure 4: Case 3 diagnostic plots



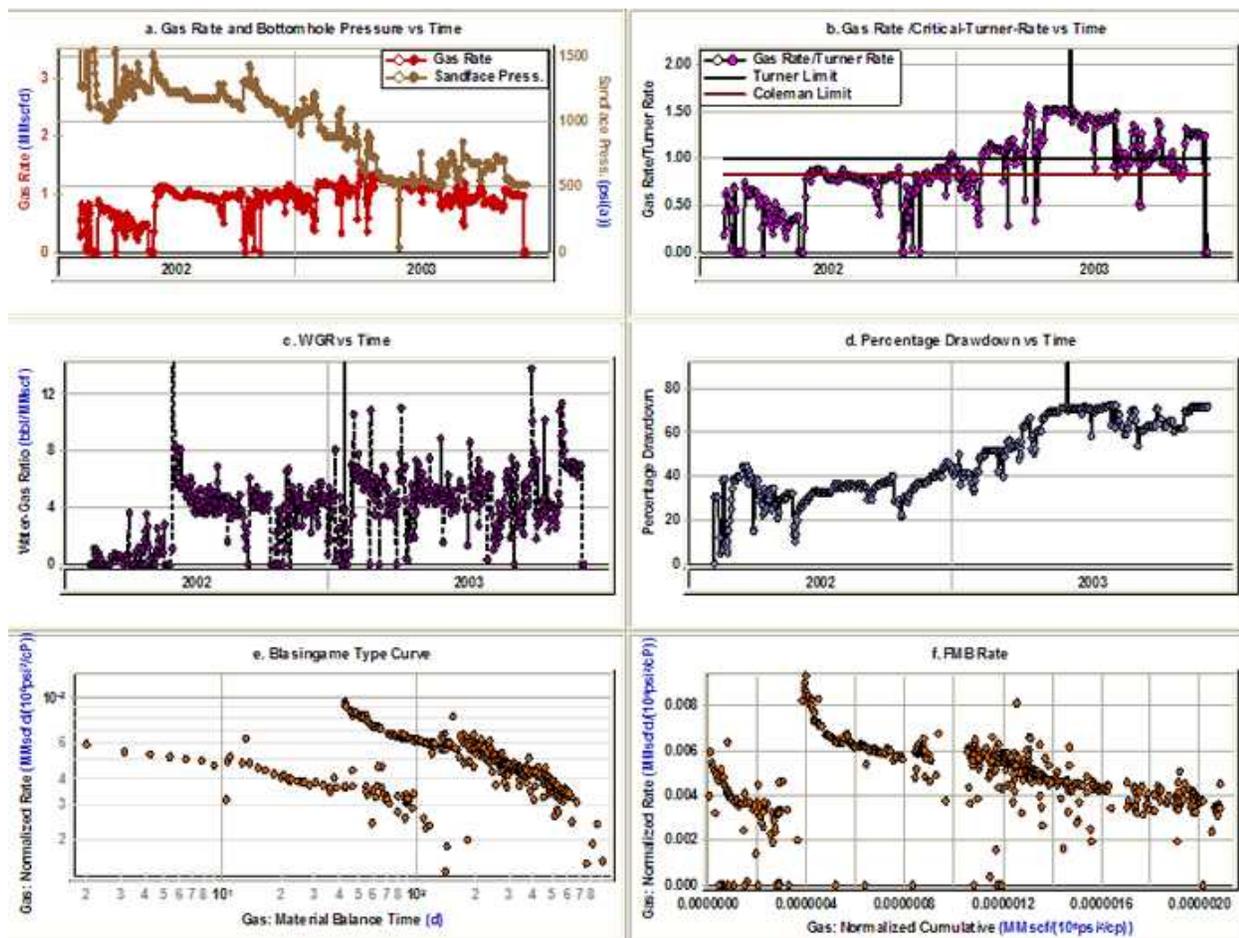
Case 4

Figure 5a shows the gas rate and sandface flowing pressure versus time for a high permeability gas well. Figure 5b shows the ratio of gas-rate / critical-Turner-rate versus time plot for this well.

This plot shows that the gas rate is lower than the Turner rate before July 1, 2002. Looking at the gas rate and sandface flowing pressure versus time and water-gas ratio versus time plot shows that something happened on July 1, 2002. There is a step change in the rate and the flowing pressure, and a significant increase in the water-gas ratio (Figure 5c). This behavior is consistent with a tubing change-out (where tubing is replaced with a smaller diameter to lift liquids and eliminate the liquid lifting problem). This tubing change was not documented for this well.

Looking at the Blasingame typecurve and FMB rate plots also shows there is some inconsistency between rate and flowing pressure data, as there are two stems on these plots. One of the stems is for data before July 1, 2002 and the other stem is for the data after July 1, 2002. The main reason for having two stems is because of having “stagnant” liquid column in the wellbore before July 1, 2002. This liquid column was not considered when calculating the sandface pressure during this period, and therefore, the calculated sandface pressure data for this part of data is wrong. Only data collected after July 1, 2002 should be used in any interpretation, as the calculated flowing sandface pressure data is more reliable.

Figure 5: Case 4 diagnostic plots

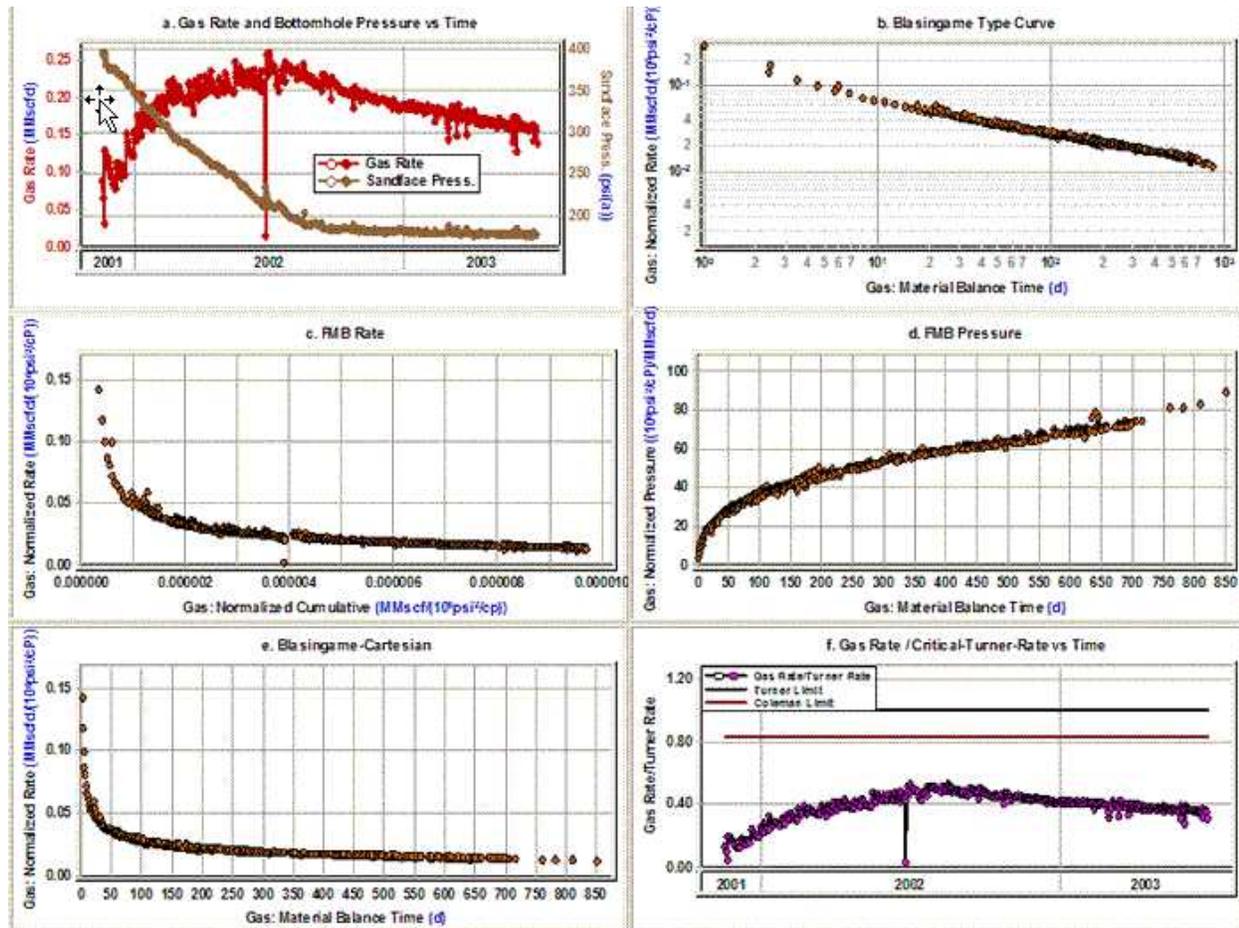


Case 5

Figure 6a shows the gas rate and sandface flowing pressure versus time for a hydraulically fractured well. Figure 6 (that is, plots b-to-e) shows some of the proposed diagnostic plots. These plots do not show any inconsistency between rate and pressure.

Figure 6f shows the ratio of gas-rate / critical-Turner-rate versus time plot. According to this plot, the gas rate is less than the critical liquid lift rate throughout the whole producing life. In addition, Figure 6a shows fluctuation in gas rate and this indicates that there is slug flow. Although there is indication of slug flow in Figure 6a and liquid loading in Figure 6f, no water production has been reported. Therefore, sandface pressure calculations from wellhead pressure are likely incorrect.

Figure 6: Case 5 diagnostic plots



Case 6

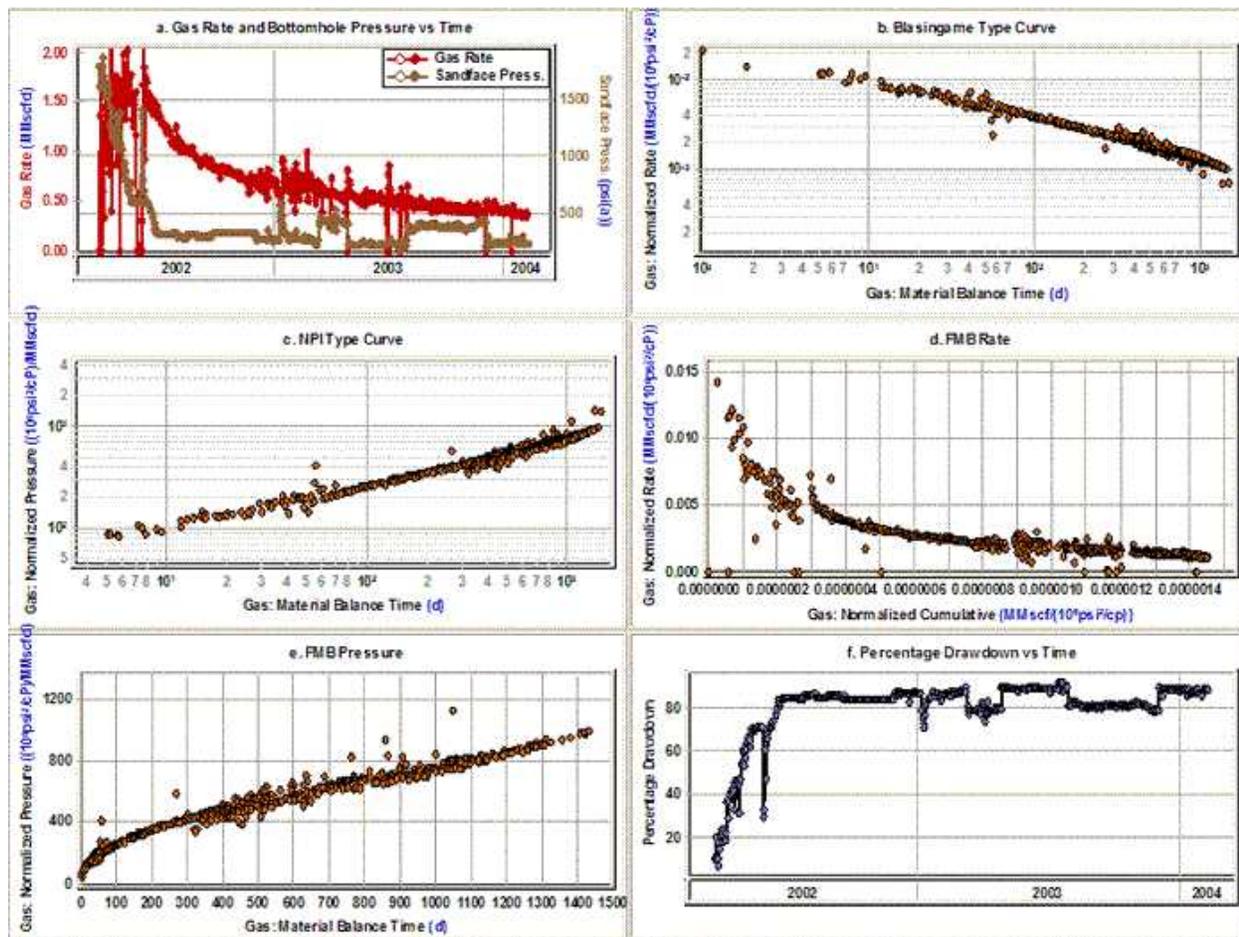
Figure 7a shows the gas rate and calculated sandface flowing pressure versus time for a horizontal gas well. Visual inspection of Figure 7a indicates some inconsistencies between pressure and rate. It can be seen from this plot that:

- The pressure profile is flat from July 2002 to December 2002.
- There is a step change in pressure at the end of July 2003, but this step change is not reflected in the gas- rate data.

Some of the proposed diagnostic plots are shown in Figures 7 b-f. There is no evidence of these inconsistencies in Figures 7 b-e. Figure 7f shows the plot of percentage drawdown $[(\Delta p / p_i) * 100]$ versus time for this well. According to this plot, except for the first two months of production, the well is producing under almost 85% drawdown. This means that we are dealing with a high drawdown well, and that the rate is insensitive to flowing pressure and that any discrepancies in

flowing pressure have very little effect on interpretation. This is the reason why no inconsistency was observed in Figures 7b-e.

Figure 7: Case 6 diagnostic plots



Case 7

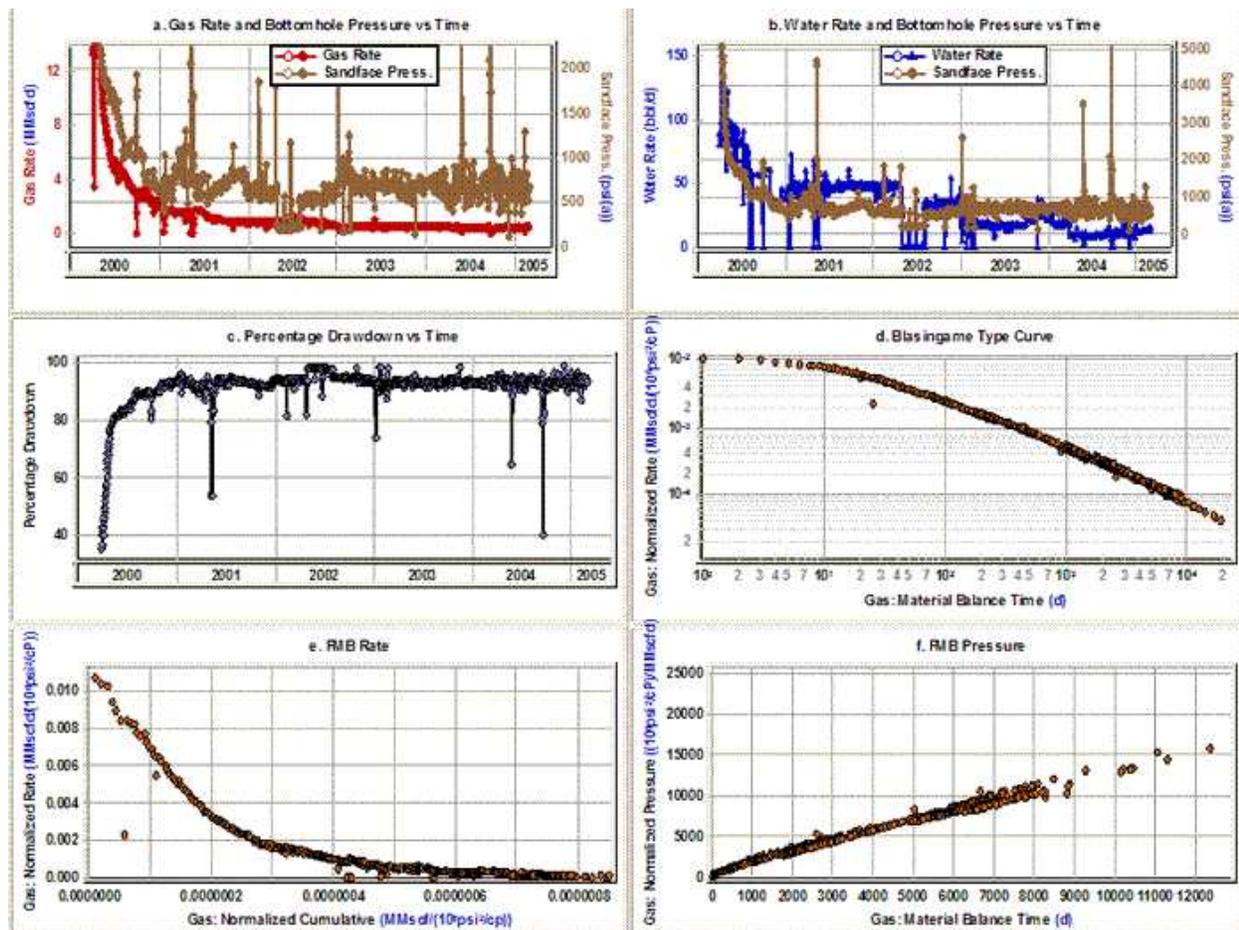
This is a high-permeability gas well. This well is producing through tubing and only tubing pressure data is available. Figure 8a-f shows some of the diagnostic plots for this well. Figure 8a shows the gas rate and sandface flowing pressure versus time for this well. Everything seems normal except for the data between the beginning of May 2002 until the end of July 2002:

- The sandface flowing pressure suddenly decreases in early May 2002, but this step change is not reflected in gas-rate data.
- The gas rate suddenly decreases in late June 2002, but this step change is not reflected in the sandface flowing pressure data.

To find out why the rate and pressure are not consistent in this period, we reviewed at the water-rate data. The plot of water rate and sandface flowing pressure is shown in Figure 8b. This plot shows that the well was producing almost 50 bbl/d of water from the beginning of 2001 until the beginning of May 2002, and no water rate was reported from the beginning of May 2002 until the end of July 2002. The water rate affects both hydrostatic and friction pressure losses in the wellbore, and has a huge effect on the magnitude of the calculated sandface pressures. This can explain the inconsistency between rate and sandface pressure from the beginning of May 2002 until the end of July 2002, as the water rate is not reported. If the casing pressure had been available, the problem would have been less severe because the sandface pressure could have been calculated using casing pressure data instead. This would not have been affected by an incorrect liquid rate, as it involves a hydrostatic head calculation of a dry gas column to the end-of-tubing.

Figure 8c shows the plot of percentage drawdown versus time for this well. According to this plot, except for the first two months of production, the well is producing under almost 95% drawdown. This means that the diagnostic plots which use Δp or Δp_p may not show any inconsistency between rate and flowing pressure data even when they are not consistent. Looking at Figures 8d-f does not indicate any sign of inconsistency, which was expected because of high drawdown.

Figure 8: Case 7 diagnostic plots



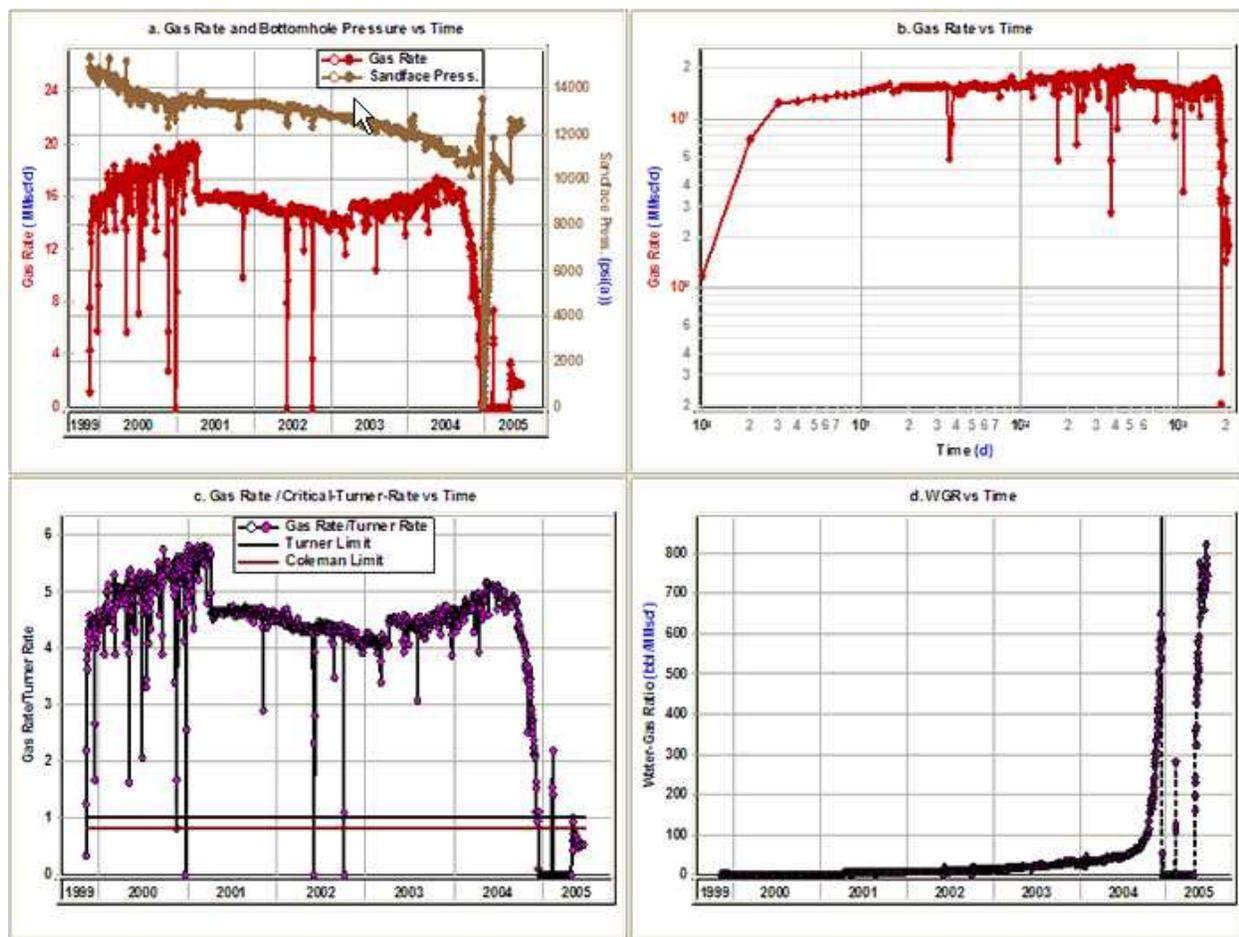
Case 8

This is a high-permeability gas well. In this example, we do not emphasize the consistency between pressure and rate data. We just want to point out the value of diagnostic plots for indicating reservoir productivity issues. The gas rate and flowing sandface pressure versus time is plotted in Figure 9a. It can be seen from this figure that there are two step changes in rate, which are not reflected in pressure data. This plot also shows that the rate declines rapidly from September 2004. Figure 9b shows log q versus log t for this well. As can be seen, this log-log plot accentuates the declining trend in rate, as it compresses the late-time data. Liquid loading can sometimes cause this abnormal decrease in gas rate.

To investigate the possibility of liquid loading, the ratio of gas-rate / critical-Turner-rate is plotted versus time and presented in Figure 9c. It can be seen from this figure that when the gas rate started to decline, the gas rate was much higher than the critical liquid lift rate. The rapid decline in rate therefore indicates a decrease in reservoir productivity and not liquid loading. Figure 9d shows the water-gas ratio versus time for this well. This plot shows a rapid increase in the water-

gas ratio at the same time that rate declines rapidly. Therefore, the rapid decline in gas rate was because of water reaching the well inside the reservoir and not liquid loading, and in fact, it is a reservoir problem not a wellbore problem. The fact that this well is producing this much water could mean that we are dealing with an active water-drive reservoir, or that a secondary gas cap is pushing water ahead of it to the well. The well was shut in for six months, but after that, the same problem occurred very quickly (that is, a high water-gas ratio).

Figure 9: Case 8 diagnostic plots

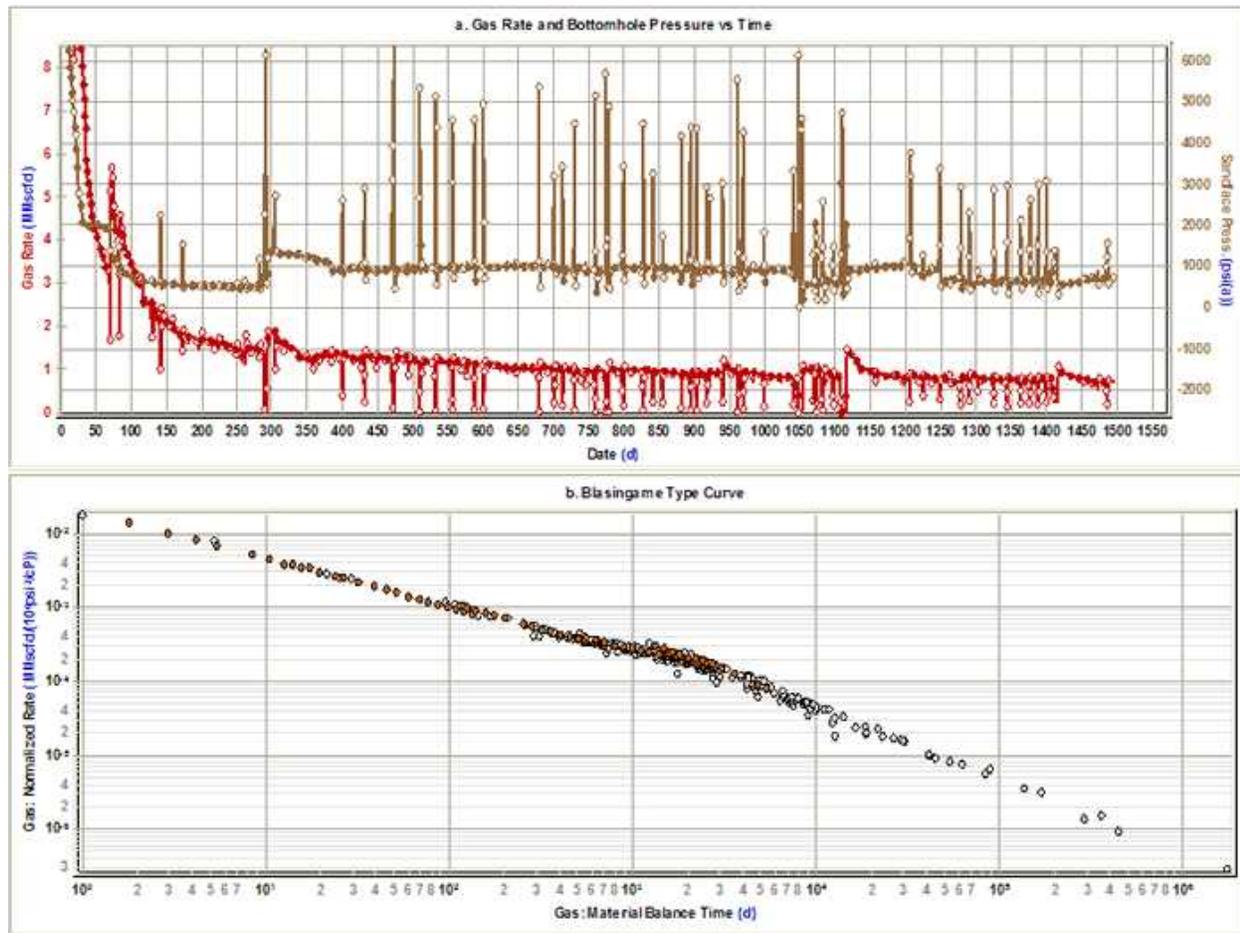


Case 9

As mentioned earlier, the first step in production data diagnostics is the removal of outliers to eliminate any incorrect interpretation caused by these outliers. It was also mentioned that often outliers show a unit slope on typecurves. In this example, we present a dataset that shows this problem. Figure 10a shows the gas rate and sandface flowing pressure versus time. The outliers are shown by hollow points, so they can be distinguished from the rest of the data. Figure 10b

shows the Blasingame typecurve plot for this case. The outliers are also shown by hollow points in this plot. It can be seen from this plot that the unit slope on this typecurve is caused by outliers, not depletion. Therefore, this unit slope should not be used as an indication of original-gas-in-place or boundary-dominated flow.

Figure 10: Case 9 diagnostic plots



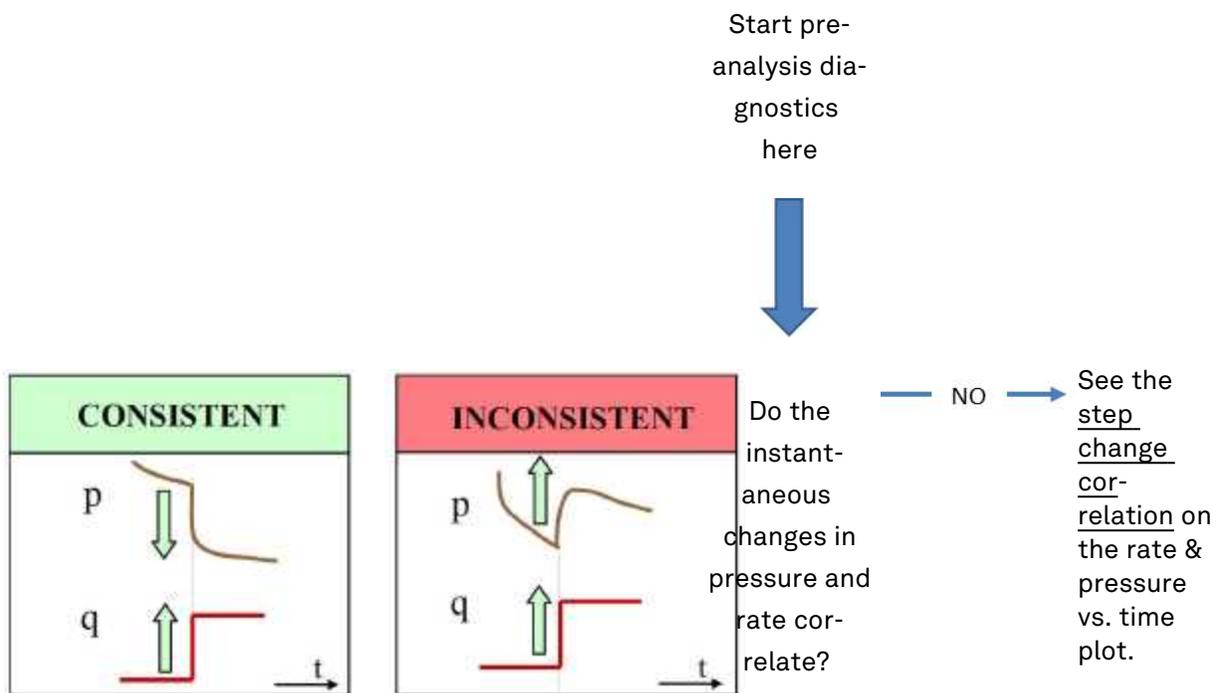
Data diagnostics flowchart

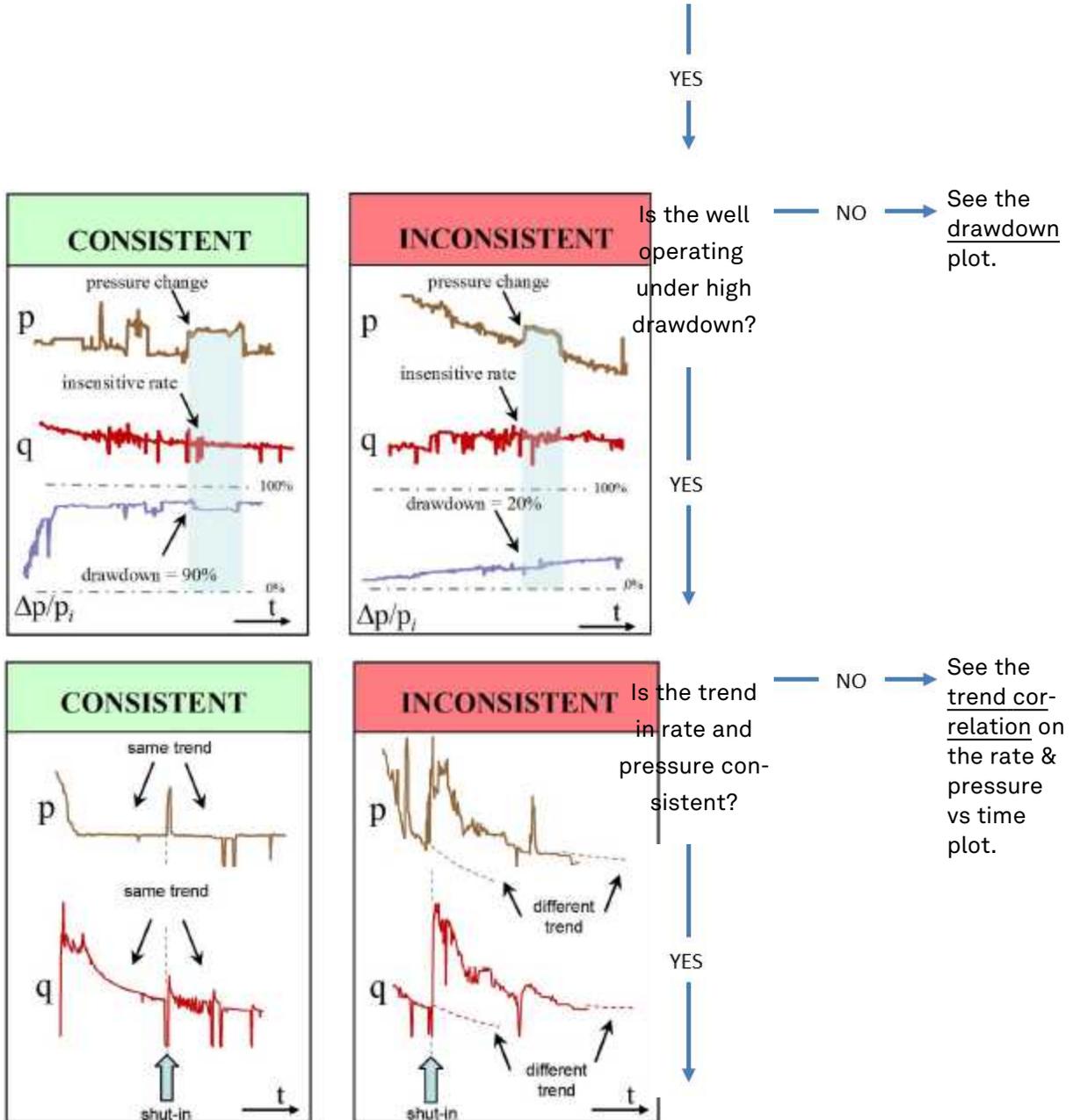
Common causes for data inconsistencies are as follows:

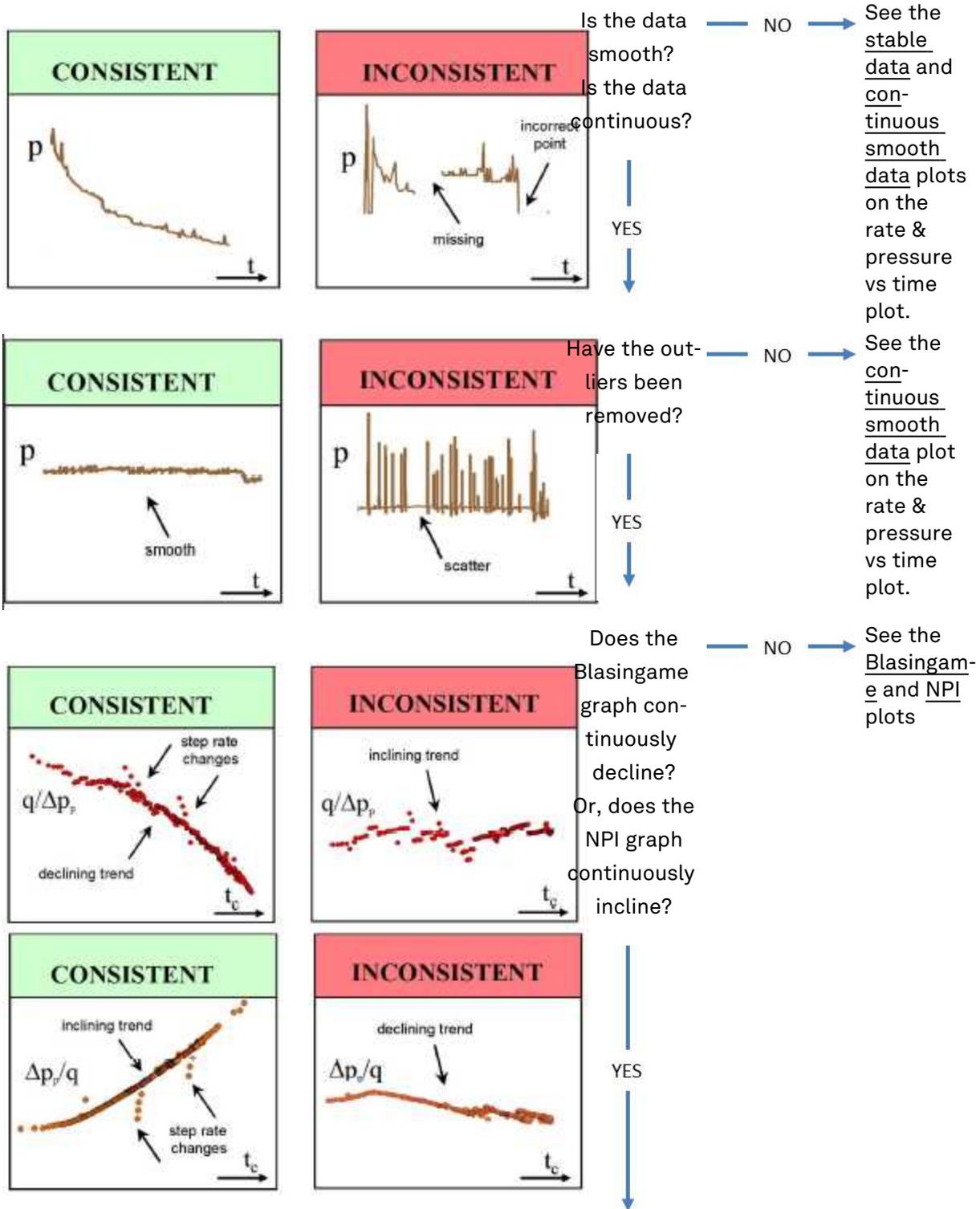
- Recompletion, reperf, refrac
- Fracture cleanup
- Wellbore cleanup

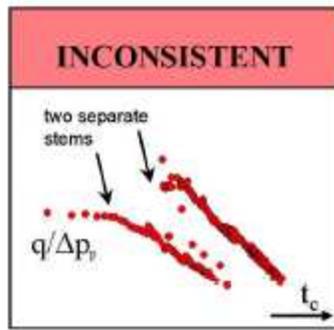
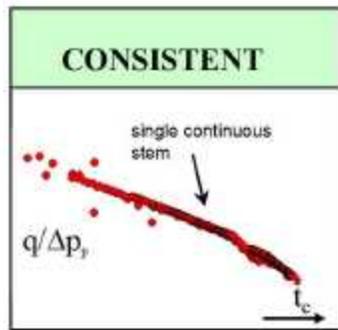
- Liquid loading
- Slugging
- Tubing change-out
- Changing flow path
- Under-reported work-overs
- Incorrect pressure source and flow path
- Pressure or rate averaging
- Out of sync pressure and rate time-tracks
- Missing flowing pressures or rates
- Incorrect initial pressure
- Misreported water production
- Significant increase in water gas ratio (WGR)

Use the flowchart below to evaluate the quality of your data:



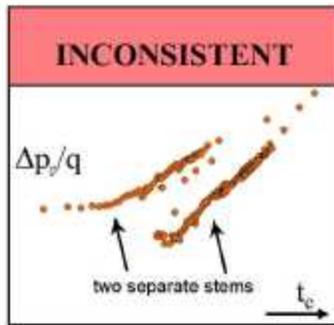
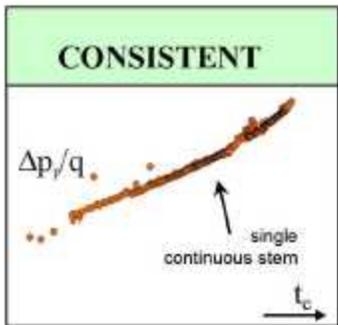




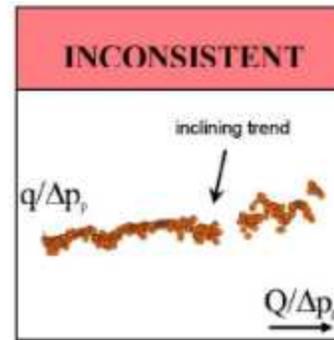
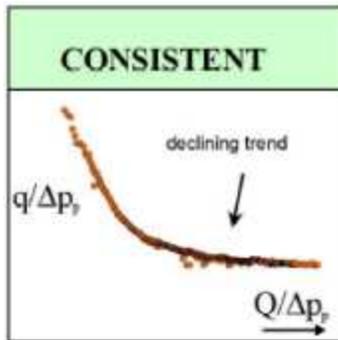


Do the Blasingame or NPI plots contain a single continuous stem?

NO → See the Blasingame and NPI plots

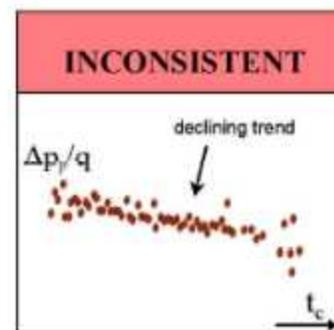
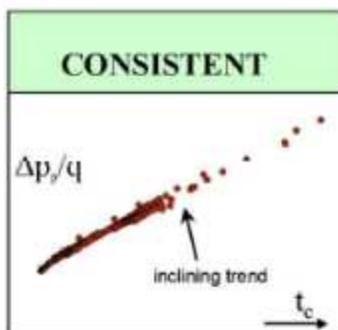


YES

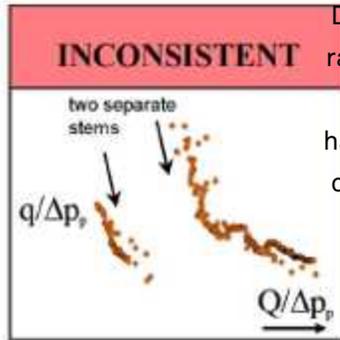
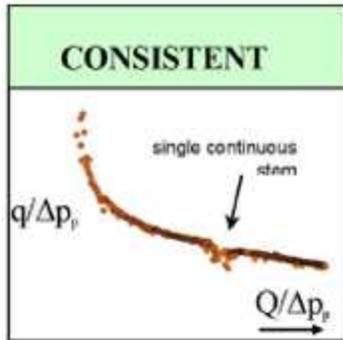


Does the FMB rate plot trend decline?
Or, does the FMB pressure plot trend incline?

NO → See the FMB rate and FMB pressure plots



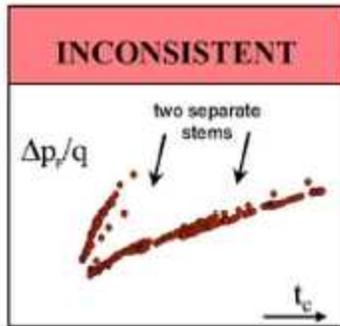
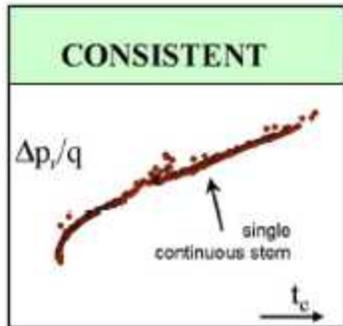
YES



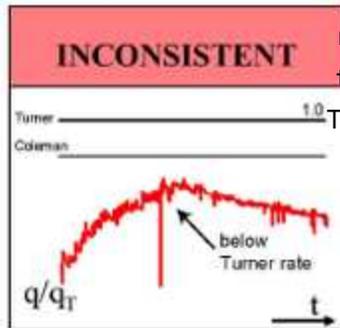
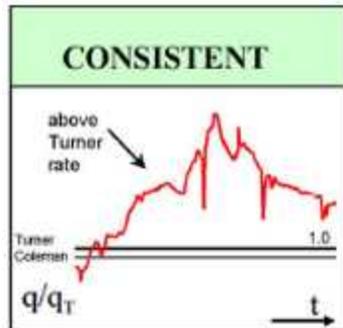
Do the FMB rate or pressure plots have a single continuous stem?

NO

See the FMB rate and FMB pressure plots



YES

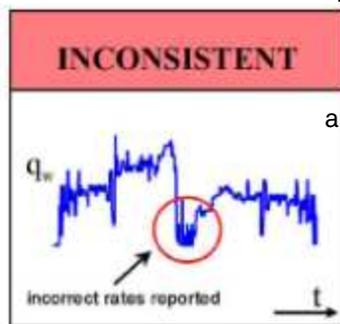
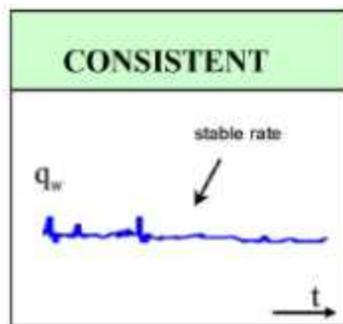


Is the gas rate above the critical Turner rate?

NO

See the Turner rate plot

YES

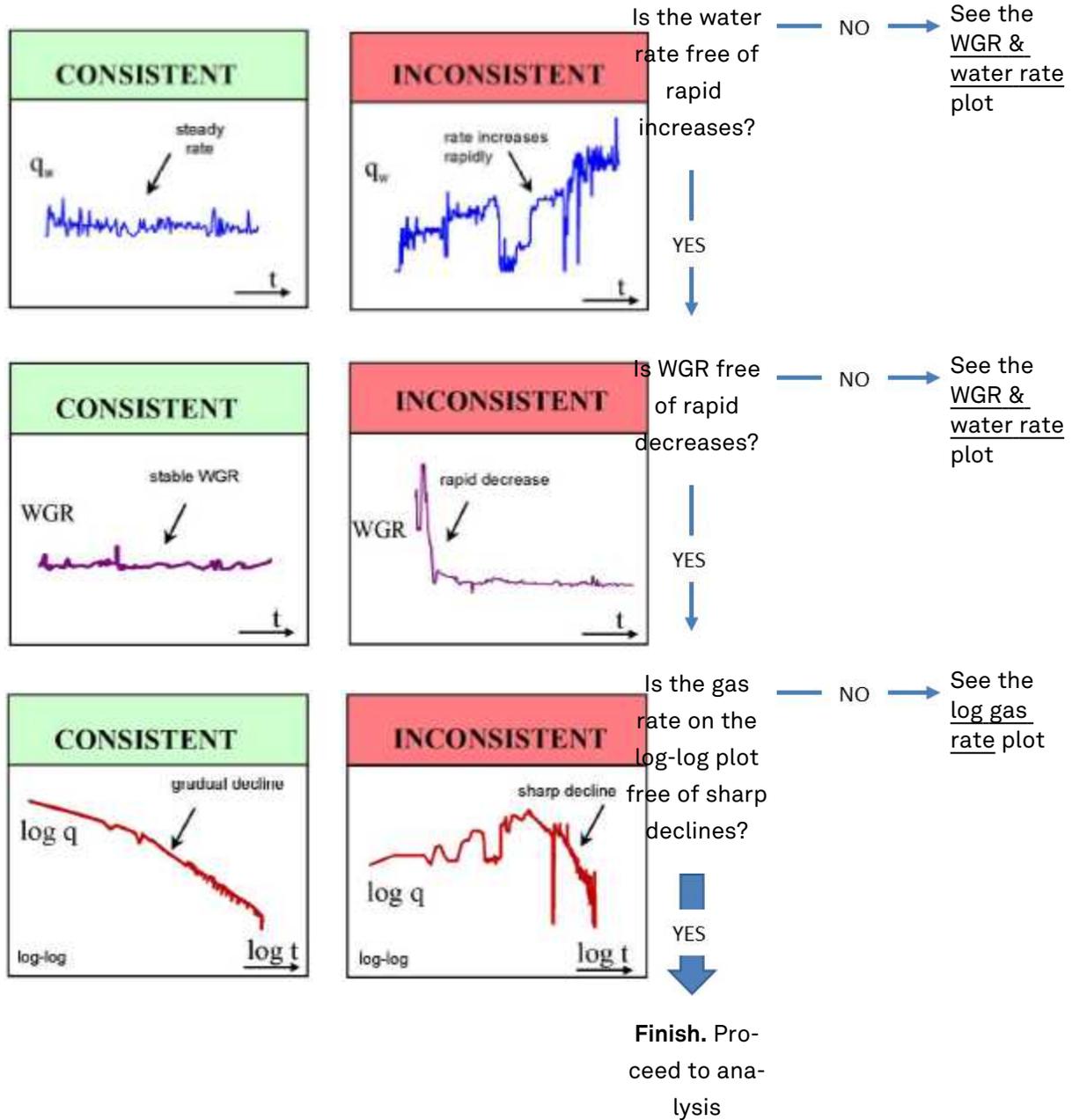


Is the water rate reported? Does it appear to be correct?

NO

See the WGR & water rate plot

YES



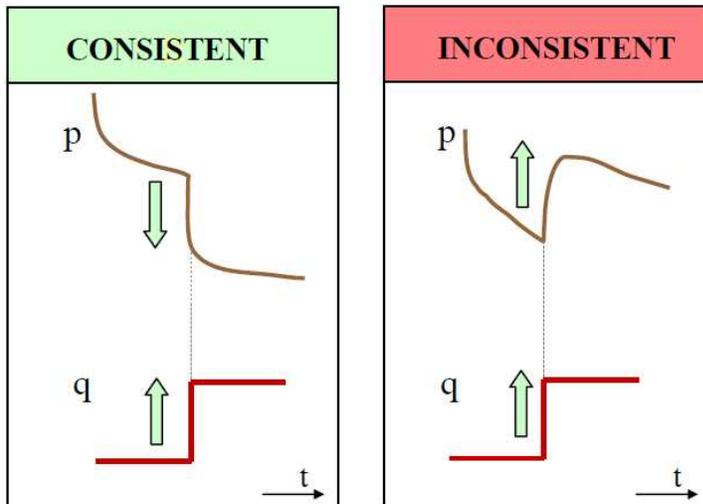
Rate & pressure vs. time (Cartesian) plot

[Return to the data diagnostics flowchart](#)

Examine the rate & pressure vs. time (Cartesian) plot to answer the following questions:

- Do step changes in pressure and rate correlate with each other?
- Is the general trend in the rate reflected in the pressure, and vice versa?
- Is the production rate and pressure data stable?
- Is the rate and pressure data smooth, continuous, and free of scatter?

Do step changes in pressure and rate correlate with each other?

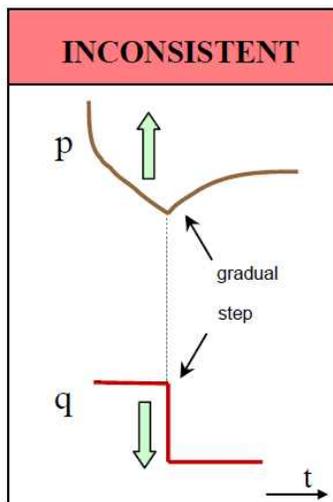
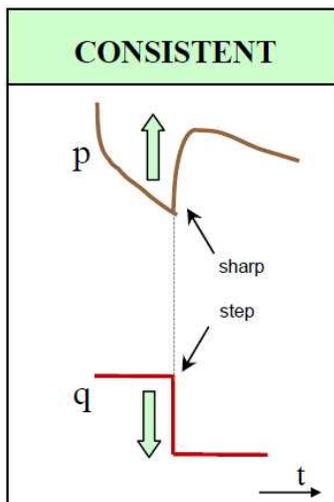


- A sharp *increase* in rate should correspond to a sharp *decrease* in pressure, and vice versa.
- The response to a step change should be immediate and not gradual.

Reasons for inconsistencies:

Incorrect pressure

- The pressure may have been measured on the other side of the choke / valve.
- A change in liquid holdup in the wellbore.
- At high drawdown, the rate becomes insensitive to pressure changes. For additional information, see the percentage draw-down plot. If changes in pressure are not reflected in the rate data, this may not be a cause for concern.
- Pressures may be measured every minute, but reported daily. An average daily rate is meaningful, but an average daily pressure is not.



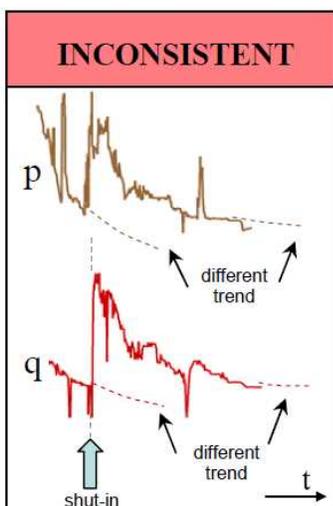
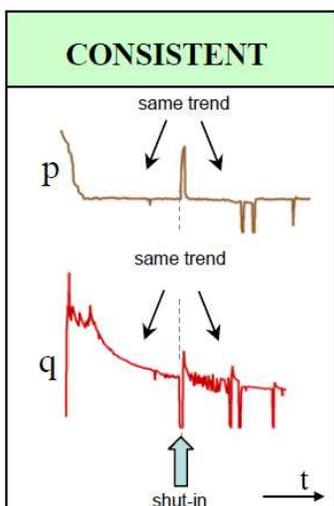
Incorrect rate

- The rate may be averaged from group metering.
- The rate may be a daily or monthly average.
- Unreported liquid production from a gas well.

Time periods

- If the data in different time periods is inconsistent, the data in the low-flow-rate region is more likely to be in error.

Is the general trend in the rate reflected in the pressure, and vice versa?

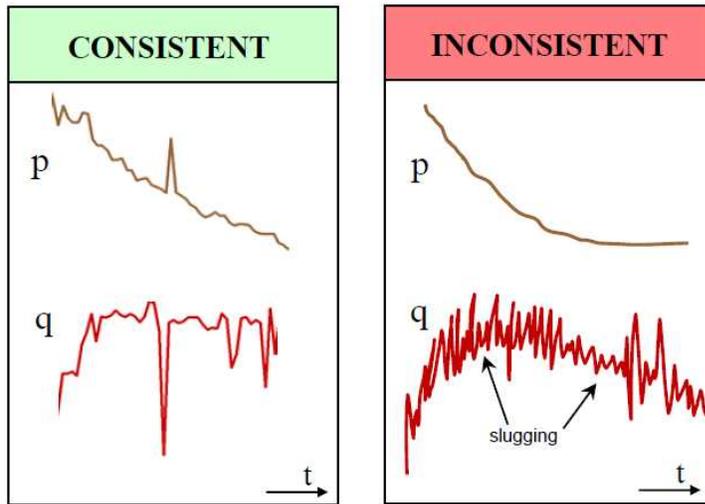


- If the rate is disrupted but comes back to the original trend, the pressure should also return to its original trend.
- If there is a change in the rate trend, the change in the pressure trend should be consistent with these bulleted items.

Reasons for inconsistencies:

- A change in operations (for example, location of pressure measurement, metering, etc.).
- Tubing change-outs, hydraulic fractures, work-overs, recompletions, etc. The Blasingame, NPI, FMB rate, and FMB pressure plots tend to be better suited for this diagnosis.

Is the production rate and pressure data stable?

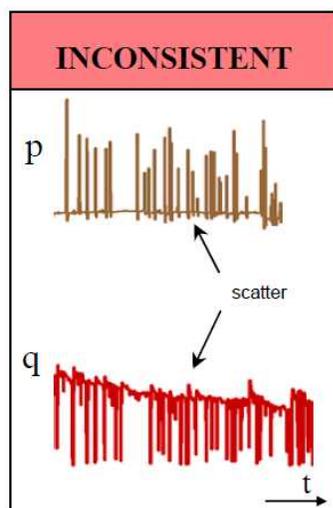
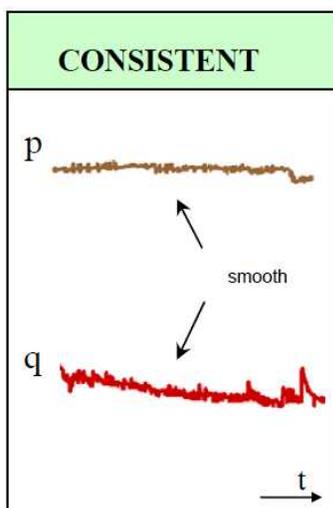


- Unstable rates indicate slugging, even though no water is reported.
- Sometimes rates are smoothed by reporting an average day rate.
- Sometimes pressure data is smoothed for supervisory control and data acquisition (SCADA) systems.
- These smoothing actions obscure fluctuations.

Reasons for inconsistencies:

- Liquid production may only be measured at the plant, and not at the well.
- Often water production is not properly reported.
- Liquid loading in the wellbore.
- The WGR & water rate plot provides further insight.
- The Turner rate plot is a valuable diagnostic tool.
- Sandface pressures can fluctuate, even though wellhead pressures are smooth. This is due to the multiphase calculations of sandface pressures.

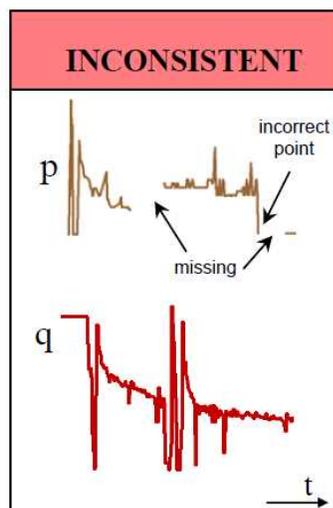
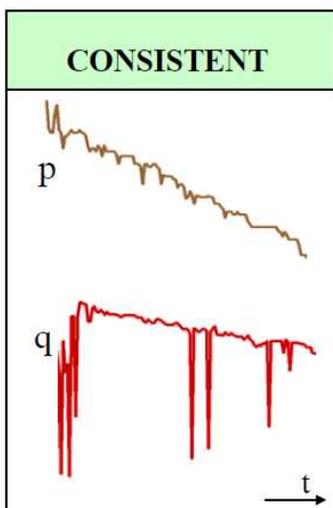
Is the rate and pressure data smooth, continuous, and free of scatter?



- Outliers can create a false unit slope (which suggests boundary-dominated flow) on type-curves that use the concept of "material balance time".
- Interpolation of missing pressures is often misleading.
- If the reported data appears too smooth, it is possible that interpolations are used, instead of measurements.

Reasons for inconsistencies:

- Pressure and rate data often contain outliers. This scatter can be removed from the production dataset using a median filter.
- Sometimes failing to exclude these outliers can result in false conclusions about the reservoir, because they tend to line up on a unit slope on a typecurve log-log plot. For additional information, see the [Blasingame](#) plot.
- These outliers can be recognized because they are sparse.
- Linear interpolation or averaging of pressures is not a true representation of reservoir characteristics.
- The rule of thumb is that if the data appears too straight, it is most likely incorrect, not measured, or interpolated.



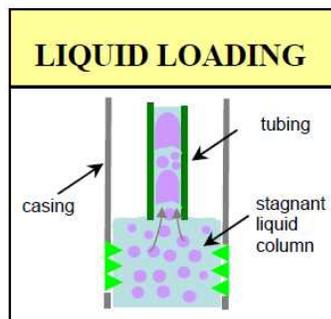
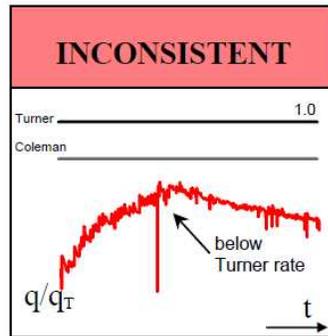
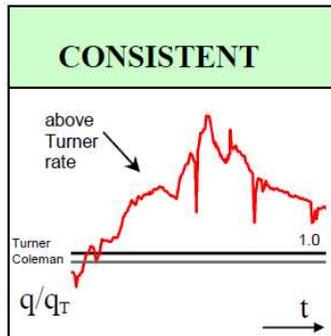
Turner rate

[Return to the data diagnostics flowchart](#)

These questions apply to the Turner rate:

- Is the gas rate above the critical Turner rate?
- Do the casing and tubing pressures track one another?

Is the gas rate above the critical Turner rate?



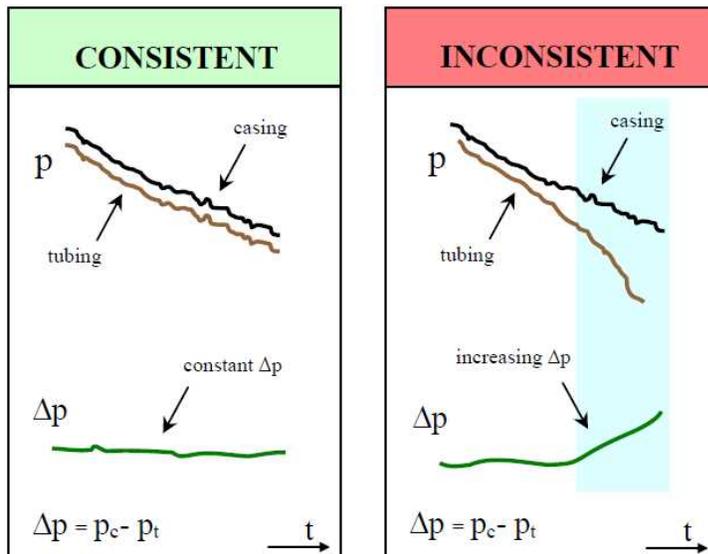
- The critical Turner rate is defined as the minimum rate required to lift liquids in the wellbore. The plot is the ratio of gas rate / critical-Turner rate (q/q_T).
- If the ratio < 1 , there is a likelihood of liquid loading.
- The critical Coleman rate is an alternative to the Turner rate. The Turner rate is approximately 20% higher than the Coleman rate, and many operators prefer the Coleman calculation to that of Turner.
- If the ratio is < 1 , calculations for sandface pressures from wellhead measurements are likely to be in error, due to not accounting for a “stagnant” liquid column. For additional information, see the WGR & water rate plot.

Reasons for inconsistencies:

- The gas rate below which liquid loading occurs depends on the diameter of the pipe and the pressure of the gas. Liquid loading occurs more often when producing through the casing.
- When liquid loading is indicated (ratio < 1), it is often accompanied by a reduced production of liquids, or a reduced liquid / gas ratio. For additional information, see the WGR & water rate plot.

- Usually following the onset of liquid loading, the tubing is replaced with a smaller diameter tubing to increase the gas rate and lift the liquids. This event may not be recorded.
- If the specified tubing ID is incorrect, the Turner rate calculation may also be incorrect. This affects the value of the critical Turner rate, but has little effect on the calculated sandface flowing pressures.

Do the casing and tubing pressures track one another?



- Tubing and casing pressures track each other when there are no problems in the wellbore (for example, liquid loading, hydrating).

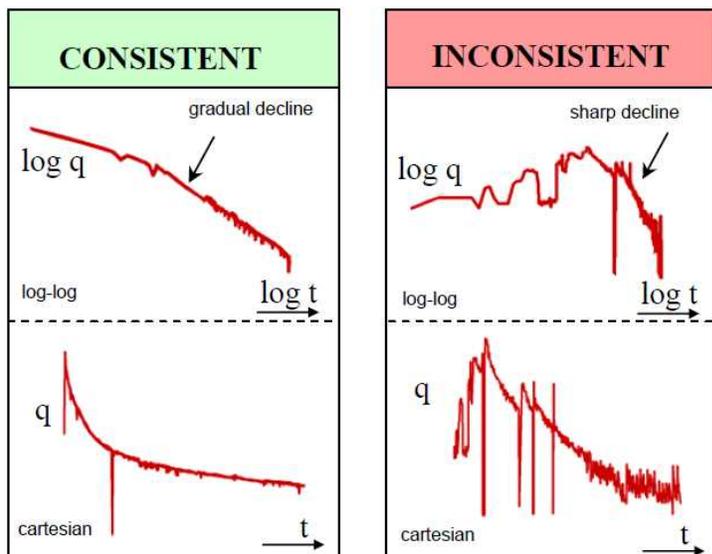
Reasons for inconsistencies:

- Diverging tubing (p_t) and casing (p_c) pressures are an indication of liquid loading or hydrating in the wellbore.
- To convert from wellhead to sandface pressure, use the quiet-side pressure (usually the casing) and assume the liquid level is at the end of tubing (EOT).
- If sandface pressure is being calculated from wellhead measurements, and the flowing side is being used, multiphase flow calculations must be used, and their accuracy is poor.

Log gas rate (log-log)

[Return to the data diagnostics flowchart](#)

Does the rate have a sharp decline when plotted on a logarithmic scale?



- The log scales tend to accentuate the problem, which may not be evident in Cartesian coordinates. The scale compression of large-time values accompanied by the scale expansion of low rates makes the problem more visible.
- A sharp decline on a log-log plot indicates a problem.

Reasons for inconsistencies:

- An abnormal decrease in the gas rate can indicate liquid loading.
- Often accompanied by the production of liquids.
- For additional information, see the WGR & water rate plot.

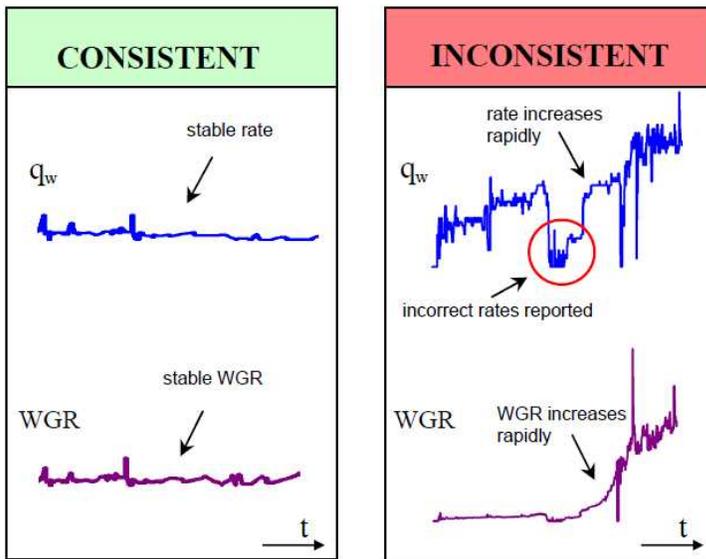
WGR & water rate

[Return to the data diagnostics flowchart](#)

These questions apply to the water gas rate (WGR) and water rate:

- Are the water rate and WGR stable and relatively constant?
- Is the flow in the reservoir effectively single phase?
- Is there a rapid decrease in the WGR?
- Are there significant fluctuations in the WGR?

Are the water rate and WGR stable and relatively constant?

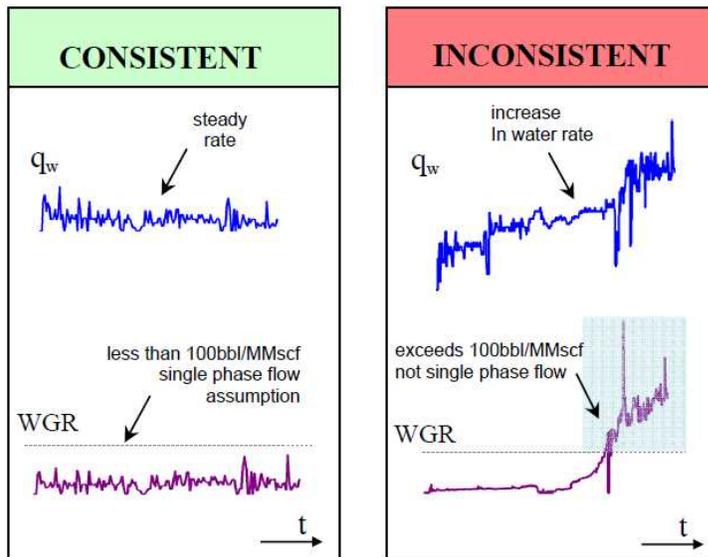


- A sudden increase in the water rate could indicate future productivity problems.
- The data following a rapid increase in WGR should be treated with caution, especially if the pressure measurements are at the wellhead.
- If pressure data is measured at the midpoint of perforations (MPP), then liquid loading or any other wellbore issues will not affect the production data analysis.

Reasons for inconsistencies:

- A sudden increase in the water rate could be due to coning, or a reservoir water influx. Either way, operating problems due to wellbore effects are likely to result in reduced productivity.
- The conversion of wellhead pressure to sandface pressure changes if water production is present (because of liquid hold-up in the wellbore).
- If the water rate is not reported, the quiet-side pressure data can be used instead, as it is not affected by an incorrect liquid rate at the end of tubing (EOT).

Is the flow in the reservoir effectively single phase?

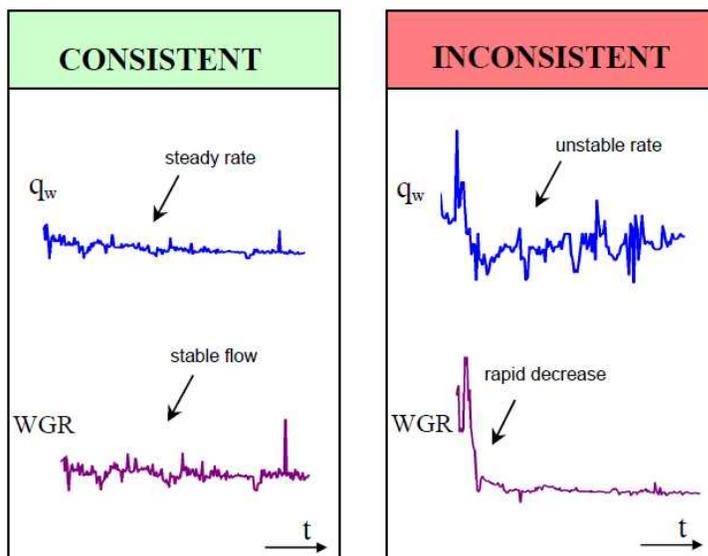


- For gas wells with low WGR, the assumption of single-phase gas flow may still be valid.
- For high WGR, the assumption of single-phase flow may not be valid. Data exceeding an approximate threshold value of 100 bbl / MMScf should be used with caution, as typecurves and analytical models assume single-phase flow.

Reasons for inconsistencies:

- Water coning results in a changing skin, which can invalidate the reservoir models in use.
- Saturation changes in the reservoir result in varying effective permeability.

Is there a rapid decrease in the WGR?



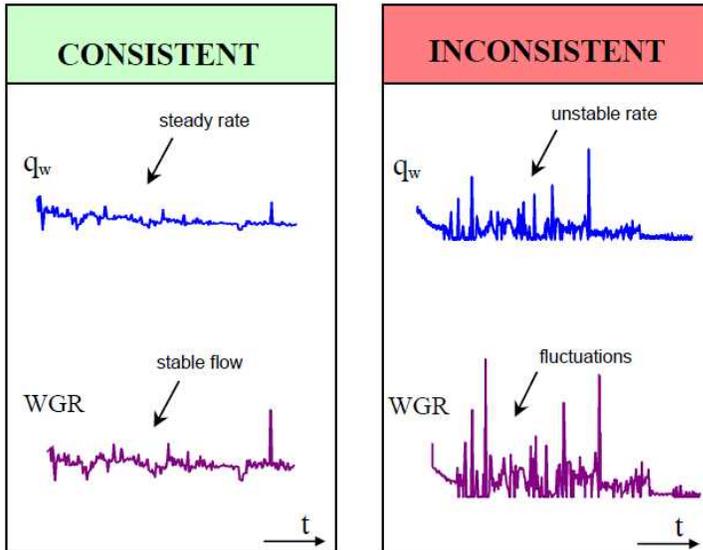
- A sudden decrease in WGR coupled with an unstable water rate could indicate liquid loading.

Reasons for Inconsistencies:

- When the gas rate decreases below a certain value known as the critical rate, the gas can no longer lift the liquids in the wellbore, and liquids start to accumulate. This is known as liquid loading and can result in a decrease in apparent water production. For more information, see the Turner rate plot.
- If sandface pressures are being calculated from wellhead measurements, an additional pres-

sure drop may need to be added to represent the “stagnant” column of liquid.

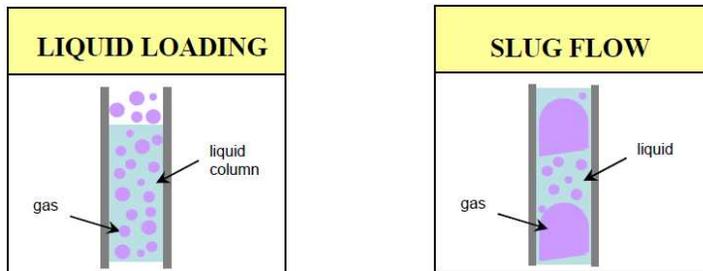
Are there significant fluctuations in the WGR?



- Fluctuations in WGR are an indication of slug flow.

Reasons for inconsistencies:

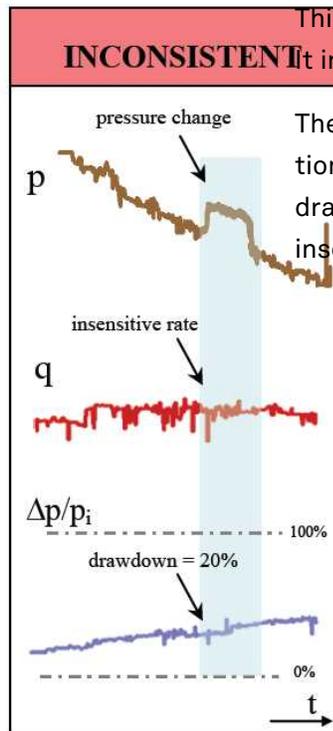
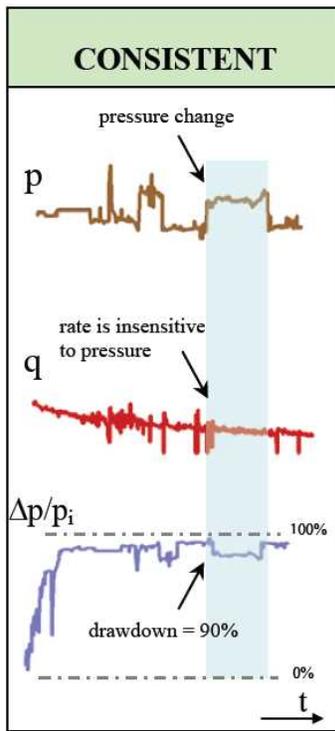
- If slug flow is indicated, yet no water rate is reported, then the quality of the calculated sand-face pressures may be questionable, even if the wellhead pressures are of good quality.



Drawdown %

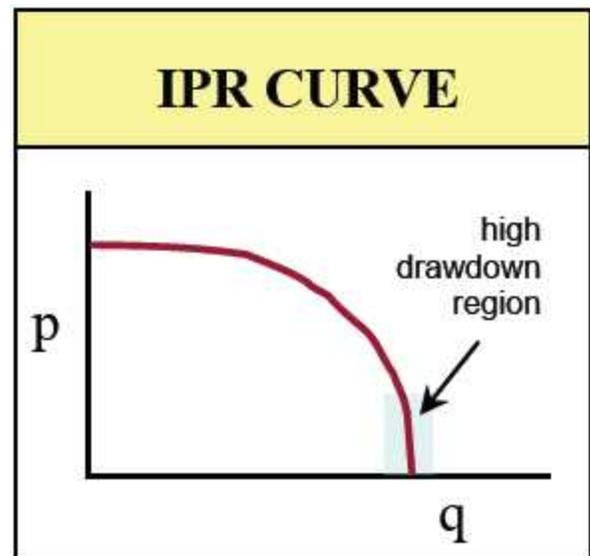
[Return to the data diagnostics flowchart](#)

Is the well producing under high drawdown conditions?



This is a plot of $\Delta p / p_i \times 100\%$ versus time. It indicates the degree of drawdown.

The shape of the inflow performance relationship (IPR) curve shows that in high drawdown situations, the rate becomes insensitive to pressure.

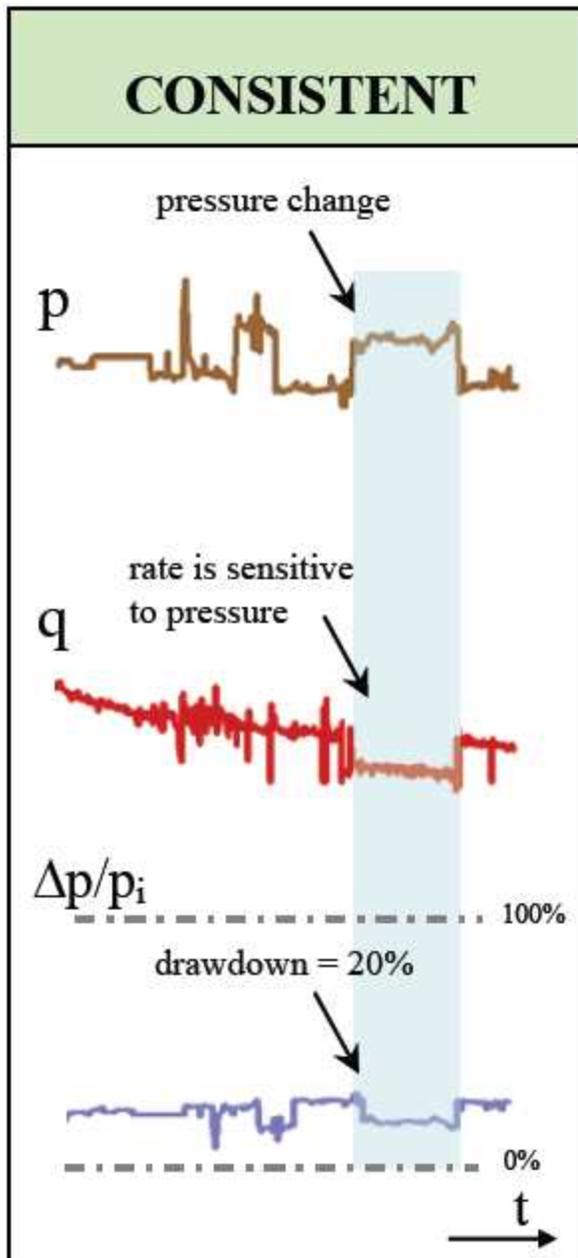


Reasons for inconsistencies:

- At low drawdown, if the flowing pressure decreases (increases), and the

rate does not increase (decrease), it means that one or the other is incorrect.

- At high drawdown, the well is operating in the low pressure region of the IPR curve. If the flowing pressure changes but the flow rate does not, it is not a cause for concern.
- At high drawdown, a lack of correlation between rate and pressure is not a cause for concern.



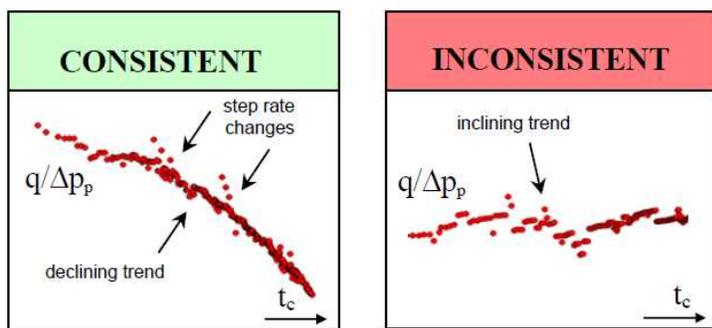
Blasingame (log-log)

[Return to the data diagnostics flowchart](#)

These questions apply to Blasingame (log-log):

- Does the normalized rate continuously decline?
- Does the Blasingame plot have a single continuous stem?
- Are outliers being misinterpreted as boundary-dominated flow?

Does the normalized rate continuously decline?

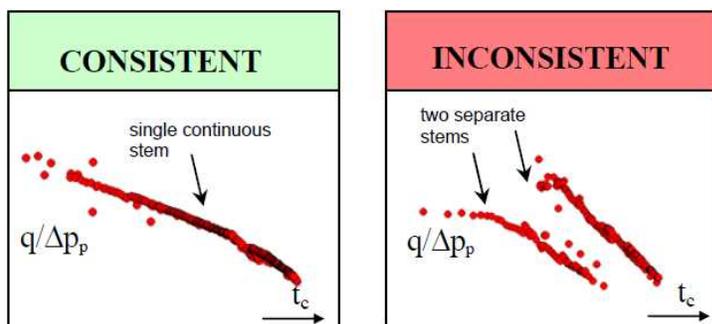


- The log-log plot of normalized rate ($q/\Delta p_p$) versus material balance time (G_p/q) should have a declining trend.
- A step change in rate causes a sudden deviation from the declining trend, but if the data is consistent, it reverts to the original declining trend.

Reasons for inconsistencies:

- An increasing trend indicates non-reservoir effects, such as near wellbore cleanup, improving skin, wellbore liquid unloading (if pressures have been calculated from wellhead data).

Does the Blasingame plot have a single continuous stem?



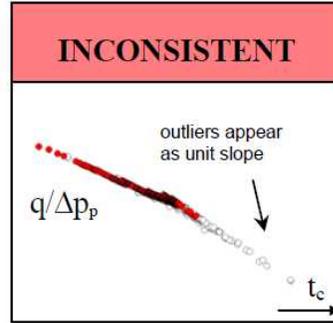
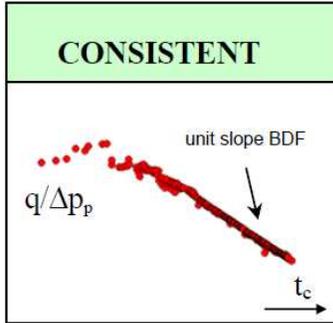
- Changes in rate or pressure are accounted for in the Blasingame plot, and should *not* cause it to develop multiple stems.
- In the case of multiple stems, the stem that represents the correct reservoir model should be used for analysis.

Reasons for inconsistencies:

- The reservoir model has changed (for example, work-over, recompletion, refrac, etc.).
- The wellhead pressures measurement location may have changed (for example, tubing,

casing, before / after valve), or there may have been a change of flow path or tubulars.

Are outliers being misinterpreted as boundary-dominated flow?



- Outliers often appear on a unit slope on the Blasingame plot. This can lead to an incorrect diagnosis of reservoir depletion or boundary-dominated flow (BDF).

Reasons for inconsistencies:

- Outliers have been included in the analyses. Apply the median filter to remove the outliers.

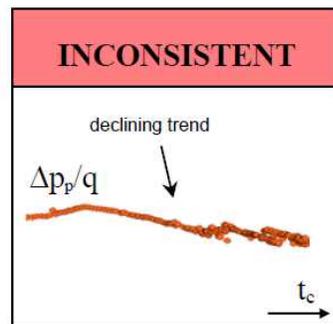
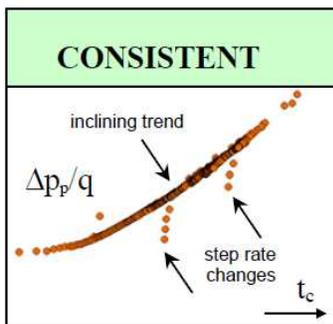
NPI (log-log)

[Return to the data diagnostics flowchart](#)

These questions apply to the normalized pressure integral (NPI) – log-log:

- Does the normalized pressure continuously increase?
- Does the NPI plot have a single continuous stem?
- Are outliers being misinterpreted as boundary-dominated flow?

Does the normalized pressure continuously increase?



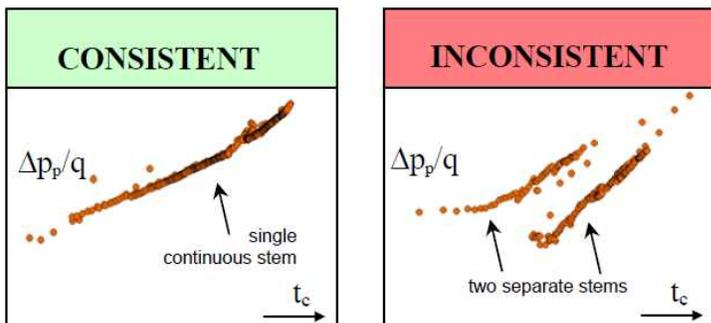
- The log-log plot of normalized pressure ($\Delta p_p/q$) versus material balance time (G_p/q) should have an increasing trend.
- A step change in rate causes a sudden deviation from the inclining trend, but if the data is consistent, it reverts to the original trend.

Reasons for inconsistencies:

- A decreasing trend indicates non-reservoir effects, such as near wellbore cleanup, improv-

ing skin, wellbore liquid unloading (if pressures have been calculated from wellhead data).

Does the NPI plot have a single continuous stem?

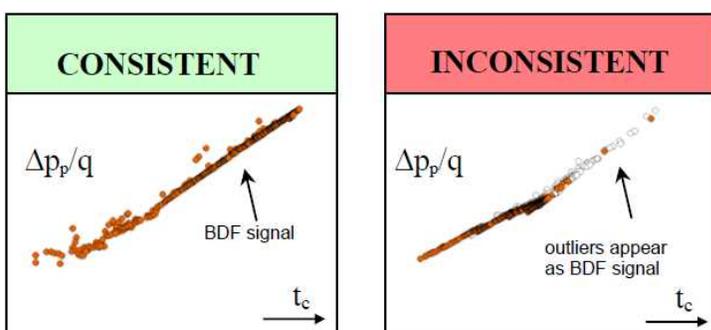


- Changes in rate or pressure are accounted for in the NPI plot, and should *not* cause it to develop multiple stems.
- In the case of multiple stems, the stem that represents the correct reservoir model should be used for analysis.

Reasons for inconsistencies:

- The reservoir model has changed (for example, work-over, recompletion, refrac, etc.).
- The wellhead pressures measurement location may have changed (for example, tubing, casing, before / after valve), or there may have been a change of flow path or tubulars.

Are outliers being misinterpreted as boundary-dominated flow?



- Outliers often appear on a unit slope on the NPI plot. This can lead to an incorrect diagnosis of reservoir depletion, or boundary-dominated flow (BDF).

Reasons for inconsistencies:

- Outliers have been included in the analyses. Apply the median filter to remove outliers.

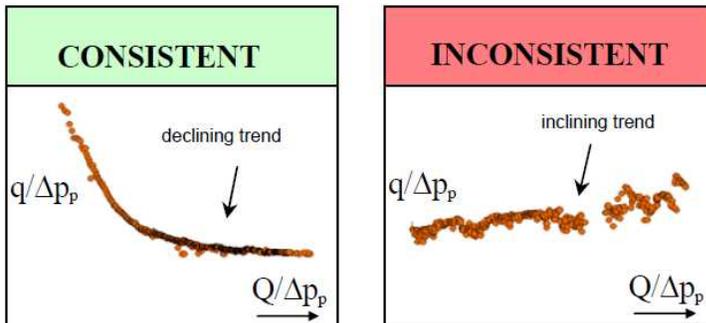
FMB rate (Cartesian)

[Return to the data diagnostics flowchart](#)

These questions apply to the flowing material balance (FMB) rate – Cartesian:

- Does the normalized rate continuously decline?
- Does the FMB-Rate plot have a single continuous stem?

Does the normalized rate continuously decline?

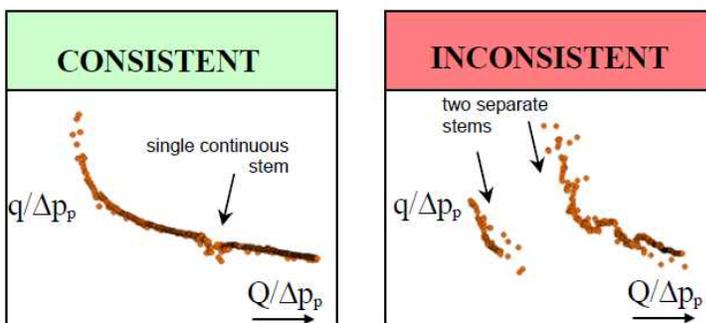


- The Cartesian plot of normalized rate ($q/\Delta p_p$) versus normalized cumulative production ($Q/\Delta p_p$) should have a declining trend, and tend towards a straight line.

Reasons for inconsistencies:

- An increasing trend indicates non-reservoir effects, such as near wellbore cleanup, improving skin, wellbore liquid unloading (if pressures have been calculated from wellhead data).

Does the FMB-Rate plot have a single continuous stem?



- Changes in rate or pressure are accounted for in the FMB-rate plot, and should *not* cause it to develop multiple stems.
- In the case of multiple stems, the stem representing the correct reservoir model should be used for the analysis.

Reasons for inconsistencies:

- The reservoir model has changed (for example, work-over, recompletion, refrac, etc.).
- The wellhead pressures measurement location may have changed (for example, tubing, casing, before / after valve), or there may have been a change of flow path or tubulars.

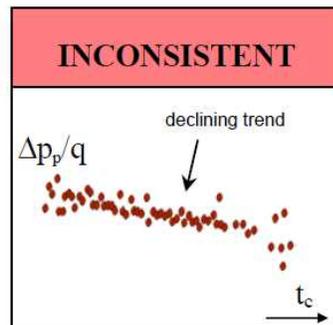
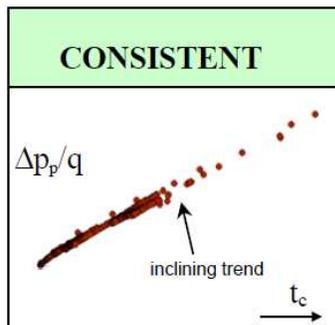
FMB pressure (Cartesian)

[Return to the data diagnostics flowchart](#)

These questions apply to flowing material balance (FMB) pressure – Cartesian:

- Does the normalized pressure continuously increase?
- Does the FMB-Pressure plot have a single continuous stem?

Does the normalized pressure continuously increase?

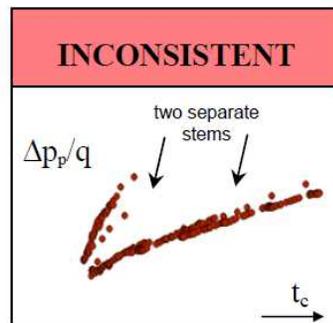
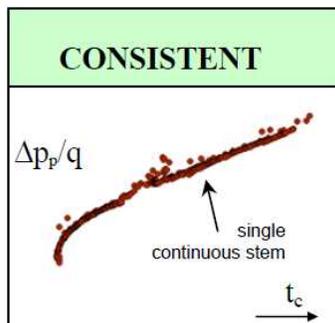


- The Cartesian plot of normalized pressure ($\Delta p_p/q$) versus material balance time (G_p/q) should have an inclining trend and tend towards a straight line.

Reasons for inconsistencies:

- A decreasing trend indicates non-reservoir effects, such as near wellbore cleanup, improving skin, wellbore liquid unloading (if pressures have been calculated from wellhead data).

Does the FMB-Pressure plot have a single continuous stem?



- Changes in rate or pressure are accounted for in the FMB-pressure plot, and should *not* cause it to develop multiple stems.
- In the case of multiple stems, the stem that represents the correct reservoir model should be used for the analysis.

Reasons for inconsistencies:

- The reservoir model has changed (for example, work-over, recompletion, refrac, etc.).
- The wellhead pressures measurement location may have changed (for example, tubing, casing, before / after valve), or

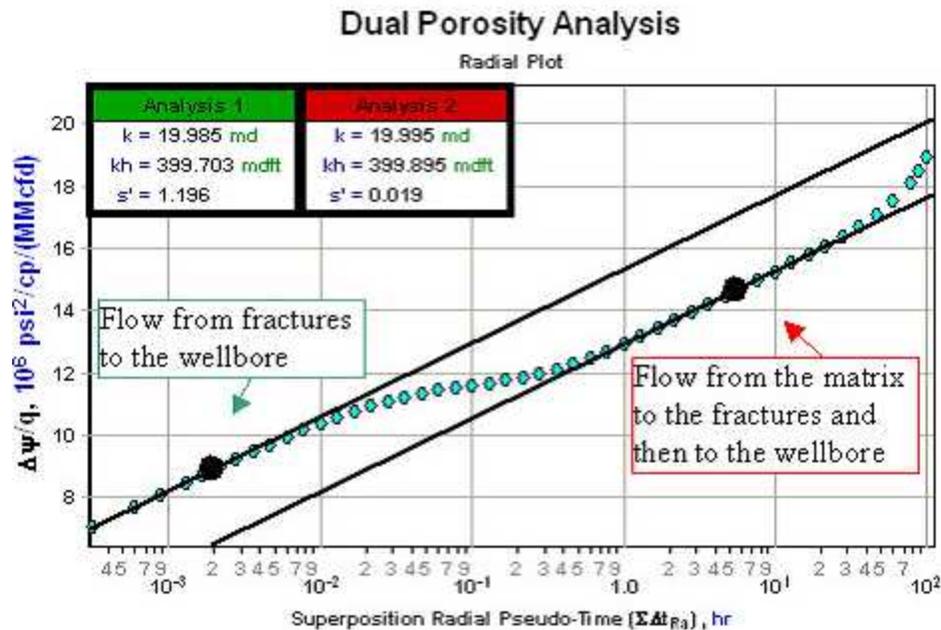
there may have been a change of flow path or tubulars.

Dual porosity

Naturally fractured reservoirs have two distinct porosities, one in the matrix and one in the fractures. Although naturally fractured reservoirs consist of irregular fractures, they can be represented by equivalent homogeneous dual porosity systems (Warren and Root (1963)).

Quite often, the volume of hydrocarbon stored within the natural fractures is much lower than is stored in the matrix. In dual porosity systems, the natural fractures have much higher permeability than the matrix. When the well begins to flow, fluid travels from the high permeability natural fractures to the wellbore and is rapidly produced. Once the natural fractures have been drained, the large volume of hydrocarbons contained within the bulk of the reservoir (matrix) begins to flow. These hydrocarbons flow to nearby natural fractures and virtually all of the fluid is transported to the wellbore via these fractures.

The signature of dual porosity systems on a semi-log plot is two parallel lines as shown below.



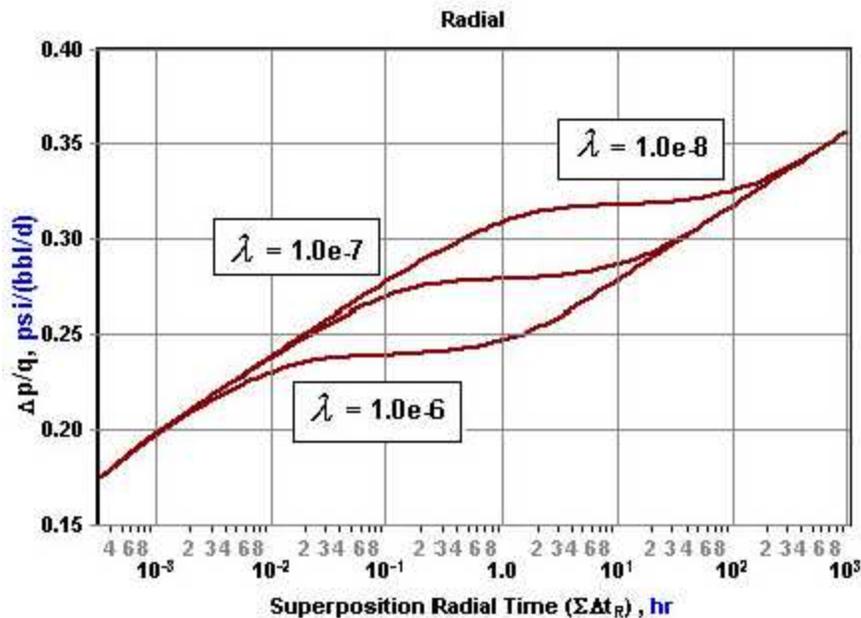
The first semi-log straight line is observed at early time and represents radial flow as the fluid, initially in the fractures, travels to the wellbore. The second semi-log straight line occurs when the

fractures deliver fluid from the matrix to the wellbore. The transition period between the two semi-log straight lines occurs when fluid begins to flow from the matrix to the fractures but has not yet reached a state of equilibrium.

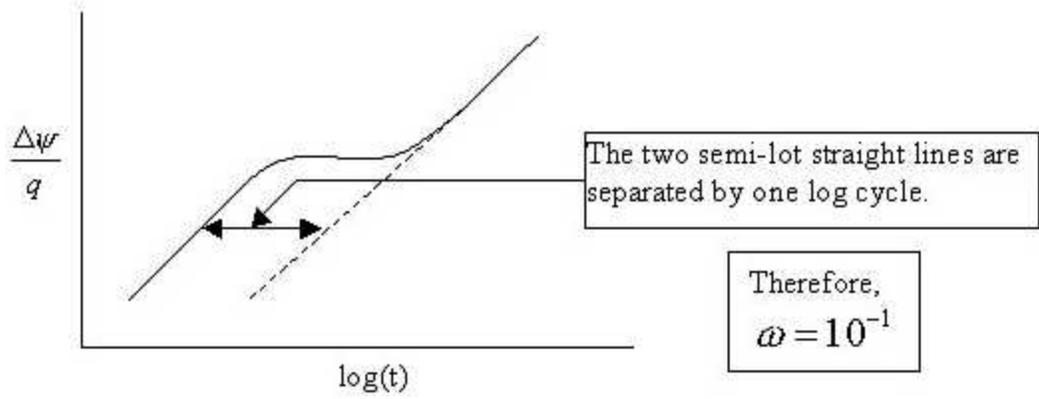
Be aware that dual porosity, especially the first semi-log straight line, may not be noticeable even if the reservoir is naturally fractured because wellbore storage effects could affect the data.

Naturally fractured reservoirs are characterized by the interporosity flow coefficient (λ), the storativity ratio (ω), and the type of interporosity flow.

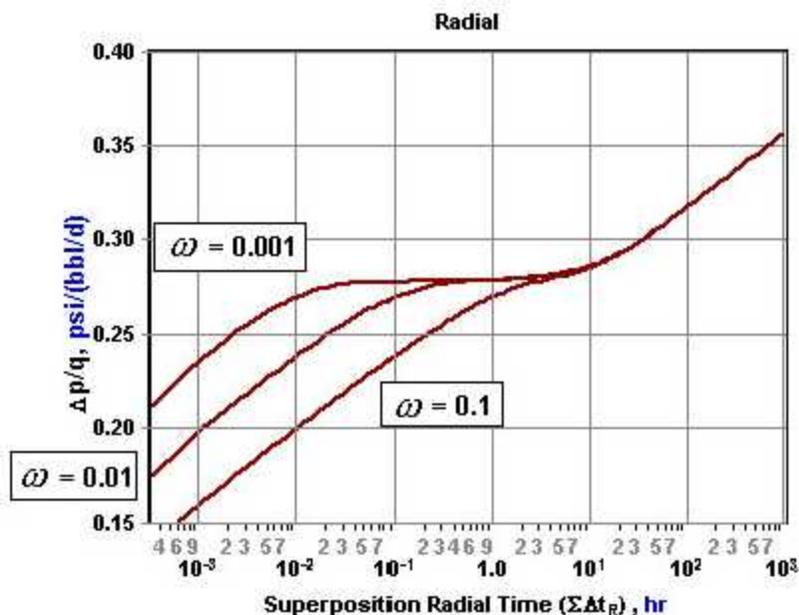
As shown in the plot below, as the interporosity flow coefficient decreases, the transition between the two semi-log straight lines is delayed. That is, the larger the fracture permeability is in comparison to that of the matrix, the more time the fractures will have to drain before the contribution from the matrix becomes significant.



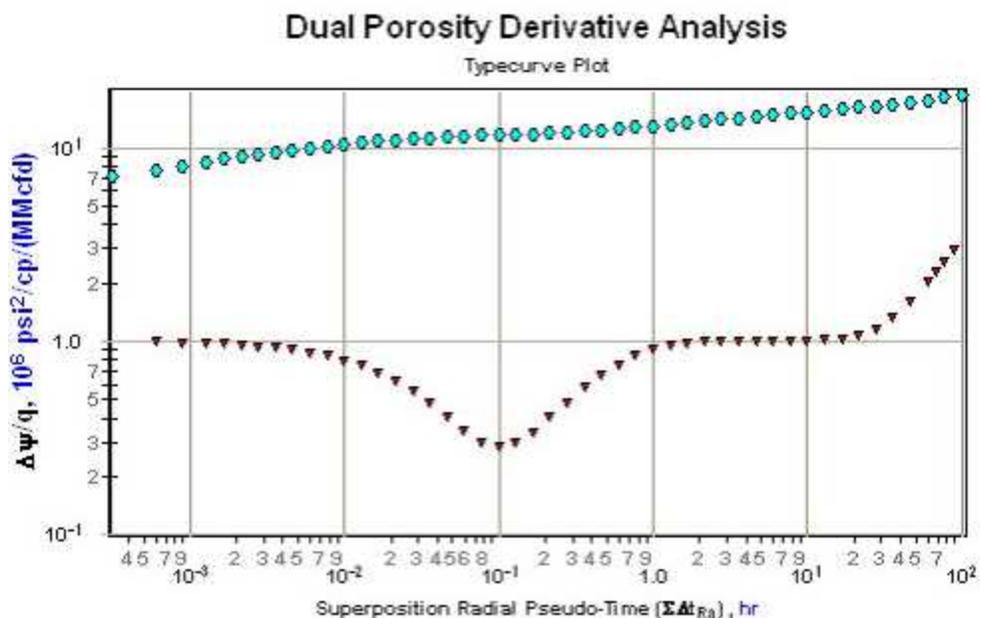
The storativity ratio (ω), essentially represents the time separation in log cycles between the two semi-log straight lines as shown below.



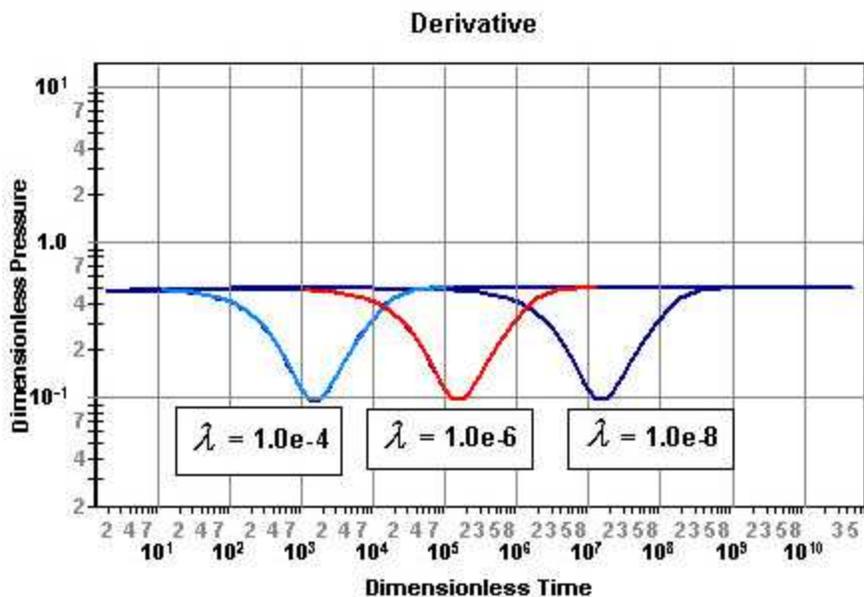
A storativity ratio of one is a single porosity system with all of the reserves inside the fractures, and a storativity ratio approaching zero is a single porosity reservoir with all the reserves inside the matrix. Therefore, as the storativity ratio is decreased, a greater portion of the reserves are contained in the matrix and the longer it takes for the matrix and fracture system to reach a state of equilibrium. This is shown in the following plot:

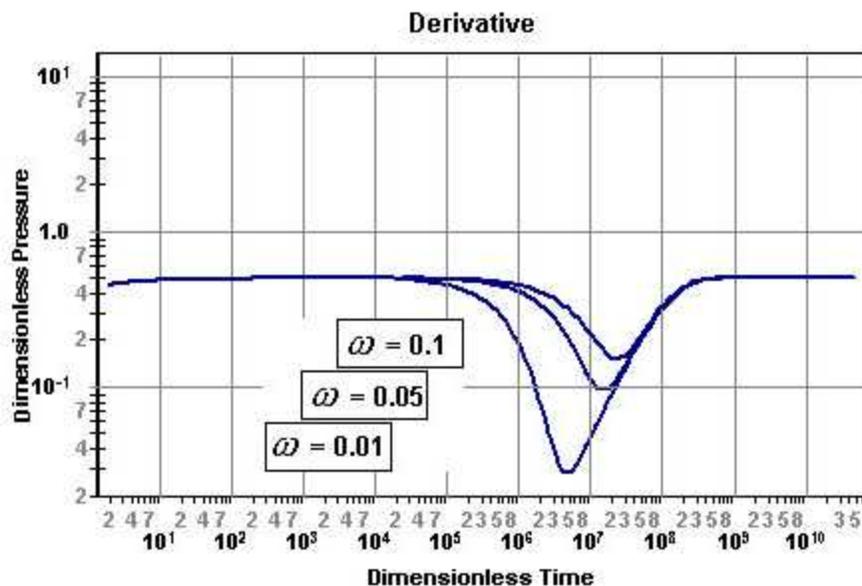


The signature of dual porosity on a derivative plot shows up as two regions of radial flow with the same conductivity, kh , separated by a transition period. This is often referred to as the dual porosity dip.



As in the case for the semi-log plot, the shape and location of this transition period or dual porosity signature are defined by the interporosity flow coefficient (λ) and the storativity ratio (ω) as shown in the plots below.





It is important to note that when analyzing dual porosity data that the value of apparent or total skin (s') should always be taken from the second semi-log straight line or the second radial flow region on the derivative plot.

Interporosity flow coefficient (λ)

In a dual porosity reservoir, the interporosity flow coefficient is defined as the ratio of the permeability of the matrix (k_m) to that of the fractures (k_f) defined as:

$$\lambda = \alpha \cdot r_w^2 \frac{k_m}{k_f}$$

Note that the geometric coefficient (α) accounts for the shape of the matrix blocks. The interporosity flow coefficient is usually in the range of 10^{-4} to 10^{-8} and is always used in conjunction with the storativity ratio in dual porosity reservoirs.

Interporosity skin (s_{dp})

Interporosity skin is used in the transient interporosity flow dual porosity model. It is defined as the skin or pressure drop at the interface between the two porosities (matrix and fractures). If this skin is large, then this transient model becomes equivalent to the pseudo-steady state interporosity flow model.

Storativity ratio (ω)

In a dual porosity reservoir, the storativity ratio is defined as the fraction of the total pore volume associated with one of the porosities. Specifically, in a naturally fractured reservoir it refers to the volume of reserves contained within the fractures and is defined as:

$$\omega = \frac{\phi_f c_{frac}}{\phi_f c_{frac} + \phi_m c_m}$$

The storativity ratio has a significant effect on the short-term deliverability of a reservoir. It is usually in the range of 0.01 to 0.1 and is always used in conjunction with the interporosity flow coefficient in dual porosity reservoirs.

Types of interporosity flow

There are two types of interporosity flow that are used to model dual porosity systems: pseudo-steady state interporosity flow and transient interporosity flow.

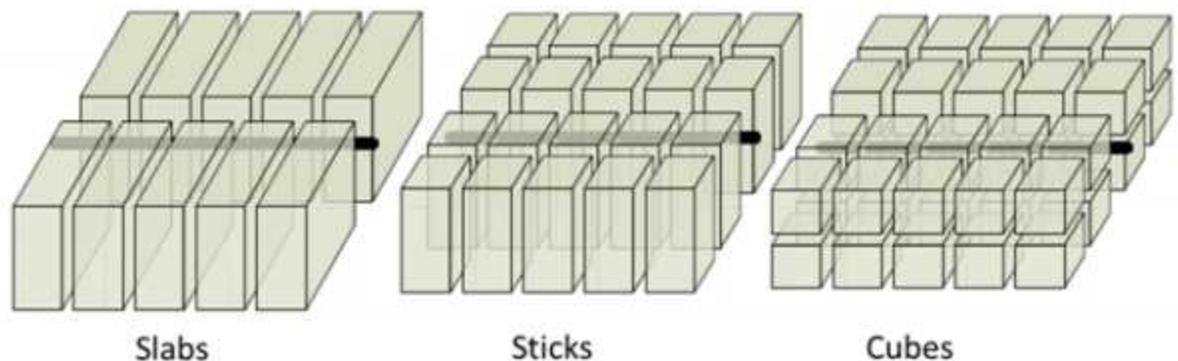
Pseudo-steady state interporosity flow

This model is the most commonly used dual porosity model and assumes that the flow between matrix and fractures is in pseudo-steady state.

Transient interporosity flow

This model assumes that the flow between the matrix and fractures is transient, and that a positive skin (s_{dp}) exists at the interface between the two porosities. If this skin is large, then this transient model becomes equivalent to the pseudo-steady state interporosity flow model.

The three types of matrix geometry for model transient interporosity flow are slabs, sticks, and cubes.



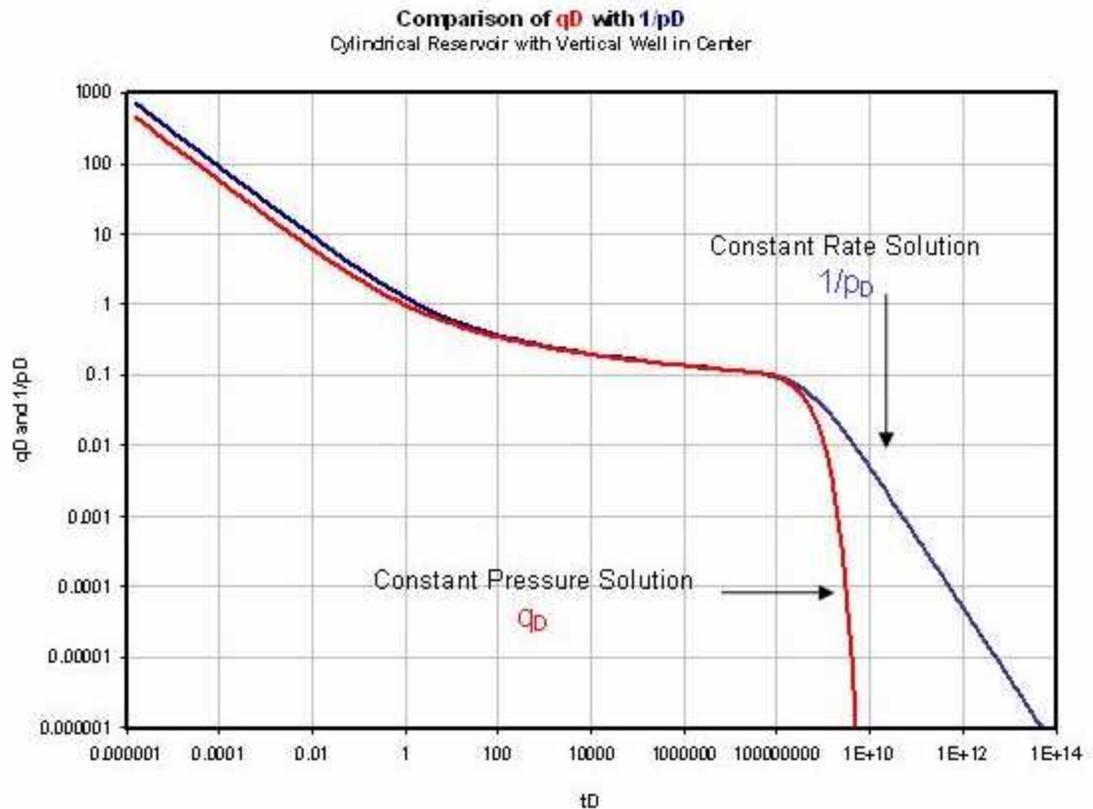
A dual porosity system gives rise to two parallel straight lines on a semi-log plot. However, often the first line is obscured by early time effects such as wellbore storage. Moreover, if the interporosity flow is of the transient mode rather than the pseudo-steady state type, then in the transition between the two parallel semi-log lines, there exists a semi-log straight line of half of the slope of one of the parallel lines. In practice, these straight lines are difficult to observe uniquely.

Note: Calculations for various types of interporosity flow are summarized by Gringarten (1984).

Equivalence of constant rate and constant pressure solutions

A well produced at a constant rate exhibits a varying (declining) sandface flowing pressure, whereas a well produced at a constant sandface pressure exhibits a varying decline rate. There is a strong symmetry between the two solutions, as both are obtained from the same equation, namely the equation that governs fluid flow in porous media. The symmetry is not exact, however, because the boundary conditions under which the two solutions are obtained are different.

The constant rate solution can be converted to a constant sandface pressure solution (and vice versa) using the principle of superposition. The constant sandface pressure solution is obtained by superposing a large number of very short constant rate solutions in time. When plotted against superposition time, the superposed constant rate solution is very similar to the constant pressure solution, provided the discretization intervals are sufficiently small. It turns out that the two solutions are quite similar during transient flow anyway, and therefore, superposition is not required to make one look like the other. However, they quickly diverge after boundary-dominated flow begins. The constant rate solution behaves like the harmonic stem of the Arps type curves, while the constant pressure solution declines exponentially. The figure below compares the two solutions by plotting the dimensionless typecurves of each.



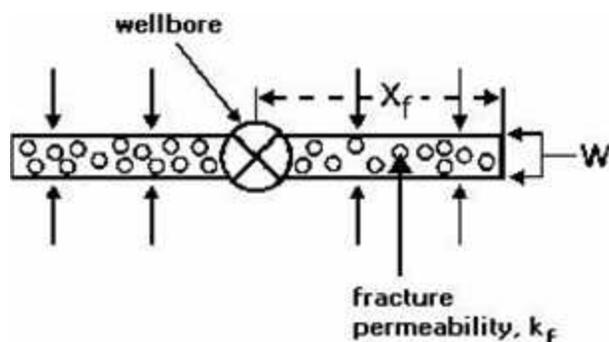
A method for forcing one solution to look like the other during boundary-dominated flow is useful because the necessity of using superposition in time would be avoided completely. Because of pressure transient analysis, diagnostic tools for analyzing the constant rate solution are widely known and understood. Therefore, there is value in being able to analyze other types of solutions using the same diagnostic tools. The concept of material balance time provides the normalization necessary to make constant pressure and constant rate solutions equivalent. Material balance time converts the boundary-dominated flow portion of the constant pressure solution into the pseudo-steady state portion of the equivalent constant rate solution. Plotting using material balance time also allows solutions with both declining rates and pressures to look like the equivalent constant rate solution.

Fracture properties

Fracture flow capacity ($k_f w_f$)

Fracture flow capacity is a measure of how conductive or how easily fluid moves through a fracture. It is defined as the product of fracture permeability (k_f) and fracture width (w_f), as shown

below:



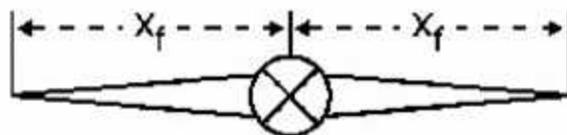
A large value of fracture flow capacity (>10,000 md ft) represents an infinite conductivity fracture, and yields a linear fracture flow response on the derivative. A small value of the fracture flow capacity (<10,000 md ft) represents a finite conductivity fracture and may yield a bilinear fracture flow response on the derivative. When the value of fracture flow capacity is divided by the product of formation permeability and fracture half-length, the result is known as the dimensionless fracture conductivity, defined as:

$$F_{CD} = \frac{k_f w_f}{k x_f}$$

This dimensionless form is a more common measure of fracture conductivity that is found in the literature.

Fracture half-length (x_f)

A hydraulic fracture is typically modeled by assuming it extends in a straight line equally on each side of the wellbore as shown in the following diagram.



As shown, the fracture half-length is the distance from the well to the tip of the fracture.

The fracture half-length depends on the size of the fracture treatment and varies from a few feet to a few hundred feet. In pressure and rate transient analysis it is estimated from the linear fracture flow analysis.

Geomechanical reservoir models

Geomechanical models simulate changes in rock properties with time and pressure. In performance-based reservoir analysis, a geomechanical model may be coupled with a flowing material balance, typecurve, analytical, numerical, or unconventional reservoir module analysis. In addition, geomechanical models are useful for, and may be necessary additions to, analyses of overpressured reservoirs. The primary properties of interest are porosity, formation compressibility (pore compressibility), and permeability. The impact of these properties on the fluid flow model are discussed in the following sections.

Porosity and formation compressibility

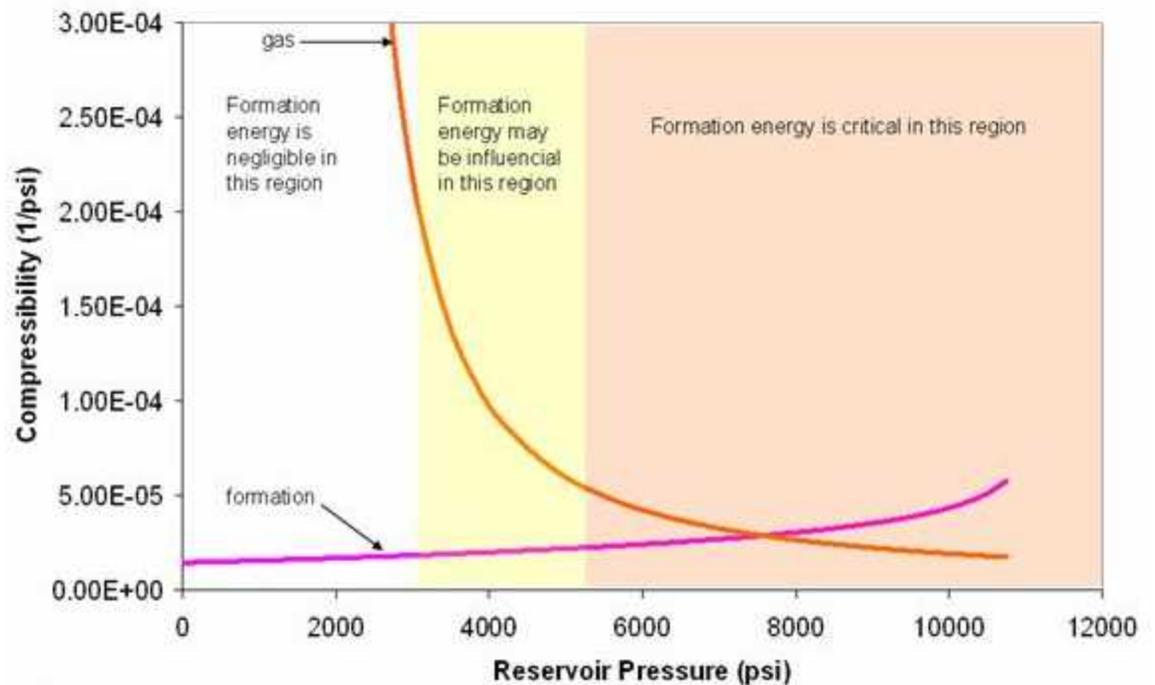
Pore volume and pore volume compressibility are related through the following equation:

$$c_f = \frac{1}{V_p} \frac{dV_p}{dp}$$

In normally pressured reservoirs, the pore volume change with pressure is considered minimal, and thus the pore volume (formation) compressibility retains a very small, constant value. However, in overpressured reservoirs, the natural compaction process is incomplete, as a large portion of the overburden remains supported by high internal pore pressure. As this pressure is released through fluid production, the pore space may reduce significantly. Thus, under overpressured conditions, formation compressibility is relatively large, and may have significant variation with pressure. This becomes important to the material balance equation, as pore compressibility is a significant energy term in overpressured reservoirs.

In normally pressured gas reservoirs, the energy of the formation is usually negligible, compared to the energy of the gas. In oil reservoirs, the formation compressibility may be significant at any pressure. The graph below compares the energies (compressibilities) of formation and fluid (gas) over a large pressure range. In areas where they are near the same order of magnitude, the formation compressibility cannot be ignored.

Compressibility vs. Pressure (Typical Gas Reservoir)



For overpressured reservoirs, there are very few published correlations. Most appear to be highly specific to area and rock type, and thus are not useful for universal application.

Hall

The most well-known and widely used correlation for formation compressibility was developed by Hall, and is a function of porosity. The Hall correlation is based on laboratory data and is considered reasonable for normally pressured sandstones. It tends to under-predict formation compressibility under high pressure conditions. This correlation is used when calculating initial formation compressibility on the Basic Reservoir Properties view.

$$c_f = 1.87 \cdot 10^{-6} \phi^{-0.415}$$

Dobrynin

The Dobrynin (1962) correlation can predict a relative change in formation compressibility over a range of net overburden pressures. It is designed for overpressured reservoirs. The correlation assumes a semi-logarithmic relationship between formation compressibility and net overburden

pressure between two limiting pressures, p_{\min} and p_{\max} . However, it does not predict the initial formation compressibility.

$$c_f = \frac{c_{f \max}}{\log\left(\frac{p_{\max}}{p_{\min}}\right)} \log\left(\frac{p_{\max}}{p_n}\right)$$

$$f_c = \frac{c_f}{c_{fi}} = \frac{\log\left(\frac{p_{\max}}{p_n}\right)}{\log\left(\frac{p_{\max}}{p_{ni}}\right)}$$

$$p_{\max} = 30000 \text{ psi}$$

$$p_n = p_e + \alpha (p_i - p)$$

Laurent et al. (1993) propose an empirical correlation for Biot Coefficient (α):

$$\alpha = 1.75 \phi^{0.51}$$

The Dobrynin correlation is considered a reasonable predictor of variation in formation compressibility, provided that the following conditions are met:

- Net overburden pressure must lie within the range of p_{\min} and p_{\max} (usually 150 to 30,000 psi)
- Overburden pressure must be higher than the product of the initial pressure and Biot's number (initial net overburden pressure must be greater than zero)

The Dobrynin correlation may be used to generate a continuous compressibility profile using a known formation compressibility value:

- Initial formation compressibility (usually between 10 and 80 microcips for overpressured reservoirs)
- Overburden pressure gradient (Pgrd, psi/ft)
- Reservoir depth (ft)

Formation compressibility is then solved for any value of pressure.

Pressure-dependent permeability

In the standard pressure transient equations, permeability is usually considered to be constant. However, there are several situations in which this assumption may not be a valid:

- Compaction in overpressured reservoirs
- Very low permeability reservoirs (in general)
- Unconsolidated and/or fractured formations

Variable permeability is an important (and sometimes critical) consideration, with regards to the fluid flow model. As a result of pore volume reduction during fluid withdrawal, the available flow area is reduced, and thus the permeability decreases with pressure. As with formation compressibility, the variable permeability effect is greatest in overpressured conditions. The process of pore volume collapse in overpressured reservoirs is referred to as compaction.

One way to account for a variable permeability over time is to modify the definition of pseudo-pressure and pseudo-time. Another way to account for variable permeability is through the use of formation compressibility correlations.

Yilmaz and Nur

Yilmaz and Nur present a generic correlation, suitable for the pressure variable permeability observed in extremely low permeability reservoirs. The correlation introduces a "permeability modulus" (γ) which has a form identical to compressibility. The magnitude of the permeability modulus is a strong function of the formation compressibility.

$$\gamma = \frac{1}{k} \frac{dk}{dp}$$

$$\frac{k}{k_i} = e^{-\gamma(p_i - p)}$$

Dobrynin

Dobrynin presents a more detailed correlation, designed for overpressured reservoirs, which relates the fractional change in permeability due to formation compressibility, overburden pressure, and a dimensionless correlation factor (γ). Between a certain minimum and maximum pressure range (p_{\min} and p_{\max}), this correlation produces a semi-log straight line.

$$\frac{\Delta k}{k} = 2(1 + \gamma) c_f^{\max} \left[p_{\min} + \frac{p_o}{\log\left(\frac{p_{\max}}{p_{\min}}\right)} \left[\log\left(\frac{p_{\max}}{p_o}\right) + 0.434 - \frac{p_{\min}}{p_o} \left[\log\left(\frac{p_{\max}}{p_{\min}}\right) + 0.434 \right] \right] \right]$$

where:

γ is 0.33 for uniform pore distribution or very high pore compressibility, higher for poorly sorted sandstones with low pore compressibility.

The equation below relates the permeability at any pore pressure to that at conditions of zero net overburden pressure:

$$\frac{k_p}{k} = 1 - 2(1 + \gamma) c_f^{\max} \left[p_{\min} + \frac{p_e - \alpha \bar{p}}{\log\left(\frac{p_{\max}}{p_{\min}}\right)} \left[\log\left(\frac{p_{\max}}{p_e - \alpha \bar{p}}\right) + 0.434 - \frac{p_{\min}}{p_e - \alpha \bar{p}} \left[\log\left(\frac{p_{\max}}{p_{\min}}\right) + 0.434 \right] \right] \right]$$

It is more suitable to have an equation that relates permeability at any pressure to permeability at initial conditions, thus we rewrite the above as follows.

$$\frac{k_p}{k_i} = \frac{\frac{k_p}{k}}{\frac{k_i}{k}} = \frac{1 - 2(1 + \gamma) c_f^{\max} \left[p_{\min} + \frac{p_e - \alpha \bar{p}}{\log\left(\frac{p_{\max}}{p_{\min}}\right)} \left[\log\left(\frac{p_{\max}}{p_e - \alpha \bar{p}}\right) + 0.434 - \frac{p_{\min}}{p_e - \alpha \bar{p}} \left[\log\left(\frac{p_{\max}}{p_{\min}}\right) + 0.434 \right] \right] \right]}{1 - 2(1 + \gamma) c_f^{\max} \left[p_{\min} + \frac{p_e - \alpha p_i}{\log\left(\frac{p_{\max}}{p_{\min}}\right)} \left[\log\left(\frac{p_{\max}}{p_e - \alpha p_i}\right) + 0.434 - \frac{p_{\min}}{p_e - \alpha p_i} \left[\log\left(\frac{p_{\max}}{p_{\min}}\right) + 0.434 \right] \right] \right]}$$

where:

Biot's Number default: 0.85 to 1

Maximum Formation Compressibility default: 30 to 80 microcips

P_{\max} = 30,000 psi

P_{\min} = 150 psi

Geomechanical effects for oil analytical models

This content applies to water analytical models as well.

Background

Geomechanical effects are useful for (and may be necessary additions to) the analysis of over-pressured reservoirs. The major geomechanical effects are:

- Pressure-dependent permeability effect (Yilmaz and Nur correlation)
- Pressure-dependent formation compressibility effect (Dobrynin correlation)

Permeability changes are incorporated into a special formulation of pseudo-pressure for oil, but they also enter into the definition of pseudo-time. In addition, formation compressibility changes are incorporated into the definition of pseudo-time.

Implementation notes

Only the pseudo-pressure aspect of pressure-dependent permeability has been implemented. To be consistent with standard analytical model formulations, the pseudo-pressure for oil assumes a constant formation volume factor and constant viscosity.

Pseudo-time (which is affected by both changing permeability and by compressibility) *has not been implemented*.

Consequences:

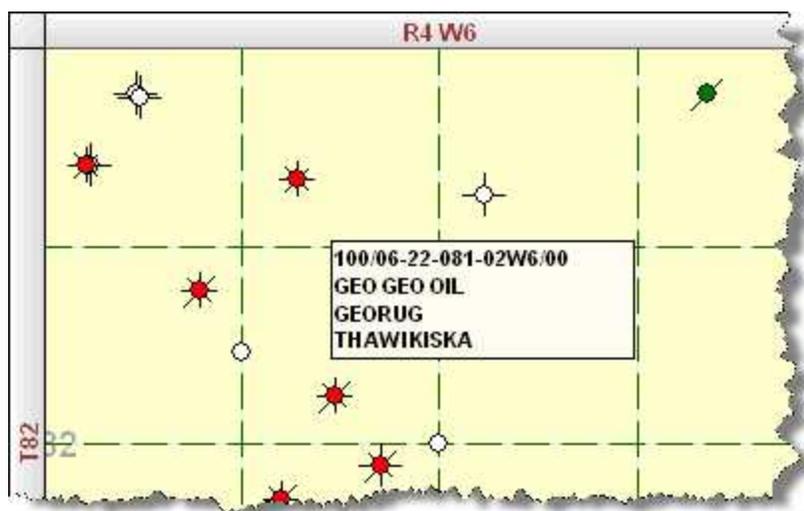
- By using regular time instead of pseudo-time for oil, forecasts tend to be more conservative. The degree of conservativeness is directly related to the combined effect of permeability, and formation compressibility variations with pressure.
- By using constant oil properties, slight changes in pressure, volume, temperature (PVT) are not be tracked (this is a relatively minor issue).

Recommended Usage:

- For oil reservoirs that stay above the bubble point
- For oil reservoirs that are at or below the bubble point, but with total compressibility that accounts for gas coming out of solution.

GIS theory

The geographic information system (GIS) is a system for gathering, processing, and presenting data based on geographical references.



This section describes how locations are displayed using the different mapping systems. There are five grid display modes supported in Harmony Enterprise:

1. Cartesian
2. Dominion Land Survey (DLS)
3. Latitude / Longitude
4. National Topographic Map Numbering System (NTS)
5. Universal Transverse Mercator (UTM)

Cartesian

Cartesian coordinates describe a location in terms of distance from a defined reference point. The X axis, which represents longitude, increases in the east direction. The Y axis, which represents latitude, increases in the north direction.

Example location: -317 km, 6532 km

X Axis (East/West)	Y Axis (North/South)
317 km west	6532 km north

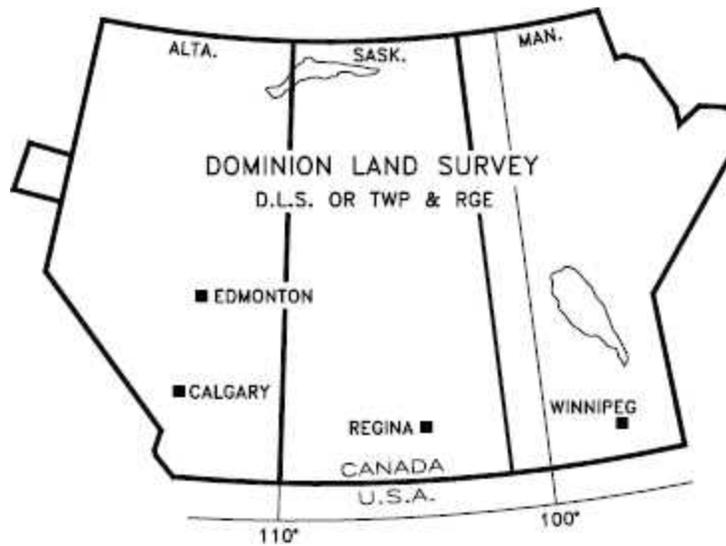
East / West: The negative sign indicates that the location is to the west of the defined reference point.

North / South: The location is to the north of the reference point. In most cases this reference will be the equator.

Dominion land survey

The Dominion Land Survey (DLS) system is used in the Canadian provinces of Alberta, Saskatchewan, Manitoba, and a small portion of British Columbia.

Areas in Canada where the DLS system is used:



Example Location: 100/04-11-082-04W6/0

We can read the parts of the unique well identifier (UWI) as the following:

UWI Format	Location Exception	Legal Sub-division	Section	Township	Range	Meridian	Event Sequence Code
1	00	04	11	082	04	w6	0

UWI format

This number identifies the use of a DLS system.

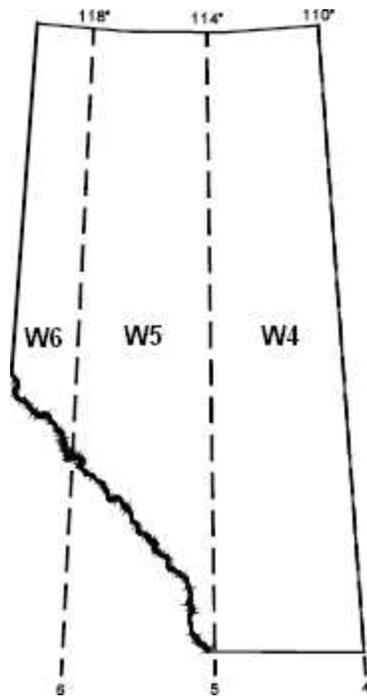
Location exception code

This is used when there is more than one well drilled per legal subdivision. For more details on what can be included in the exception code, see Energy Resource Conservation Board's Guide 59.

Meridian

The meridians are 4 degrees of longitude wide that divide the DLS provinces. The First or Primary Meridian is located at 97°27' 28.41" west, which is just west of Winnipeg, Manitoba. Meridians west of the Primary Meridian are designated sequentially as "W1M", "W2M" to "W6M". Similarly, meridians east of the Primary Meridian are designated sequentially as "E1M", "E2M", etc. The fourth meridian west of the Primary (W4M) corresponds to 110 degrees west, and forms the Alberta-Saskatchewan border.

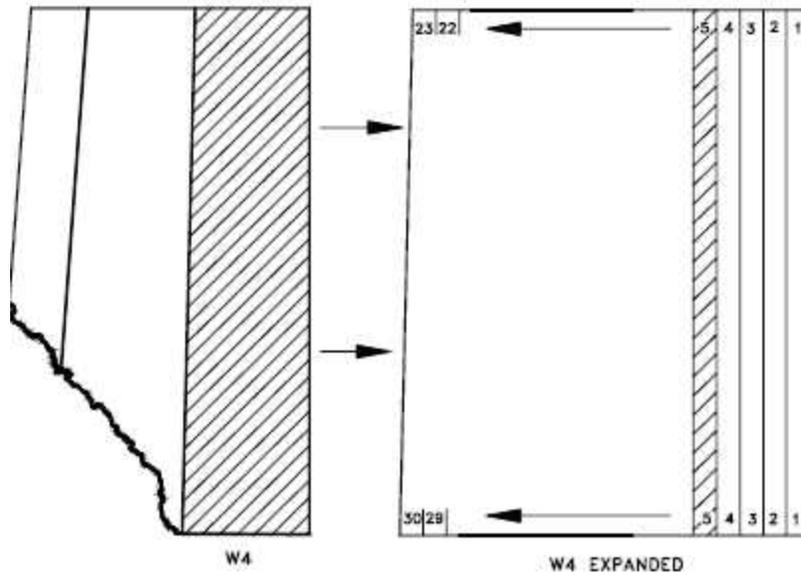
The meridians corresponding to Alberta, Canada:



Range

The ranges further divide the meridians. At the southern edge of Alberta, there are 30 range lines per meridian. The number of ranges per meridian decreases as the latitude increases. Each range is 6 miles (9.7 kilometers) wide.

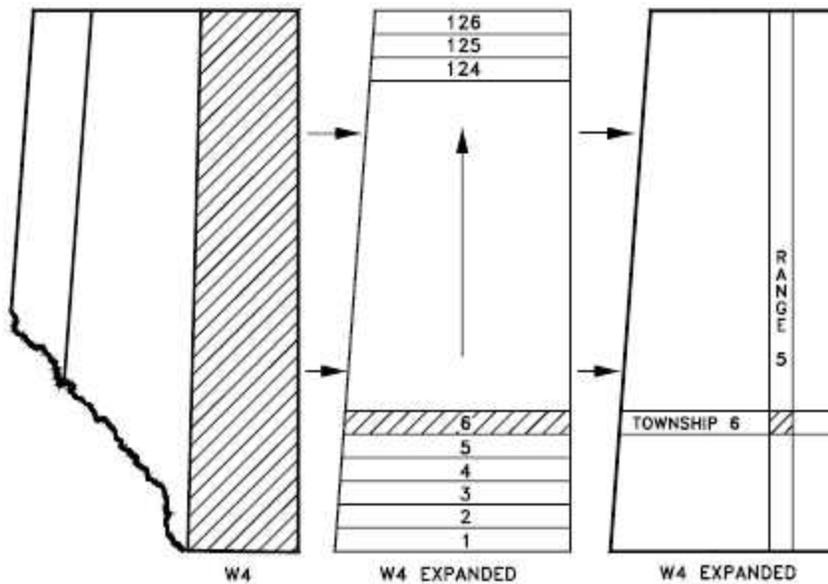
Ranges in Alberta:



Townships

The townships divide the provinces up in the north-south direction from the Canada-USA border to the Arctic Circle. There are 126 township lines in Alberta. Each township is 6 miles (9.7 km) north-south.

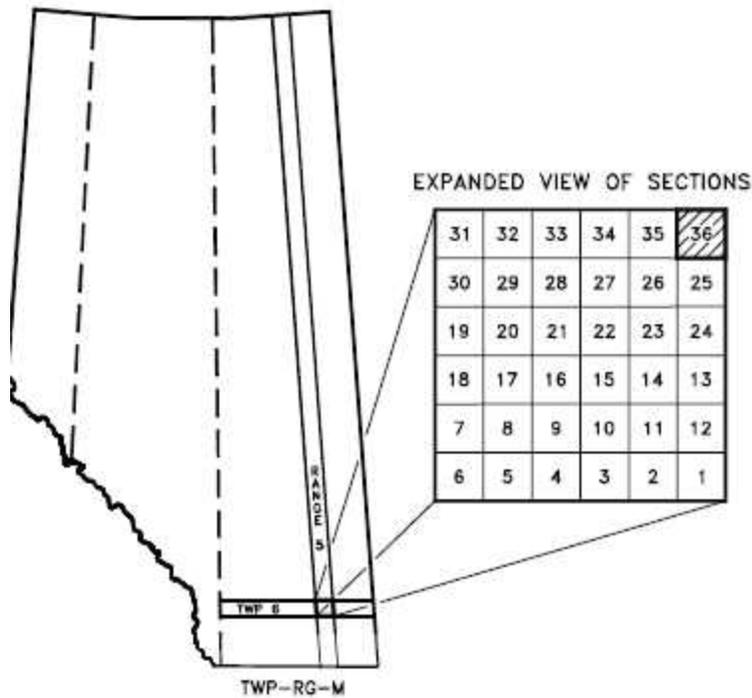
Expanded view of ranges in Alberta:



Sections

A square one range wide by one township north-south contains 36 sections. Each section is 1 mile (1.6km) per side.

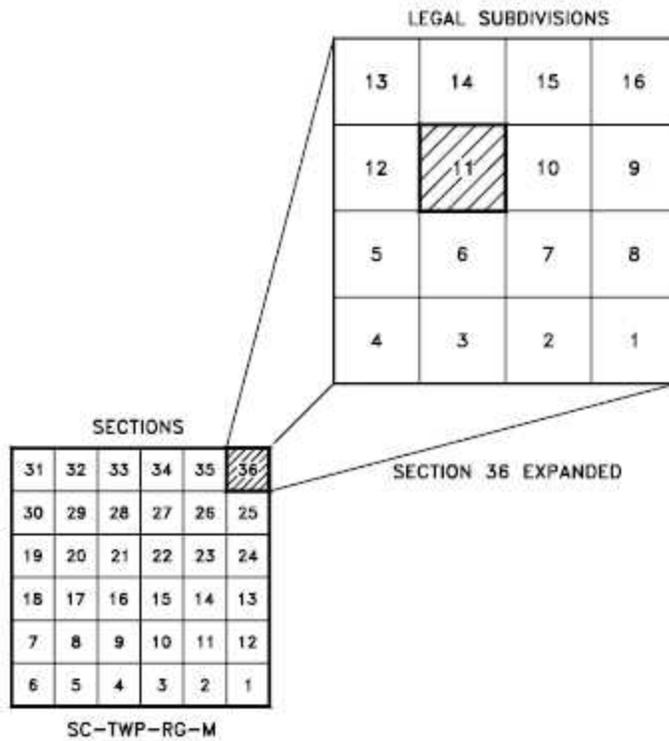
Expanded view of sections:



Legal subdivision

Each section is further divided into 16 legal subdivisions (LSD). An LSD is the smallest division in the DLS system. Each LSD is a square of one-quarter-mile, or 1320 ft (402m) per side.

Expanded view of LSD:

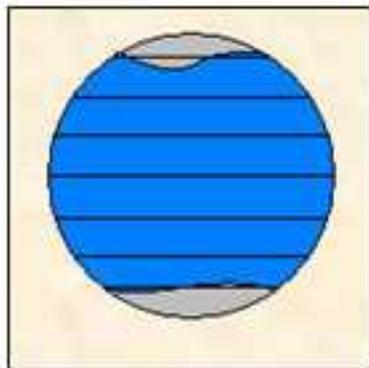


Event sequence

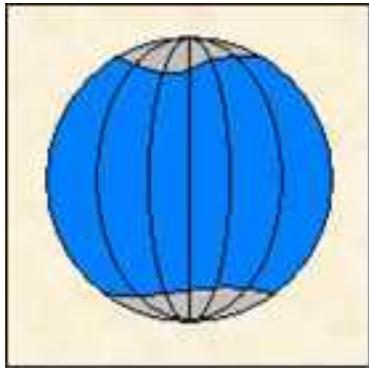
Indicates chronological sequence of drilling or completion activities.

Latitude / longitude

Latitude is a measure of how far a point is from the Earth's equator. Latitudes may vary from 0 to 90 in both north and south directions. Latitude lines are all parallel. There is a constant distance separating latitude lines of about 110 km (69 miles) per degree.



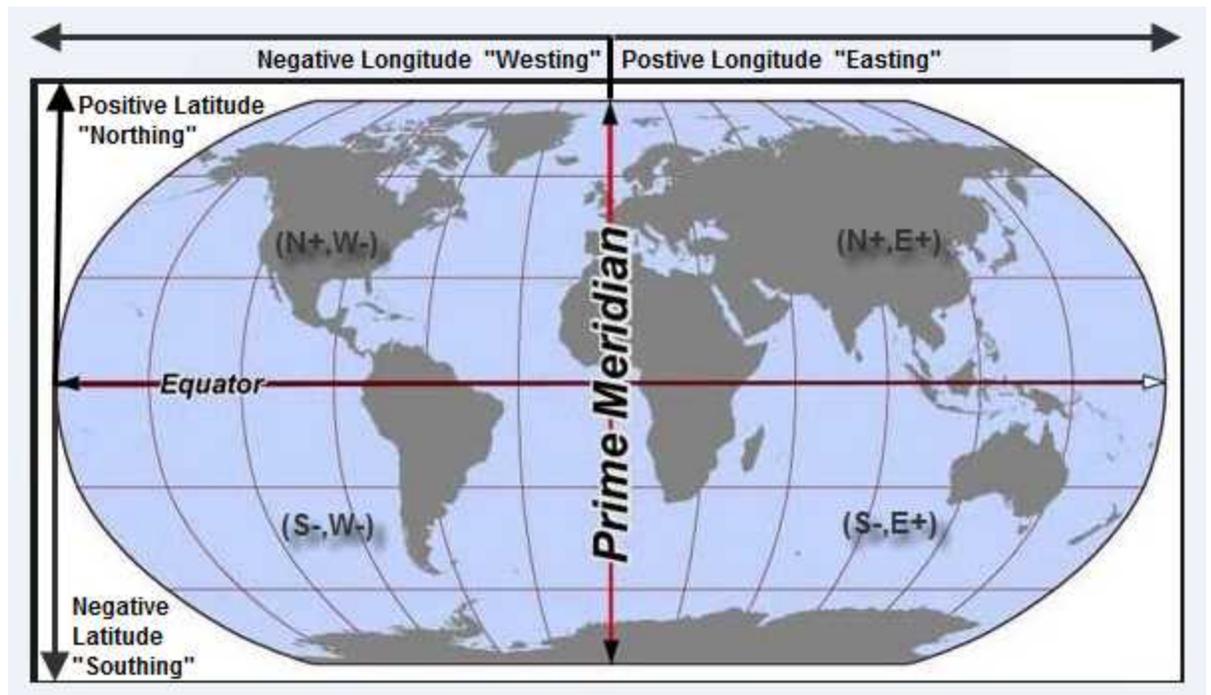
Longitude is an angular distance that is measured using the prime meridian as a reference. The prime meridian is an imaginary line that connects the North and South poles while passing through Greenwich, England. The ranges for longitudes are 0 - 180 East and West. Longitude lines are not parallel. The distance between two points that are separated by a fixed longitude depends on their latitude. Longitude varies from about 110 km (69 miles) per degree at the equator to a few meters (or feet) per degree at the poles.



To further divide degrees of latitude and longitude seconds and minutes are used:

- 1 degree = 1^o = 60 minutes
- 1 minute = 60 seconds

Since Harmony Enterprise only accepts a decimal notation for latitude and longitude, you need to convert your values. You can use an online calculator. Or convert by hand, by dividing the minutes by 60 and the seconds by 3600 (60 x 60), followed by adding these values together with the degrees. If you attempt to bring in latitude / longitude, Harmony Enterprise does not read the directional script typically given at the end of a coordinate pair (e.g., N for "Northing", etc.). Instead, Harmony Enterprise reads whether the number is positive or negative.

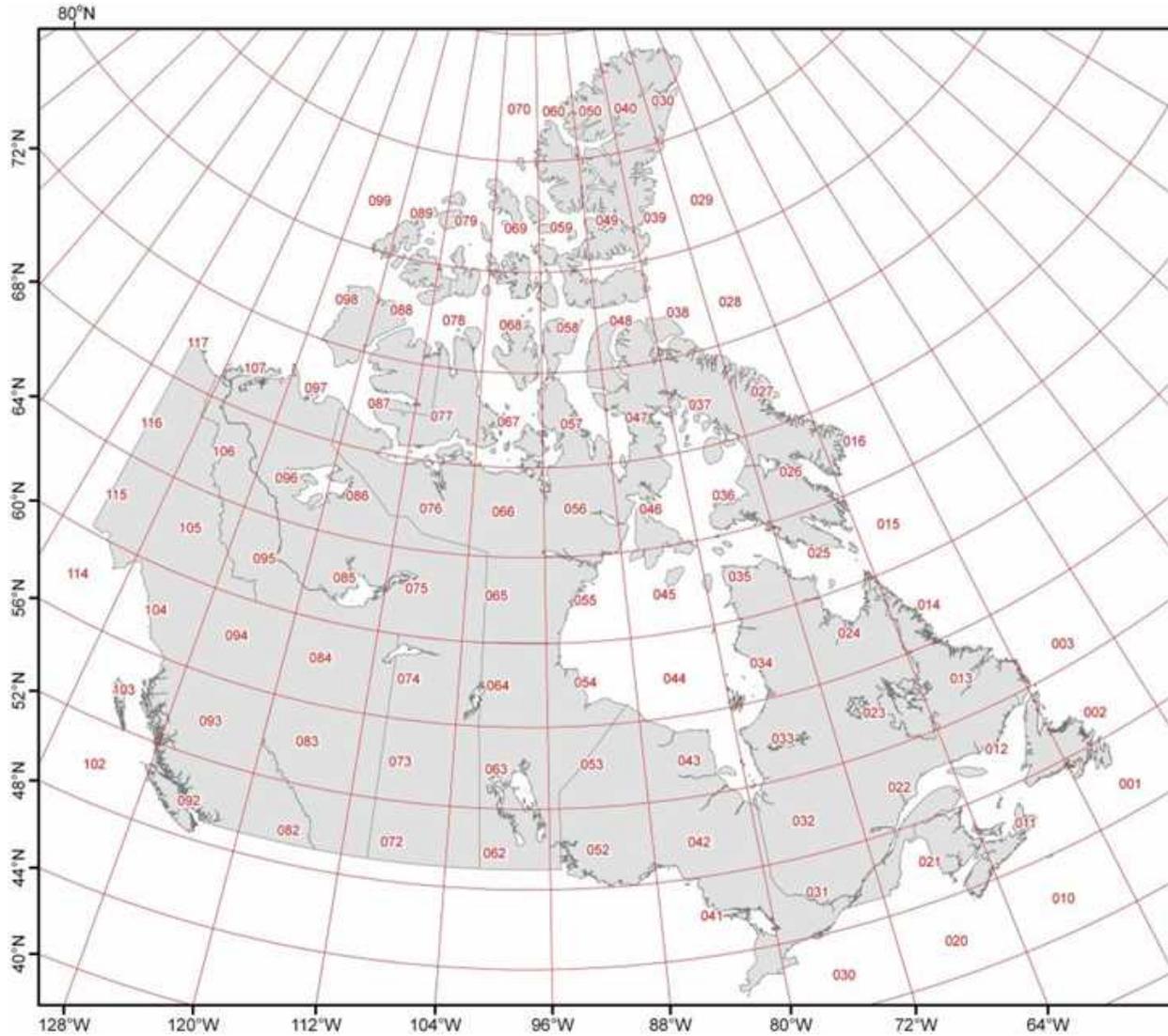


As an example of latitude and longitude, here are the approximate locations of a few cities around the world:

Location	Latitude	Longitude	Notes
Greenwich, England	51 ^o , 29 min N	0 ^o , 0 min	This is the reference point for longitude.
Calgary, Canada	51 ^o , 3 min N	114 ^o , 3 min W	This city is located north of the Equator and to the west of Greenwich.
Perth, Australia	31 ^o , 57 min S	115 ^o , 52 min E	This city is located south of the Equator and to the east of Greenwich.

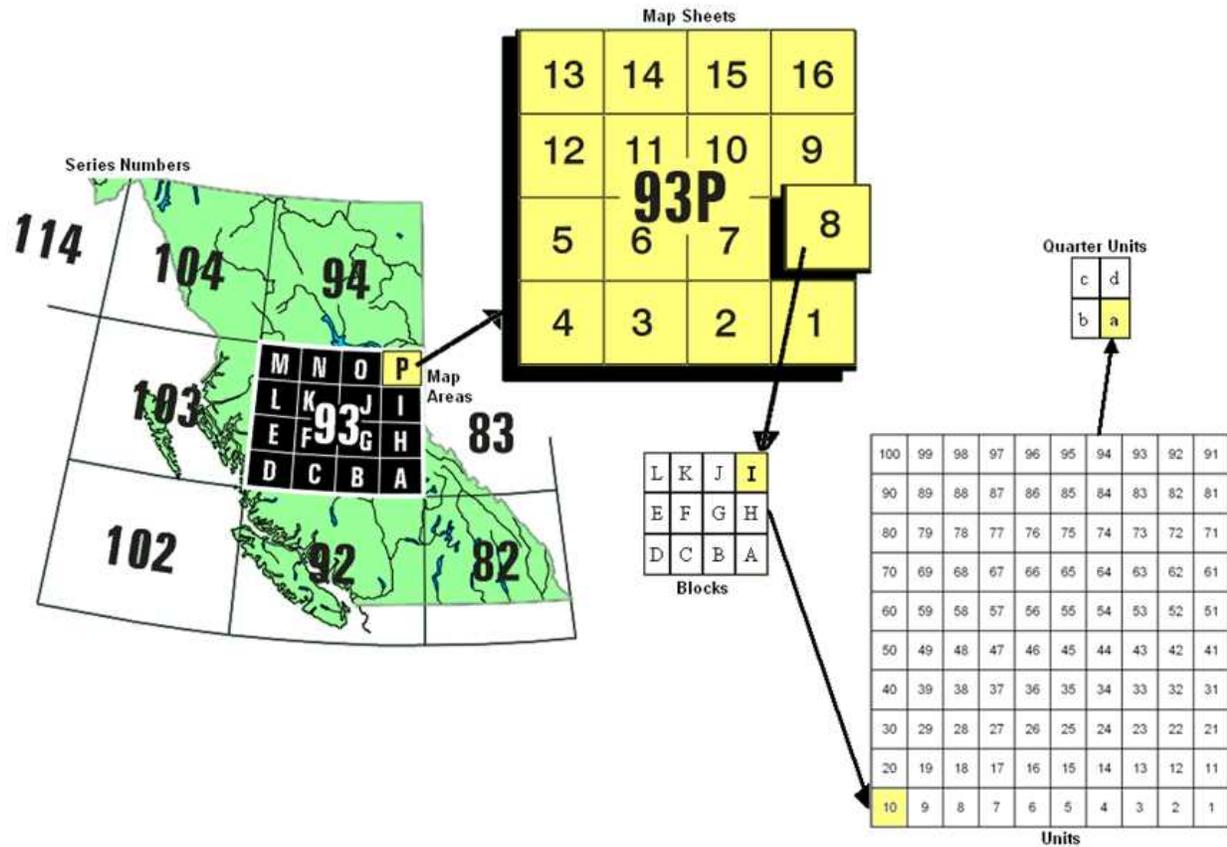
National topographic map numbering system

The National Topographic Map Numbering System (NTS) is a system used by Canada to provide general purpose maps of the country.



Example Location: a-10-D-93-P-2

Quarter Units	Units	Blocks	Series Numbers	Map Areas	Map Sheets
a	10	1	93	P	8



Series numbers

The series numbers identify rectangular areas that have a width of 8 degrees of longitude (width) and 4 degrees of latitude (north south). Series number 93 is located in the province of British Columbia.

Map areas

The map areas divide the series numbers into 16 pieces that are labeled A to P. Each map area is 2 degrees of longitude (width) and 1 degrees of latitude (north south).

Map sheets

Each map area is divided into 16 numbered map sheets.

Blocks

The map sheets are divided into 12 blocks that are labeled from A to L.

Units

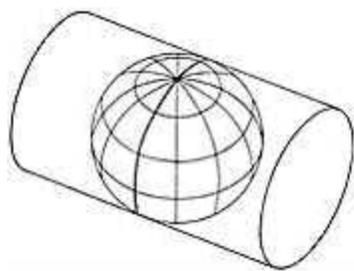
The blocks are subdivided into 100 units. The direction of the numbers is always towards the left, unlike the numbering of map sheets.

Quarter units

Each block is subdivided into quarter units labeled a to d.

Universal transverse mercator

The universal transverse mercator (UTM) grid is an attempt to draw the earth on a cylindrical projection. The word transverse implies that the cylinder is "wrapped" around the earth in a north-south direction, as shown in the following figure.



The equator is used as the reference point in the north/south direction. The east/west reference is decided upon by the user. Caution should be used in using coordinates that are very far apart as UTM zones are intended to be only 6 degrees longitude in width.

Example location: 317km W, 6532km N

East/West	North/South
317 km west	6532 km north

East / West: The location is 317 km (198 miles) to the west (W) of longitudinal reference point.

North / South: The location is that the well is 6532 km (4083 miles) to the north (N) of the equator.

Interpolation theory

Values should be interpolated using the following equation:

$$y = y_1 + \frac{(y_2 - y_1)(t - t_1)}{(t_2 - t_1)}$$

Where:

y = Interpolated value

y₁ = Known lower-bound value

y₂ = Known upper-bound value

t = Mid-period time at the interpolate value

t₁ = Mid-period time at the known lower-bound value

t₂ = Mid-period time at the known upper-bound value

Langmuir isotherm

Adsorption

Shale reservoirs have immense capacity for methane storage. The mechanism by which this occurs is called *adsorption*. In adsorption, molecules of gas become attached to the surface of organic material in shale. Nearly all the gas stored by adsorption exists in a condensed, near-liquid state. Adsorption can be visualized by imagining a magnet attached to a metal surface, or lint attached to a sweater. This is different from *absorption* where one substance becomes trapped inside another, such as a sponge soaking up water. Adsorption is a reversible process, because it involves weak attraction forces.

Typically, shale reservoirs can store far more gas in the adsorbed state than conventional reservoirs can hold by compression at pressures below 1000 psia. Since the volume of a cleat or fracture system is small when compared to the volume of the reservoir, free gas only accounts for a small portion of the gas stored in shale. As a result, the pressure volume relationship is often described by the desorption isotherm only.

Langmuir isotherm formulation

The release of adsorbed gas is commonly described by a pressure relationship called the Langmuir isotherm. The Langmuir adsorption isotherm assumes that the gas attaches to the surface of the shale, and covers the surface as a single layer of gas (a monolayer). At low pressures, this dense state allows greater volumes to be stored by sorption than is possible by compression.

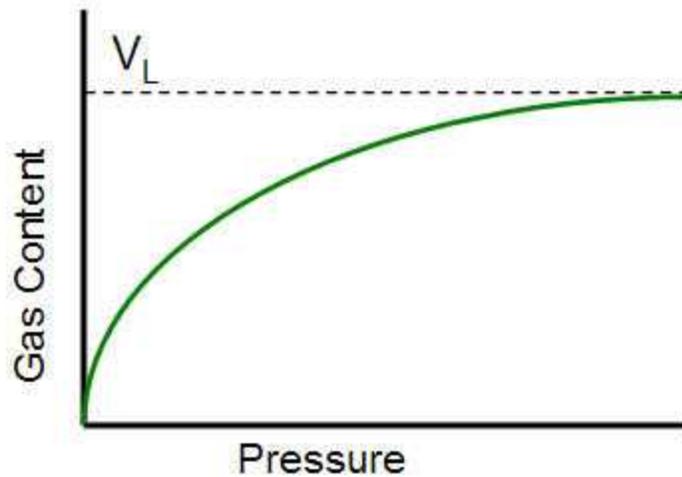
The typical formulation of the Langmuir isotherm is:

$$C_g = \frac{V_L p}{p_L + p}$$

where C_g is the gas content measured in scf / ton of shale.

Langmuir volume

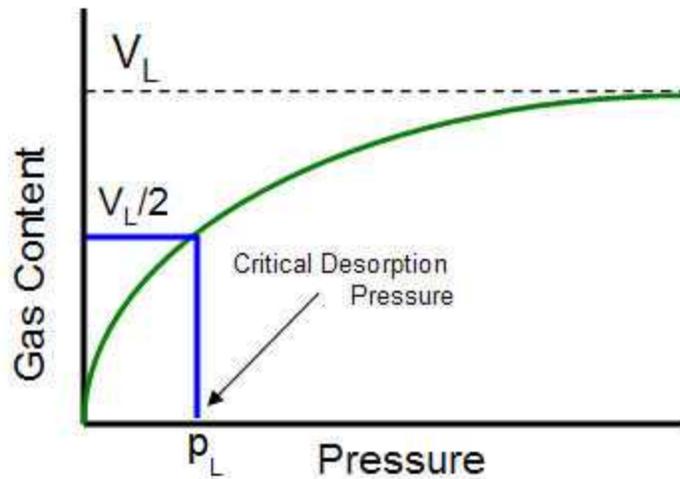
The Langmuir volume is the maximum amount of gas that can be adsorbed at infinite pressure. The following plot of a Langmuir isotherm demonstrates that gas content asymptotically approaches the Langmuir volume as pressure increases to infinity.



The units for Langmuir volume are scf / ton (volume gas per mass of shale). This can be converted to scf/ft³ (volume of gas per volume of shale) by multiplying it by the bulk density.

Langmuir pressure

The Langmuir pressure, or critical desorption pressure, is the pressure at which one half of the Langmuir volume can be adsorbed. As seen in the figure below, it changes the curvature of the line and thus affects the shape of the isotherm.



Isotherm variability

An isotherm is based on the assumption that the temperature is constant. The adsorption capacity decreases as temperature increases. When doing any analysis on shale, it is important to use the isotherm based on the reservoir temperature.

Material balance time theory

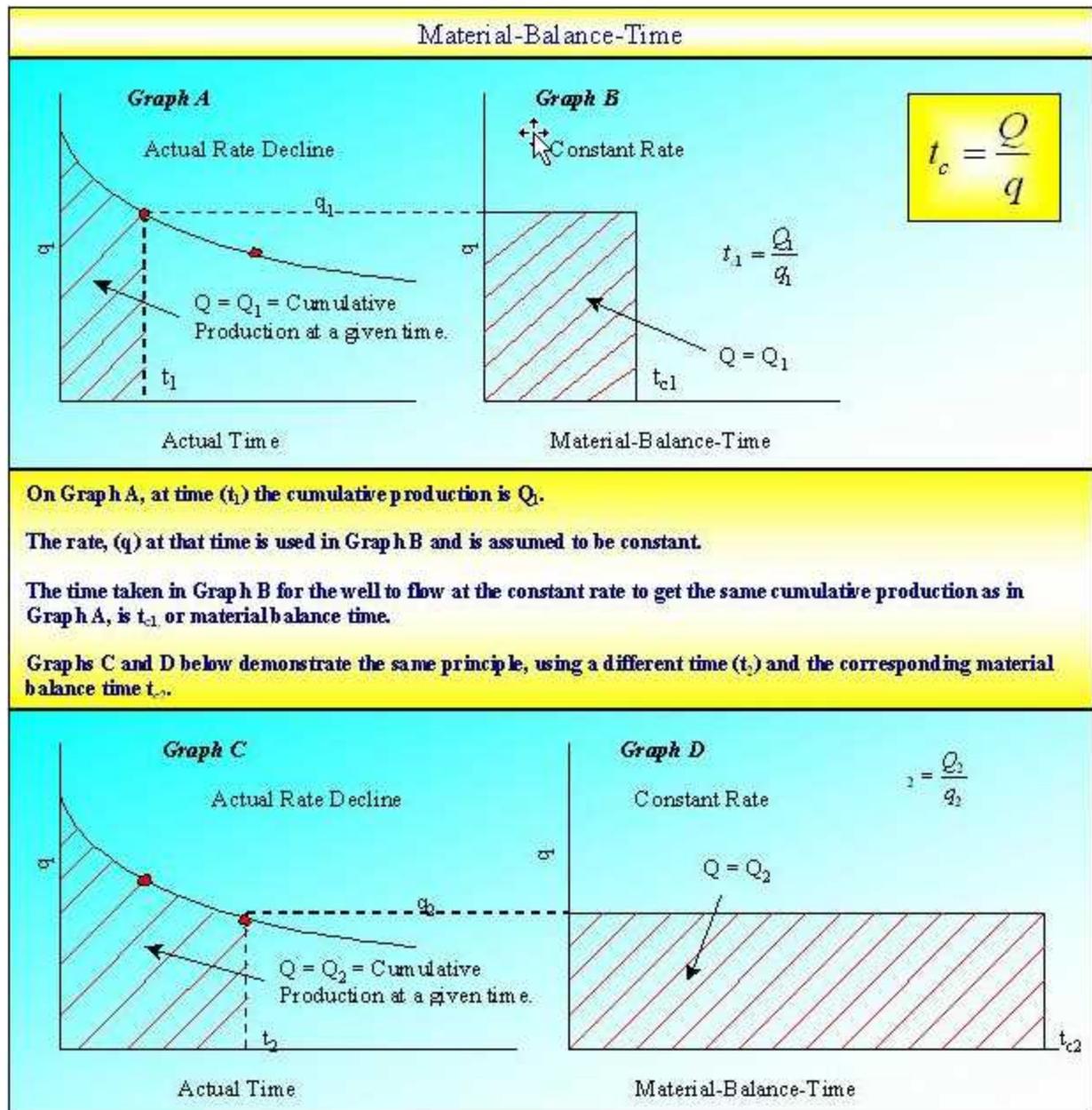
The Fetkovich typecurves are applicable to wells that produce at constant sandface pressure. Many wells, particularly gas wells, experience a decline in sandface pressure during their life. Blasingame and his students / co-workers (McCray, Palacio) developed a time function that enables the matching of production rate data on Fetkovich typecurves, even when the flowing pressure is varying. After developing different time functions, they came up with a simple function they called "material balance time" which works very well when the change in sandface pressure is smooth, as is often the case in production operations. They, and Agarwal-Gardner et al., also demonstrated that using material balance time converts the constant pressure solution into the constant rate solution, which is the solution widely used in the field of well testing.

Conceptually, material balance time is defined as the ratio of cumulative production to instantaneous rate:

$$t_c = \frac{Q}{q} \quad (1)$$

The symbol t_c has been adopted as it represents a corrected time based on cumulative production. It is also similar to the corrected "Horner" time that is used in build-up analysis in well

testing, for correcting the effect of a varying flow rate. It is the value of time that a well has to flow at the current rate in order to produce the same amount of fluid (and hence honor the material balance principle). In the figure below, the cumulative production is represented by the area under the graph. The definition of material balance time makes these areas the same.



On Graph A, at time (t_1) the cumulative production is Q_1 .

The rate, (q) at that time is used in Graph B and is assumed to be constant.

The time taken in Graph B for the well to flow at the constant rate to get the same cumulative production as in Graph A, is t_{c1} or material balance time.

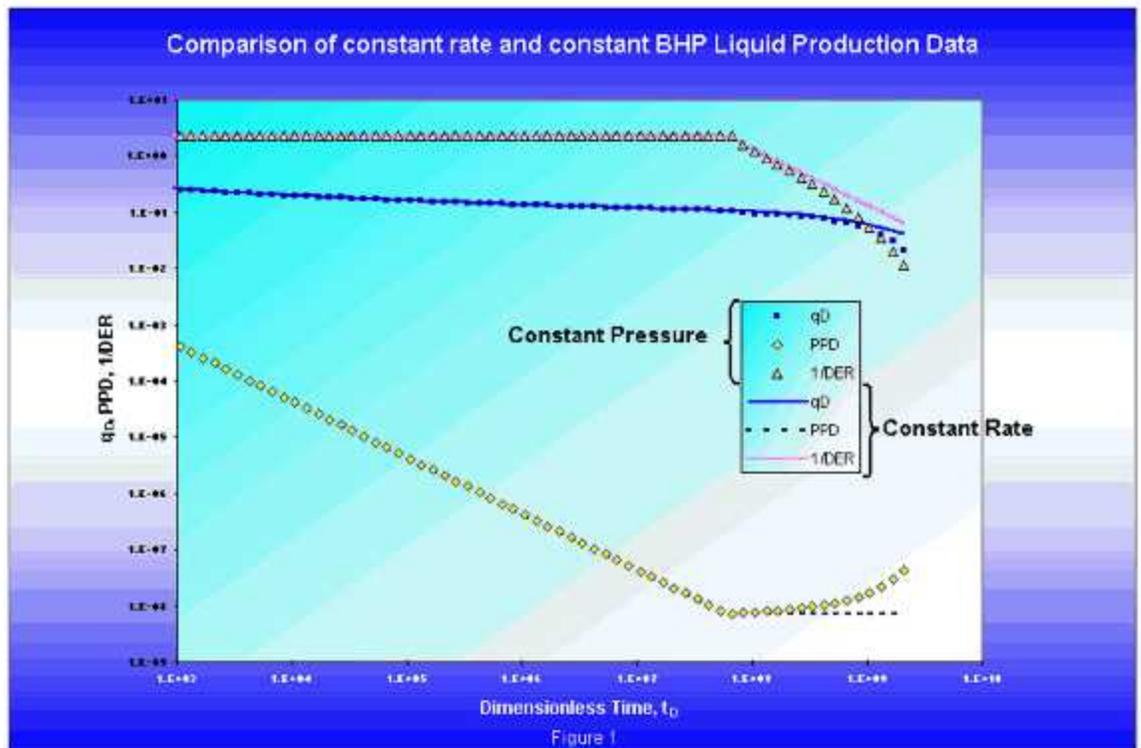
Graphs C and D below demonstrate the same principle, using a different time (t_2) and the corresponding material balance time t_{c2} .

Derivation of material balance time for slightly compressible systems focuses on the flow of liquids, and does not address the pseudo-time issues for gas reservoirs. It is fundamental to two basic ideas, namely the equivalence of constant pressure and constant rate solutions, and the

harmonic stem of decline curves. Material balance pseudo-time for gas accounts for changing pressure-volume-temperature (PVT) properties with reservoir pressure.

Constant compressibility fluids

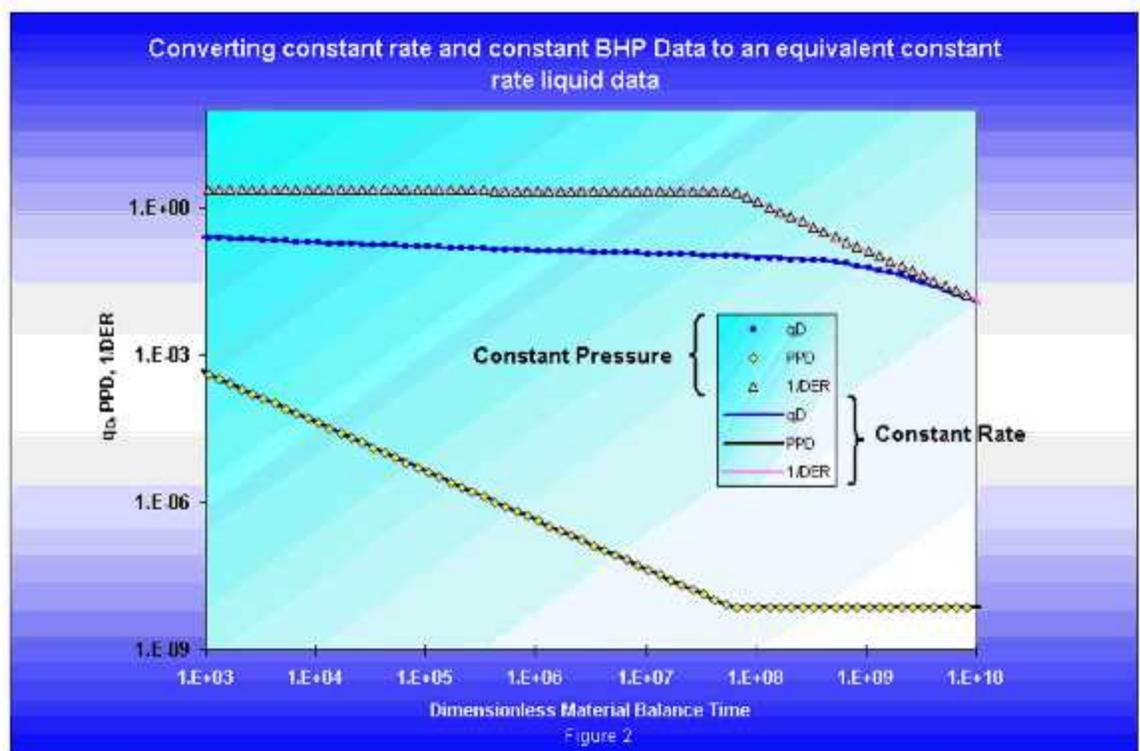
Consider an oil reservoir. A comparison of the constant rate (declining pressure) and constant pressure (declining rate) typecurves obtained when plotting against dimensionless time (based on area) shows the equivalence of the two solutions during the transient period, and their divergence during boundary-dominated flow.



Material balance time also normalizes production histories in which both the rate and the pressure decline, provided that both sets of data decline monotonically.

Another way to state the functionality of material balance time is to say that it is effective in normalizing any rate / pressure history, so that it looks like the constant rate solution, provided that the rate / pressure history does not contain any disturbances large enough to disrupt boundary-dominated flow. A disturbance that is large enough to disrupt boundary-dominated flow, such as a sudden (and significant) decrease in back pressure, would introduce a new transient flow period. Since material balance time is designed to normalize boundary-dominated flow only, it loses its effectiveness if a new transient is introduced.

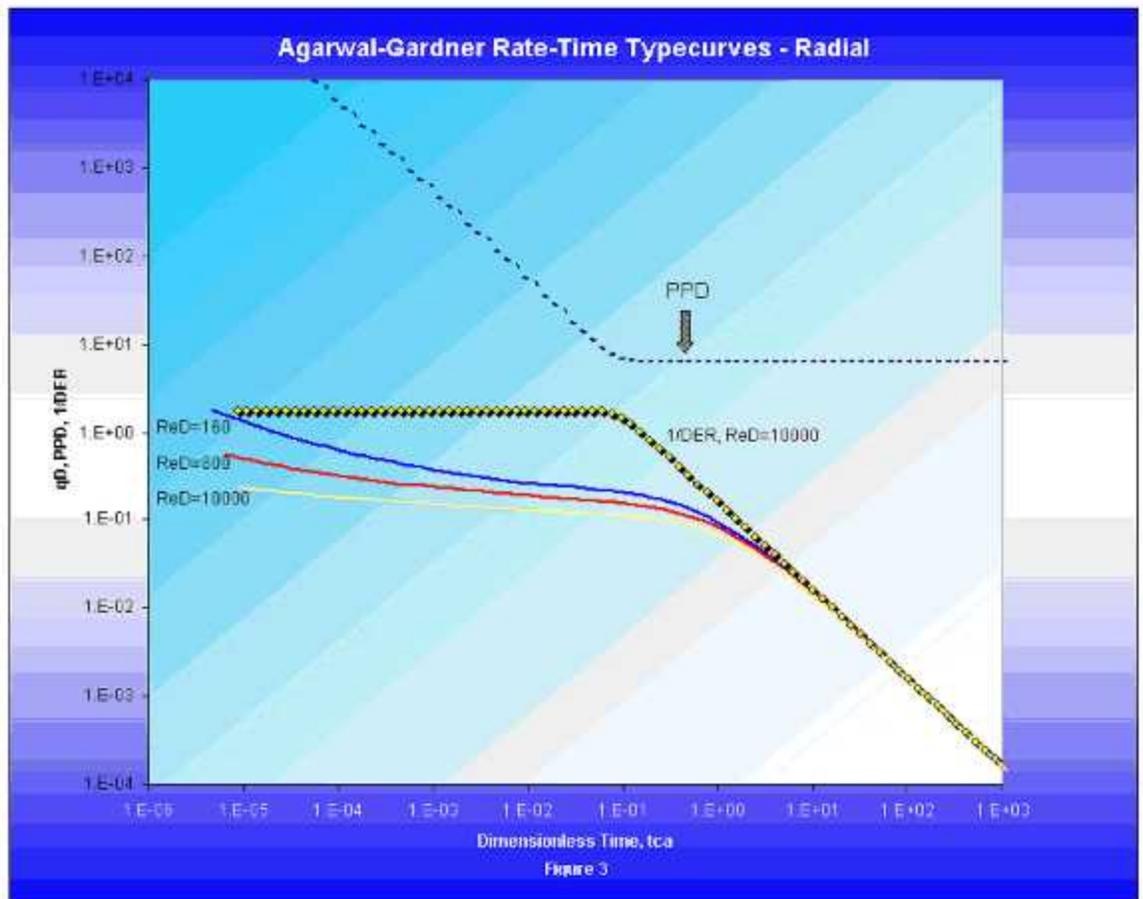
When the same typecurves (in figure 1) are plotted against dimensionless material balance time, the late time portion of the constant pressure overlays the constant rate solution precisely. This is an important result because it illustrates that the same diagnostic plots used in pressure transient analysis can be inverted and used for rate transient analysis, provided that the material balance time function is used.



From the above figure, it can be seen that the inverse logarithmic derivative behaves very similarly to the logarithmic derivative on a welltest typecurve. During transient (radial) flow, it has a constant value of 2 (1 divided by $\frac{1}{2}$). Upon reaching boundary-dominated flow, the inverse logarithmic derivative falls off with a constant slope of 1 on the log-log plot. The primary pressure derivative has the opposite behavior to the inverse log derivative, in that it exhibits a slope of negative 1 during transient flow, and becomes constant during boundary-dominated flow. This follows from the fact that the pressure decline for a well produced at a constant rate has a constant slope on log-log paper, during pseudo-steady state.

The $1/p_D$ (q_D) data, for different combinations of r_e / r_w , exhibit a fan of transient stems that converge into one harmonic depletion stem when plotted against dimensionless time based on area. If the data is plotted against a dimensionless time based on effective wellbore radius rather than reservoir area, the transient stems merge together while the depletion stems fan out.

The main difference in appearance between Agarwal-Gardner (A-G) typecurves and Fetkovich typecurves is that the depletion stems for A-G typecurves all collapse to the harmonic case. This follows from the fact that the A-G typecurve normalizes all rate and pressure solutions, so that they behave like the constant rate solution for slightly compressible fluids. Figure 3 shows the A-G typecurves for a vertical, unfractured well.



The presence of the inverse log derivative and pressure derivative plots on the A-G typecurve aids in the identification of transient and boundary- dominated flow regimes, in the same way that the logarithmic pressure derivative aids in flow regime identification on welltest typecurves.

Material balance time for oil

When analyzing oil wells:

$$t_c = \frac{N_p}{q_o} \quad (1a)$$

The following development (see Palacio and Blasingame, 1993) applies rigorously to a system with constant compressibility, such as an undersaturated oil reservoir.

Using the definition of compressibility, the oil production from a reservoir is related to the drop in average reservoir pressure, as follows:

$$c = -\frac{1}{V} \frac{\partial V}{\partial p}$$

$$c_t = \frac{5.615 (q B) dt}{A h \phi d\bar{p}} \quad (2)$$

Separating the variables and integrating:

$$\int_0^t q dt = -\frac{A h \phi c_t}{5.615 B_o} \int_{p_i}^{\bar{p}} d\bar{p} \quad (3)$$

Recognizing that the left side is the cumulative oil production, the average reservoir pressure can be calculated from:

$$\bar{p} = p_i - \frac{1}{N c_t} N_p \quad (3a)$$

The important characteristic of equation (3a) is that it is always valid — regardless of time, flow regime, or production scenario (constant or variable flow rate). This is because equation (3a) is a material balance equation.

Note that if p is plotted vs. N_p , then a straight line of slope $1/N c_t$ and intercept p_i is obtained. Of course, p is typically not available in practice, so we must use an alternate approach to applying this concept. Before doing so, we recast equation (3a) by including the definition of t_c , as in Equation (1a):

$$\frac{p_i - \bar{p}}{q} = \frac{1}{N c_t} t_c \quad (3b)$$

The second equation to be used is the steady-state solution for single-phase liquid flow in a rectangular reservoir containing a vertical well:

$$\frac{k h}{141.2 q B \mu} (\bar{p} - p_{wf}) = \frac{1}{2} \ln \left(\frac{4}{e^\gamma} \frac{A}{C_A r_w^2} \right) \quad (4)$$

where:

$$\gamma = \text{Euler's constant} = 0.57721$$

Although equation (4) was derived for constant rate (variable p_{wf}), Blasingame and Lee (1986) showed that it is also valid when the sandface pressure is constant (variable rate). Combining the material balance equation (3b) and the steady-state flow equation (4) gives:

$$\frac{p_i - p_{wf}}{q} = \frac{\Delta p}{q} = m t_c + b_{pss} \quad (5)$$

where:

$$m = \frac{1}{N c_i}$$

and:

$$b_{pss} = \frac{141.2 B \mu}{k h} \frac{1}{2} \ln \left(\frac{4}{e^\gamma} \frac{A}{C_A r_w^2} \right)$$

Equation (5), called the pseudo-steady state equation, suggests that a plot of $\Delta p / q$ as a function of material balance time yields a straight line. If we assume q is constant, then equation (5) reduces to:

$$\Delta p = m q t_c + q b_{pss}$$

and a plot of Δp vs t_c yields a straight line.

Blasingame and Lee state that the importance of equation (5) is that it is also valid for moderately changing flow rate and sandface pressure conditions, so long as the transients caused by the changing inner boundary condition do not obscure the boundary-dominated flow behavior. In

particular, equation (5) is directly related to two concepts: the equivalence of the constant pressure and constant rate solutions, and the harmonic stem of decline curves.

Material balance pseudo-time for gas

The application of material balance time to gas is more complex than it is for oil because of the varying PVT properties of gas. Accordingly, the simple concept of material balance time given by:

$$t_c = \frac{G_p}{q_g} \quad (1b)$$

has limited application, and is considered to be only an approximation of the more rigorous formulation, which must be defined in terms of pseudo-time, t_a . Material balance pseudo-time, t_{ca} , is defined as follows:

$$t_{ca} = \frac{(\mu_g c_g)_i}{q_g} \int_0^t \frac{q_g}{\bar{\mu}_g \bar{c}_g} dt \quad (6)$$

Equation (6) can be coupled with the steady-state flow equation for the flow of single-phase gas (which is the gas equivalent of equation (4) of this section), to give:

$$\frac{\bar{p}_p - p_{pwf}}{q} = \frac{1.417 * 10^6 T}{k h} \frac{1}{2} \ln \left(\frac{4}{e^\gamma} \frac{A}{C_A r_{wa}^2} \right) \quad (7)$$

where:

$$\gamma = \text{Euler's constant} = 0.57721$$

Addition of equations (6) and (7) results in the following equation:

$$\frac{\Delta p_p}{q} = m_a t_{ca} + b_{a,pss} \quad (8)$$

where:

$$m_a = \frac{2 p_i}{(\mu c_t Z)_i G}$$

and:

$$b_{a,pss} = \frac{1.417 * 10^6 T}{k h} \frac{1}{2} \ln \frac{4}{e^\gamma} \frac{A}{C_A r_{wa}^2}$$

Total compressibility

The definition of material balance pseudo-time described in equation (6) accounts only for the compressibility of gas. This is often a reasonable approximation as gas compressibility is typically much larger than that of liquid or rock. However, in some cases, the compressibilities of other fluids cannot be ignored. Thus, we require a more general definition of pseudo-time that accounts for the total system compressibility. Total compressibility includes gas compressibility, as well as water influx and production, formation and residual fluids compressibilities, and gas desorption.

$$t_{ca} = \frac{(\mu_g c_t)_i}{q_g} \int_0^t \frac{q_g}{\bar{\mu}_g \bar{c}_t} dt \quad (6)$$

The following is a derivation for total compressibility in a general form.

Material balance equation

Refer to [material balance analysis theory - gas material balance](#) for the general gas material balance equation. The general gas material balance equation can be expanded to include water influx and production, formation and residual fluids compressibilities, and desorption of gas (ΔV_{wip} , ΔV_{ep} and ΔV_d , respectively) as follows:

$$G_f B_{gi} = (G_f - G_p) B_g + \Delta V_{wip} + \Delta V_{ep} + \Delta V_d \quad (9)$$

where:

$$\Delta V_{wip} = 5.615 (W_e - W_p B_w)$$

$$\Delta V_{ep} = \frac{B_{gi} G_f}{S_{gi}} \left[\left(1 - e^{-\int_{p_i}^{p_L} c_f dp} \right) + S_{wi} \left(e^{\int_{p_i}^{p_L} c_w dp} - 1 \right) + S_{oi} \left(e^{\int_{p_i}^{p_L} c_o dp} - 1 \right) \right]$$

$$\Delta V_d = \rho_B B_g \frac{B_{gi} G_f}{S_{gi} \phi} \left(\frac{V_L p_i}{p_L + p_i} - \frac{V_L p}{p_L + p} \right)$$

The relative change of the pore volume due to water influx and production, formation and residual fluid expansion, and desorption of gas (c_{wip} , c_{ep} , and c_d , respectively), can then be defined as:

$$c_{wip} = \frac{\Delta V_{wip}}{B_{gi} G_f / S_{gi}} = \frac{5.615 (W_e - W_p B_w)}{B_{gi} G_f / S_{gi}}$$

$$c_{ep} = \frac{\Delta V_{ep}}{B_{gi} G_f / S_{gi}} = \left(1 - e^{-\int_{p_i}^p c_f dp}\right) + S_{wi} \left(e^{\int_{p_i}^p c_w dp} - 1\right) + S_{oi} \left(e^{\int_{p_i}^p c_o dp} - 1\right)$$

$$c_d = \frac{\Delta V_d}{B_{gi} G_f / S_{gi}} = \frac{\rho_B B_g}{\phi} \left(\frac{V_L p_i}{p_L + p_i} - \frac{V_L p}{p_L + p} \right)$$

If the adsorption saturation correction has been enabled, c_d is modified as follows:

$$c_d' = \frac{\rho_b \left(B_g - \frac{1.38 \times 10^{-6} M}{\rho_b} \right)}{\phi} \left[\frac{V_L p_i}{p_i + p_L} - \frac{V_L p}{p + p_L} \right]$$

For more information, see material balance analysis theory - advanced gas material balance.

Solving for total compressibility (c_t)

The solution for total compressibility comes from the definition of pseudo-time:

$$t_a = \int_0^t \frac{k_r dt}{\mu c_t}$$

By taking the partial derivative of pseudo-time with respect to time, total compressibility is exposed:

$$\frac{\partial t_a}{\partial t} = \frac{k_r}{\mu c_t} \quad (10)$$

The following chain rule of derivatives is applied:

$$\frac{\partial t_a}{\partial t} = \frac{\partial t_a}{\partial p_p} \frac{\partial p_p}{\partial p} \frac{\partial p}{\partial t}$$

Therefore, equation (10) may be expressed as:

$$\frac{k_r}{\mu c_t} = \frac{\partial t_a}{\partial p_p} \frac{\partial p_p}{\partial p} \frac{\partial p}{\partial t} \quad (11)$$

Note that the inclusion of a permeability term in the above definition of pseudo-time accounts for a pressure-dependent permeability. For more information on theory and equations, see [geo-mechanical reservoir models](#).

Solving for $\partial t_a / \partial p_p$

Defining pseudo-pressure:

$$p_p = 2 \int_{p_o}^p \left(\frac{k_r p}{\mu Z} \right) dp$$

Relating pseudo-pressure to pseudo-time (Rahman et al., 2006):

$$\frac{\partial p_p}{\partial t_a} = \frac{-2 k_r q p_i S_{gi}}{Z_i G_f}$$

$$\frac{\partial t_a}{\partial p_p} = \frac{Z_i G_f}{-2 k_r q p_i S_{gi}} \quad (12)$$

Solving for $\partial p_p / \partial p$

From the above definition of pseudo-pressure:

$$\frac{\partial p_p}{\partial p} = \frac{2 k_r p}{\mu Z} \quad (13)$$

Solving for $\partial p / \partial t$

Dividing both sides of equation (9) by $(G_f B_{gi} / S_{gi})$ and recalling that $B_g = (p_{sc} Z T) / (T_{sc} P)$:

$$\frac{p}{Z} (S_{gi} - c_{wip} - c_{ep} - c_d) = \frac{p_i}{Z_i} \left(\frac{G_f - G_p}{G_f} \right) S_{gi}$$

Letting c equal the summation of c_{wip} , c_{ep} , and c_d ; and rearranging:

$$\frac{p}{Z} = \frac{p_i S_{gi}}{Z_i G_f} \left(\frac{G_f - G_p}{S_{gi} - c} \right) \quad (14)$$

$$\frac{\partial p}{\partial t} \frac{p}{Z} = \frac{\partial}{\partial t} \frac{p_i S_{gi}}{Z_i G_f} \left(\frac{G_f - G_p}{S_{gi} - c} \right)$$

$$\frac{\partial p}{\partial p} \frac{p}{Z} \frac{\partial p}{\partial t} = \frac{p_i S_{gi}}{Z_i G_f} \frac{\partial}{\partial t} \left((G_f - G_p)(S_{gi} - c)^{-1} \right)$$

Where: $\frac{\partial}{\partial t} G_p = q$, $\frac{\partial}{\partial t} c = \frac{\partial c}{\partial p} \frac{\partial p}{\partial t}$, $c_g = \frac{1}{p} - \frac{1}{Z} \frac{\partial Z}{\partial p}$

$$\frac{p}{Z} \left(\frac{1}{p} - \frac{1}{Z} \frac{\partial Z}{\partial p} \right) \frac{\partial p}{\partial t} = \frac{p_i S_{gi}}{Z_i G_f} \left[\frac{-q}{(S_{gi} - c)} - \frac{(G_f - G_p) \left(-\frac{\partial c}{\partial p} \frac{\partial p}{\partial t} \right)}{(S_{gi} - c)^2} \right]$$

$$\frac{p}{Z} c_g \frac{\partial p}{\partial t} = \frac{p_i S_{gi}}{Z_i G_f} \left[\frac{-q}{(S_{gi} - c)} - \frac{(G_f - G_p) \left(-\frac{\partial c}{\partial p} \frac{\partial p}{\partial t} \right)}{(S_{gi} - c)^2} \right] \quad (15)$$

Rearranging equation (14) such that:

$$\frac{p Z_i G_f}{Z p_i S_{gi}} = \left(\frac{G_f - G_p}{S_{gi} - c} \right)$$

Equation (15) can now be written as:

$$\frac{p Z_i G_f}{Z p_i S_{gi}} \left(c_g - \frac{\frac{\partial c}{\partial p}}{(S_{gi} - c)} \right) \frac{\partial p}{\partial t} = \frac{-q}{(S_{gi} - c)}$$

And then solved for $\partial p / \partial t$:

$$\frac{\partial p}{\partial t} = \frac{-q Z p_i S_{gi}}{p Z_i G_f} \frac{1}{c_g(S_{gi} - c) - \frac{\partial c}{\partial p}} \quad (16)$$

Substitution

Equations (12), (13), and (16) are substituted into the chain rule of derivatives from equation (11) and simplified:

$$\frac{k_r}{\mu c_t} = \frac{1}{\mu \left(c_g(S_{gi} - c) - \frac{\partial c}{\partial p} \right)}$$

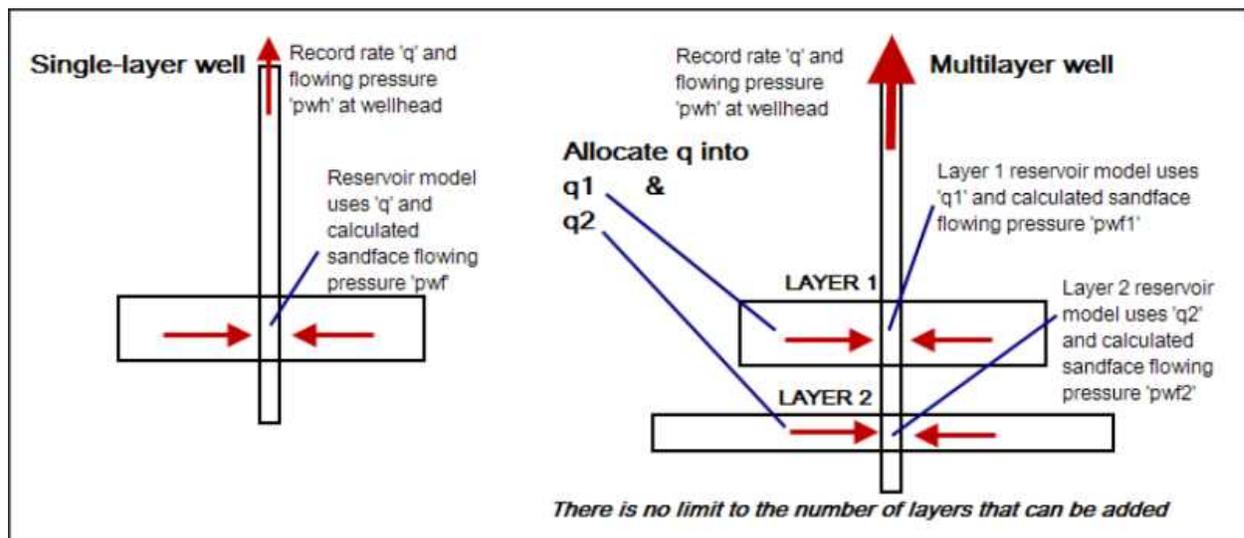
$$c_t = k_r \left(c_g(S_{gi} - c) - \frac{\partial c}{\partial p} \right)$$

As c equals the summation of c_{wip} , c_{ep} , and c_d :

$$c_t = k_r \left(c_g(S_{gi} - c_{wip} - c_{ep} - c_d) - \frac{\partial c_{wip}}{\partial p} - \frac{\partial c_{ep}}{\partial p} - \frac{\partial c_d}{\partial p} \right)$$

Multilayered wells

Many wells produce from a single layer (formation) economically, but occasionally a well is drilled that intersects and combines (commingles) the flows of two or more layers. Such a well is called a multilayer well or a commingled well. For these wells, the reservoir dynamics may not be sufficiently modeled using just one set of reservoir properties, or just one analytical / numerical model. Consequently, one approach is to analyze the well on a layer-by-layer basis, with the advantage of more accurately matching the reservoir dynamics than can be done with a typical single-layer modeling approach.

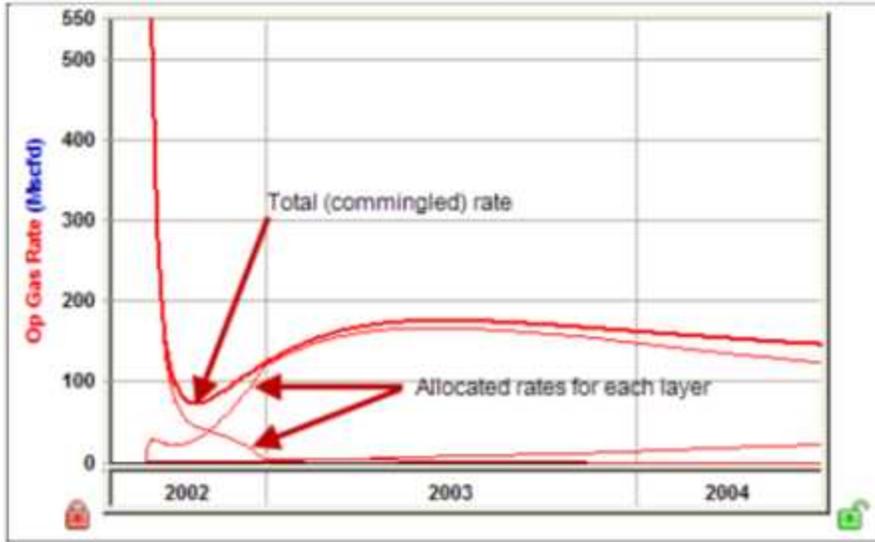


Multilayer well analysis and its advantages

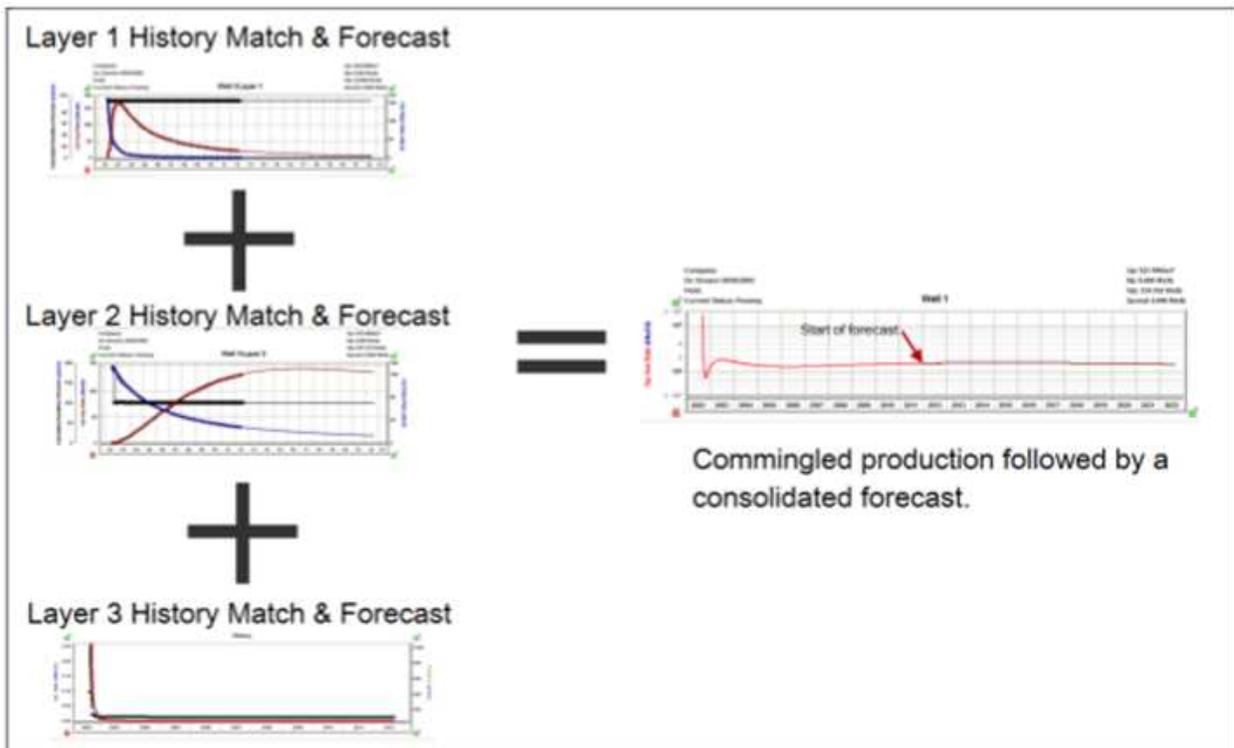
To model the flow dynamics of a layer, we need its rates and its sandface flowing pressures through time. However, measured data usually consists of the total commingled rates and the wellhead flowing pressures. Therefore, the first step is to import the rates and pressures for the well.

To get the rates and flowing pressures for each layer, we need to allocate the rates down to each layer. This is typically done by running a production logging tool (PLT) such as a spinner, or a fiber-optic-based distributed temperature sensor (DTS). Allocation measurements are made at points in time, and can be entered into Harmony Enterprise.

After the rates at each layer have been calculated using the allocation measurements, the wellbore converts the wellhead flowing pressure to the sandface flowing pressures for each layer. By having rates and flowing pressures for each layer, we have effectively divided our multilayer well into a set of single-layer wells all feeding into one wellbore.



Individual layer forecasts and their consolidated forecast



Oil PVT change during reservoir depletion (analytical models)

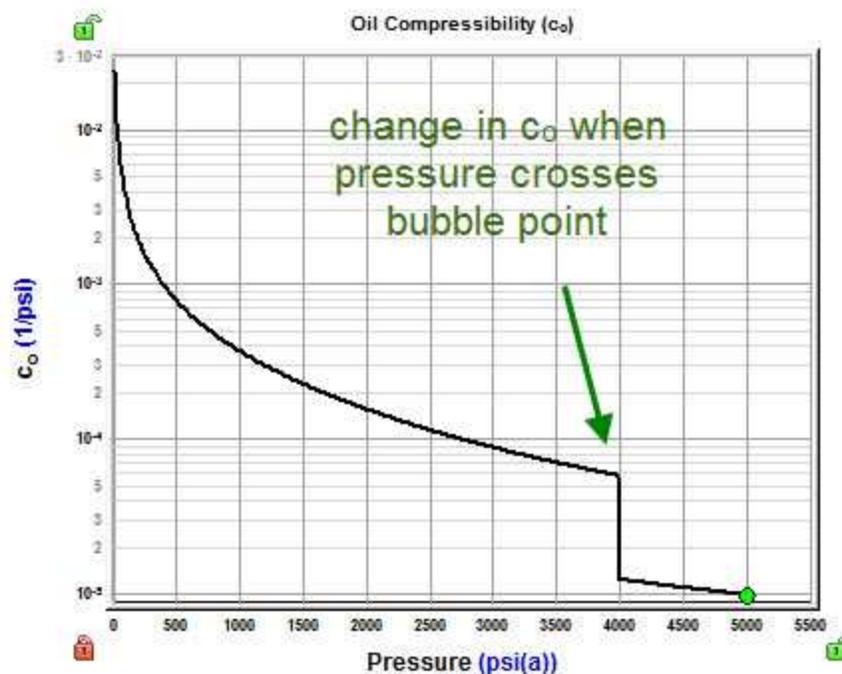
Fluid properties (such as compressibility, viscosity etc.) depend on pressure; therefore, while a reservoir is being depleted, fluid properties change.

For gas analytical models, pseudo-pressure and pseudo-time are used to account for the change in gas properties.

For oil analytical models, fluid properties are assumed to be constant: properties are estimated at the initial pressure using correlations or tables set in the Properties editor, and these properties are used for calculations throughout the production history and the forecast.

$$\begin{array}{l} B_{oi} = B_o(p_i) \\ c_{oi} = c_o(p_i) \\ \mu_{oi} = \mu_o(p_i) \end{array} \quad \left. \vphantom{\begin{array}{l} B_{oi} = B_o(p_i) \\ c_{oi} = c_o(p_i) \\ \mu_{oi} = \mu_o(p_i) \end{array}} \right\} \text{ used for calculations}$$

This assumption is acceptable if the pressure in the reservoir remains above the bubble point, since the variations for under-saturated oil properties with pressure are negligible. However, if the pressure drops below the bubble point, oil properties (in particular – oil compressibility) change significantly.



As a result, numerical models are recommended for forecasting in under-saturated oil reservoirs, or for history matching in saturated oil reservoirs. However, analytical models can be used to history match a brief portion of data, such as a buildup, in saturated oil reservoirs because the properties aren't changing significantly during the segment being analyzed. Although oil analytical models do not honor varying oil properties, it is possible to use (constant) oil properties corresponding to the depleted reservoir conditions.

Example: Consider an under-saturated oil reservoir with: $p_i = 5000$ psi and $p_{bp} = 4500$ psi.

The well was producing at a constant rate (drawdown) and then was shut in (buildup). During the drawdown, reservoir pressure dropped to 4,400 psi; therefore, during the buildup, the reservoir was filled with saturated oil. As a result, saturated oil properties should be used to history match the buildup.

To do this in an analytical model:

1. Select the **PVT Pressure** option in the Analytical Model pane.
2. Expand the **PVT Pressure** group and set p_{prop} to 4,400 psi.



In this case, the properties used for calculations are evaluated at p_{prop} .

$$\left. \begin{aligned} B_o &= B_o(p_{prop}) \\ c_o &= c_o(p_{prop}) \\ \mu_o &= \mu_o(p_{prop}) \end{aligned} \right\} \text{ used for calculations}$$

Note: With this approach, the drawdown portion of the data is not matched. However, matching just the buildup portion of the data is useful, as it helps to estimate current reservoir and completion properties.

Probabilistic

The probabilistic analysis is designed to address uncertainty in well performance in the following areas:

- Expected performance and recovery in new wells (that is, proven, and undeveloped locations)
- True numerical probabilistic forecasting for wells with established production history

The probabilistic module uses Monte Carlo simulation to generate stochastic outputs for reservoir parameters such as OFIP, EUR, linear flow parameters (when applicable), and the production forecast. The model can be constrained to a known well history using automatic parameter estimation, which optimizes key input parameters to ensure there is a minimum level of conformance with production history. Dependencies between input parameters can be specified using a correlation matrix. Results are displayed with histograms and shaded plots of statistical outputs.

Pseudo-pressure (ψ)

Pseudo-pressure is a mathematical pressure function that accounts for the variable compressibility and viscosity of gas viscosity (μ_g) with respect to pressure.

Note: If there is geomechanical reservoir behavior, see the [modification for geomechanical models](#).

The equation for the flow of gas in the reservoir is very similar to that for liquid flow. In well testing and rate transient analysis, analytical equations are solved after making certain assumptions. In particular, five assumptions are very important.

1. Total system compressibility (c_t) is constant
2. Fluid density ($\rho \propto p / Z$) is constant
3. Fluid viscosity (μ) is constant
4. Total porosity (ϕ) is constant
5. Fluid saturations are constant

For liquids, these assumptions are reasonable because liquid compressibility, density, and viscosity do not vary significantly with pressure, and the equations can be solved analytically. These analytical solutions are referred to as the liquid-flow solutions, and form the basis of all well test and rate transient analysis. The result is an analytical relationship between pressure and time. Liquid-flow solutions for different wellbore and reservoir configurations are available in the literature. For example, for the case of an infinite-acting reservoir and a vertical well producing at a constant rate, pressure can be calculated as:

$$\text{Pressure} \approx \text{Constant} * \log(\text{time})$$

For gas, most of the assumptions listed above are no longer valid because gas density ($\rho \propto p / Z$) can vary significantly with pressure. Gas viscosity (μ_g) also varies with pressure, but not to the same degree. To deal with these changing gas properties, the concept of pseudo-pressure (ψ) was developed by Al-Hussainy et al. (1966) and is defined as follows:

$$\psi(p) = 2 \int_0^p \frac{p}{\mu Z} dp$$

This transformation of pressure to pseudo-pressure is an exact transformation, which accounts for variation of gas density and viscosity. If we assume that changes of total compressibility (c_t), porosity, and fluid saturations are insignificant, the gas flow equation can be written in a manner similar to the liquid equation. Therefore, the liquid-flow solution can be used for gas well test analysis and rate transient analysis provided pressure is replaced by pseudo-pressure. For the above mentioned example, pseudo-pressure can be calculated as:

$$\text{Pseudo-Pressure} \approx \text{Constant} * \log(\text{time})$$

Modification for geomechanical models

If there is geomechanical reservoir behavior, where rock permeability is changing with pressure, you can account for this behavior in the pseudo-pressure.

Changing permeability can be expressed as $k_{effective}(p) = k \cdot k_m(p)$ where k is the permeability at the initial pressure, and $k_m(p)$ is a (dimensionless) permeability multiplier.

To incorporate a variation of permeability with pressure into the pseudo-pressure term, the definition of pseudo-pressure is modified as follows:

$$\psi(p) = 2 \int_0^p \frac{p \cdot k_m(p)}{\mu Z} dp$$

Note: In some sources, pseudo-pressure is also referred to as the real gas potential ($m(p)$).

Pseudo-time

Pseudo-time is a mathematical time function that accounts for the variable total compressibility (c_t) and viscosity (μ_g) of gas, as well as the variable porosity (ϕ) with respect to time and pressure.

The equation for flow of gas in the reservoir is very similar to that for liquid flow. In well testing and rate transient analysis, analytical equations are solved after making certain assumptions. In particular, five assumptions are very important.

1. Total system compressibility (c_t) is constant
2. Fluid density ($\rho \propto p/Z$) is constant
3. Fluid viscosity (μ) is constant
4. Total porosity (ϕ) is constant
5. Fluid saturations are constant

For liquids, these assumptions are reasonable, since liquid compressibility and viscosity do not vary significantly with pressure, and the equations can be solved analytically. These analytical solutions are referred to as the liquid flow solutions, and form the basis of all well test and rate transient analysis. The result is an analytical relationship between pressure and time. For example, for the case of an infinite-acting reservoir and a vertical well producing at a constant rate, pressure can be calculated as:

$$\text{Pressure} \approx \text{Constant} * \log(\text{time})$$

For gas, most of the assumptions listed above are no longer valid, since gas density ($\rho \propto p/Z$), viscosity (μ_g) and total compressibility (c_t) can vary significantly with pressure. Pseudo-pressure (ψ) and pseudo-time (t_a) are used to deal with these changing properties and linearize the flow

equations for gas. With the introduction of pseudo-pressure and pseudo-time, the gas flow equation can be written in a manner similar to the liquid equation. Therefore, the liquid flow solution can be used for gas well test analysis and forecasting provided pressure is replaced by pseudo-pressure, and time is replaced by pseudo-time. For the above mentioned example, pseudo-pressure can be calculated as:

$$\text{Pseudo-pressure} \approx \text{Constant} * \log(\text{pseudo-time})$$

Development of pseudo-time

It should be noted that the concept of pseudo-time is not amenable to a completely rigorous solution, as is the case for pseudo-pressure, because the gas properties change with pressure, not time.

Pseudo-time was developed by Agarwal (1980) and he defined pseudo-time in terms of the viscosity (μ_g) and compressibility (c_t) at the wellbore (see [buildup pseudo-time](#)). This definition accounted for the large change in total compressibility (c_t) that occurs at low pressures (early time in a buildup). It had little effect on late time data, and was generally used for buildups only.

In the 90s, when the gas flow equations were being used for analyzing or forecasting data affected by reservoir depletion, it was realized that the Agarwal definition of pseudo-time for buildups, was inappropriate for boundary dominated flow (depleting systems). Palacio and Blasingame (1993) introduced a new definition of pseudo-time to account for the depletion effects. Instead of defining the pseudo-time transformation in terms of wellbore conditions like Agarwal did, they defined it in terms of the average reservoir pressure (see [drawdown pseudo-time](#)). This pseudo-time is appropriate for boundary dominated flow.

Anderson and Mattar (2005) found that, in a reservoir with significant transient flow, it was more appropriate to define pseudo-time in terms of the average pressure within the region of investigation rather than the average reservoir pressure (see [corrected pseudo-time](#)).

Different pseudo-time formulations are needed for buildup, for drawdown in a boundary dominated flow regime, and for a transient flow regime. The equations look similar, but they are radically different from each other.

Buildup pseudo-time

Pseudo-time for use in buildup analysis is defined in terms of pressure at the wellbore:

$$t_a(t) = (\mu_g c_t)_i \int_0^t \frac{dt}{\mu_g(p_{wb})c_t(p_{wb})}$$

If the wellbore has significant storage, a difference in the early time behavior will be noted, since pressure and thus compressibility and viscosity are changing most near the wellbore. Late time behavior is not typically affected by buildup pseudo-time since the pressure, viscosity, and compressibility become constant at the wellbore and in the reservoir.

Drawdown pseudo-time

Pseudo-time for use in drawdown analysis is defined in terms of average reservoir pressure:

$$t_a(t) = (\mu_g c_t)_i \int_0^t \frac{dt}{\mu_g(\bar{p})c_t(\bar{p})}$$

Note that the gas in place (GIP) must be known in order to perform the material balance calculations necessary to determine the average reservoir pressure.

Corrected pseudo-time

In the conventional definition of pseudo-time, the compressibility and viscosity terms are evaluated at average reservoir pressure conditions. Clearly, the average reservoir pressure is only a function of Original-Gas-In-Place (OGIP) and cumulative production. During the transient flow period, before any boundary effects are observed, the flow behavior of two different-sized reservoirs should be similar, and independent of the OGIP – they are both infinite-acting reservoirs. However using the conventional definition of pseudo-time, the result would be that the producing rates would be different because their average reservoir pressures are different due to the different OGIPs.

If a well is producing under boundary-dominated conditions, the average reservoir pressure is a very reasonable datum at which to establish fluid properties such as c_g . However, if the well production is still in transient flow and no reservoir boundaries have been observed, the average reservoir pressure based on total reservoir volume is not an appropriate datum to use. Consequently, pseudo-time can cause anomalous model responses under certain conditions.

Anderson and Mattar (2005) proposed that the average reservoir pressure used in the pseudo-time calculation during the transient flow period should be calculated based on the gas-in-place of the investigated volume at that time.

$$t_a(t) = (\mu_g c_t)_i \int_0^t \frac{dt}{\mu_g(p_{ir})c_t(p_{ir})}$$

This way, during transient flow, pseudo-time is independent of OGIP. As soon as the reservoir enters boundary-dominated flow, the conventional definition of pseudo-time is automatically resumed, because at that time the region of investigation is the whole reservoir.

The volume of investigation is calculated based on the radius of investigation formula:

$$r_{inv} = \sqrt{\frac{kt}{948 \cdot \phi \mu c_t}}$$

This volume is adjusted for the effect of the reservoir boundaries and the coalescence of regions of influence caused by interference between wells.

Modification for geomechanical models

If there is geomechanical reservoir behavior, where rock permeability and formation compressibility are changing with pressure, you can account for this behavior in the pseudo-time.

Changing permeability can be expressed as $k_{effective}(p) = k \cdot k_m(p)$ where k is the permeability at the initial pressure, and $k_m(p)$ is a (dimensionless) permeability multiplier.

To incorporate a variation of permeability with pressure into the pseudo-time term, the definition of pseudo-time is modified as follows:

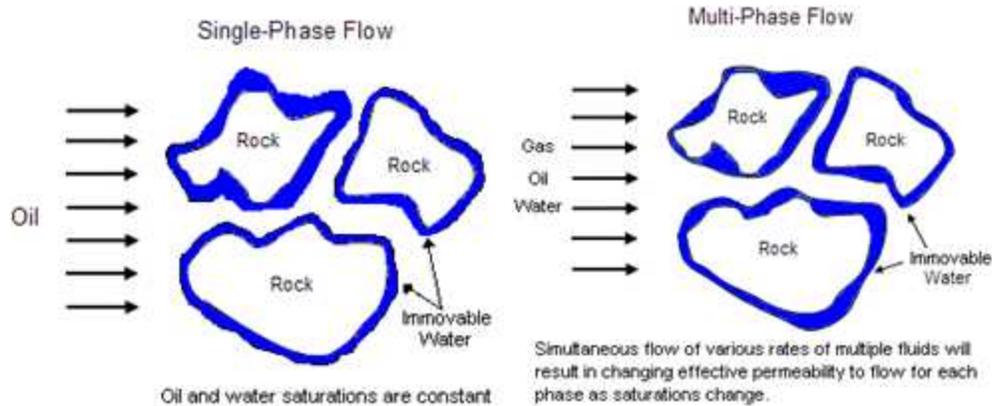
$$t_a(t) = (\mu_g c_t)_i \int_0^t \frac{k_m(\bar{p}) dt}{\mu_g(\bar{p}) c_t(\bar{p})}$$

Note: Variation of the formation compressibility with pressure is incorporated in the $c_t(p)$ term.

Relative permeability

Relative permeability is a concept used to convey the reduction in flow capability due to the presence of multiple mobile fluids. It is dependent upon pore geometry, wettability, fluid distribution, and the fluid saturation history. Relative permeability measurements are conducted on core samples in a laboratory, and are both time-consuming and expensive to produce. Consequently, relative permeability measurements are most often requested for projects where secondary and/or tertiary recovery is being considered.

In a single-phase system such as a dry-gas or an under-saturated oil reservoir, the effective permeability of flow of the mobile fluid through the reservoir varies little during production because the fluid saturations do not change. However, when more than one phase is mobile, the effective permeability to each mobile phase will change as the saturations of the fluids change in the reservoir.



In a two-phase system, the fluids might consist of oil and water, or oil and gas. In a three-phase system, all three fluid phases occur. Each fluid, as it flows through the porous media, interferes with the fluids because capillary forces exist that reduce the flow rate of each individual phase in a non-linear fashion. Consequently, the sum of the relative permeabilities of each phase is always less than one.

$$k_{ro} + k_{rw} + k_{rg} < 1$$

Relative permeability terms and equations

Typical phases in a reservoir are oil, water, and gas; and the effective permeability of each is designated as k_o , k_w , and k_g , respectively. The relative permeability for each phase is calculated by dividing the effective permeability to flow by the absolute permeability. The absolute permeability is the “Klinkenberg” or theoretical “air” permeability, which is measured by cleaning and completely drying a core sample, and then measuring the effective permeability of flow to air. The units of relative permeability are dimensionless.

$$k_{ro} = \frac{k_o}{k}, k_{rw} = \frac{k_w}{k}, k_{rg} = \frac{k_g}{k}$$

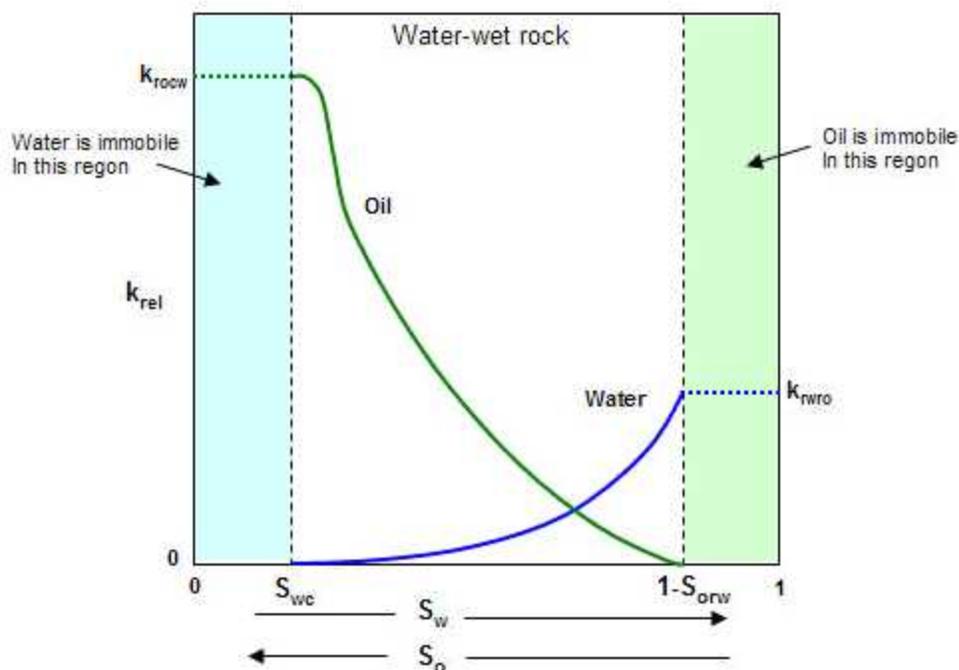
Wettability

Wettability in a reservoir is a measurement of the ability of a fluid to coat the rock surface. Wettability and heterogeneity have a significant impact on the shape of the relative permeability curves. The wetting fluid relative permeability curve is concave upwards, whereas the non-wetting fluid has an “s” shape. In the case where there is no interfacial tension between the fluid phases, the relative permeability curves simplify to straight lines between the endpoints.

Water-wet relative permeability curves (oil and water)

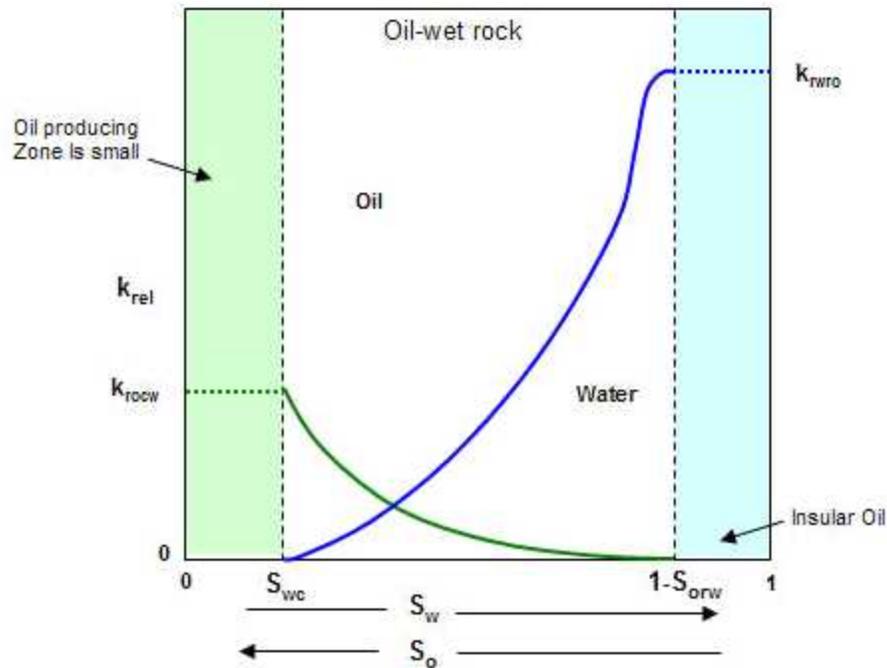
A schematic of oil-water relative permeability curves in a water-wet reservoir is shown below. In water-wet rock, a water layer wets the rock surface and acts like a lubricant for the oil located in the central parts of the pores.

- S_{wc} is the connate or irreducible water saturation. This is the water saturation below which water is not mobile because of capillary forces. The relative permeability of water at water saturations below S_{wc} is zero.
- S_{orw} is the residual oil saturation or critical oil saturation. This is the oil saturation below which the oil is immobile, that is, its relative permeability is zero.



Oil-wet relative permeability curves (oil and water)

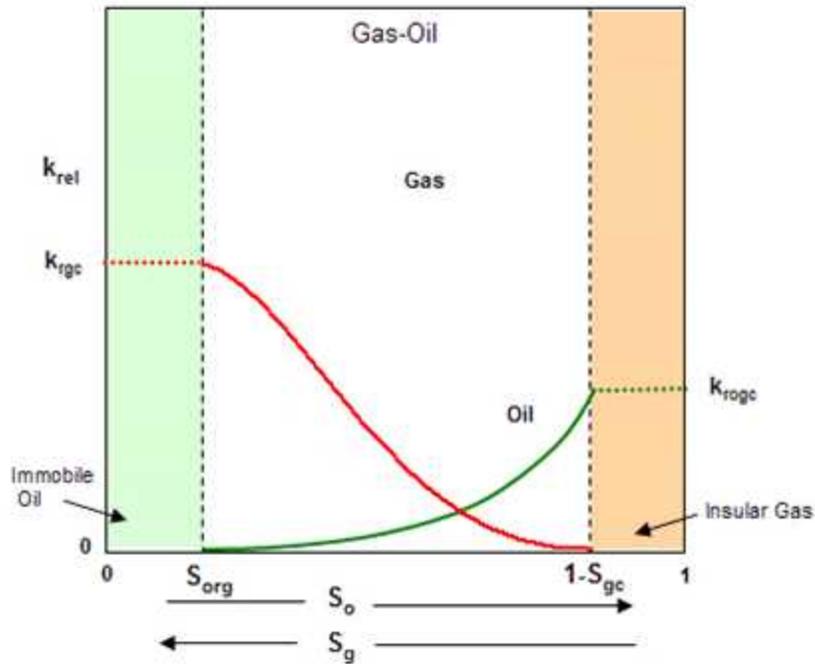
The figure below displays a schematic of water-oil relative permeability curves in an oil-wet reservoir rock. In oil-wet rock, oil wets the pore surfaces and water occupies the central regions of the pores. Typically, the irreducible water saturation in oil-wet reservoir rock is lower than that in water-wet rock.



Gas-oil relative permeability curves

The schematic below displays a set of gas-oil relative permeability curves. In this case, the wetting phase (the oil phase) impedes the flow of gas. The water saturation in the reservoir rock is taken to not exceed its irreducible value. This means that the water is not mobile, but exists in the pore space and simply reduces the available pore space that the gas and oil can occupy.

- S_{gc} is the critical gas saturation. This is the minimum saturation for gas to become mobile.
- S_{org} is the residual oil saturation to gas. This is the immobile oil when gas is the displacing fluid.
- k_{rogc} is the relative permeability of oil at the critical gas saturation.
- k_{rgc} is the relative permeability of the gas at the residual oil saturation.



Normalized relative permeability

When using water-oil relative permeability, there is a second term that is often encountered. This is “normalized” relative permeability. Normalized relative permeability defines the oil relative permeability at the critical water saturation (where water becomes mobile) as a value of one (1.0). Normalized relative permeability defines the absolute permeability as the effective permeability at the critical water saturation.

Reserve evaluation

Reserve evaluation is the process of forecasting the production of existing and planned wells and using these forecasts in combination with economic data to estimate monetary value. This value can be used for determining whether to develop a reservoir, buy or sell a field, or to try and attract investment in a company. In order to provide consistent comparisons between projects, properties, and total companies, evaluation of current and future production values use a classification system. This classification system is used to categorize the uncertainty of production forecasts. Generally, the desired result of the evaluation is to obtain the net present value (NPV) of the project, property, or company.

The process of conducting a reserve evaluation entails the application of a consistent set of rules across several disciplines. Key elements of a reserve evaluation include:

- Estimation of remaining reserves
- Generation of production forecasts
- Categorization of risk and designation of current production status
- Summary of interests and burdens
- Estimation of future capital costs
- Fixed and variable operating costs
- Generation of cash flow analysis to evaluate for net present value and other key economic parameters, such as payout and rate of return on investment.

Purpose

Two useful products of a reserve evaluation are the net present value and the production forecasts used to generate net present value. These two estimates can be used in different ways depending on the purpose and required information. The table below shows examples of typical parties who have an interest in reserves evaluations.

Party	Reserves and Production Forecasts	Reserves and Net Present Value
Accountants	--	Creation of financial reports, ceiling tests and depletion calculations
Banks / lending institutions	--	Act as a basis for securing loans
Financial institutions and investors	--	Evaluate the performance of a company
Gas Marketers	Contracts for how much can be produced and pipeline transportation services	--
Governments	Resource development policy decision making	--

Party	Reserves and Production Forecasts	Reserves and Net Present Value
Investors and others	Rely on producer information to determine supply and demand	--
Lawyers	--	Used to settle disputes over reserves and values, estates
Pipeline companies	Planning for pipeline capacity	--
Producers	Development decisions, allocation of future capital	Determining the market value of a company
	Equipment sizing calculations	Making investment decisions
Securities Commissions (SEC, ASC, etc.)	--	Require reserves and cash-flow statements of publicly traded companies

Reserve Classifications

The oil / gas in a reservoir can be divided into two categories: reserves and resources. Reserves refer to oil / gas in a reservoir that has been confirmed to exist and is economically recoverable with current technology. Resources refer to oil/gas in a reservoir that is believed to exist but part or all of this volume has not been demonstrated to be productive or commercially recoverable. The volume classified as reserves can be contained within the resource volume.

Further classifications divide these volumes based on their certainty. The classifications from most to least certain are:

- **Proved (1P)** — “Those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.”

- **Probable (2P)** — "Those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated *Proved plus Probable Reserves* (2P or PP). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate."
- **Possible (3P)** — "Those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of *Proved plus Probable plus Possible* (3P or PPP) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate."

The certainty can also be referred to in a probabilistic form as well. P90, P50, P10 are often used in place of 1P, 2P, 3P, even in situations where deterministic methods are used to estimate reserves volumes. P50 represents the quantity for which there is a 50% probability the quantities actually recovered will match or exceed the estimated recovery value. The same definition applies to P90 (90%) and P10 (10%).

The status of reserves is another classification type used. It describes the current ability of a well to produce. There are three status types used:

- **Developed / Producing** — The wells and facilities required for production are in place. Expected to be recovered from completion intervals that are open and producing at the time of the estimate.
- **Developed / Non-producing** — The wells and facilities required for production are in place. The well or zone is not currently producing, but requires little or no capital expenditure to be brought on production.
- **Undeveloped** — Significant capital expenditure is required for the well to come on production.

The following acronyms are typically used to define reserve classifications:

Acronym	Definition
PDP	Proved Developed Producing
PPDP	Proved plus Probable Developed Producing
PPDP	Proved plus Probable plus Possible Developed Producing

Acronym	Definition
PNP	Proved Developed, Non-Producing
PPNP	Proved plus Probable Developed, Non-Producing
PPPNP	Proved plus Probable plus Possible Developed, Non-Producing
PUD	Proved Undeveloped
PPUD	Proved plus Probable Undeveloped
PPPUD	Proved plus Probable plus Possible Undeveloped
TP	Total Proved
TPP	Total Proved plus Probable
TPPP	Total Proved plus Probable plus Possible

Reservoir flow

Flow in a reservoir is often characterized as being one of two types: transient or boundary-dominated.

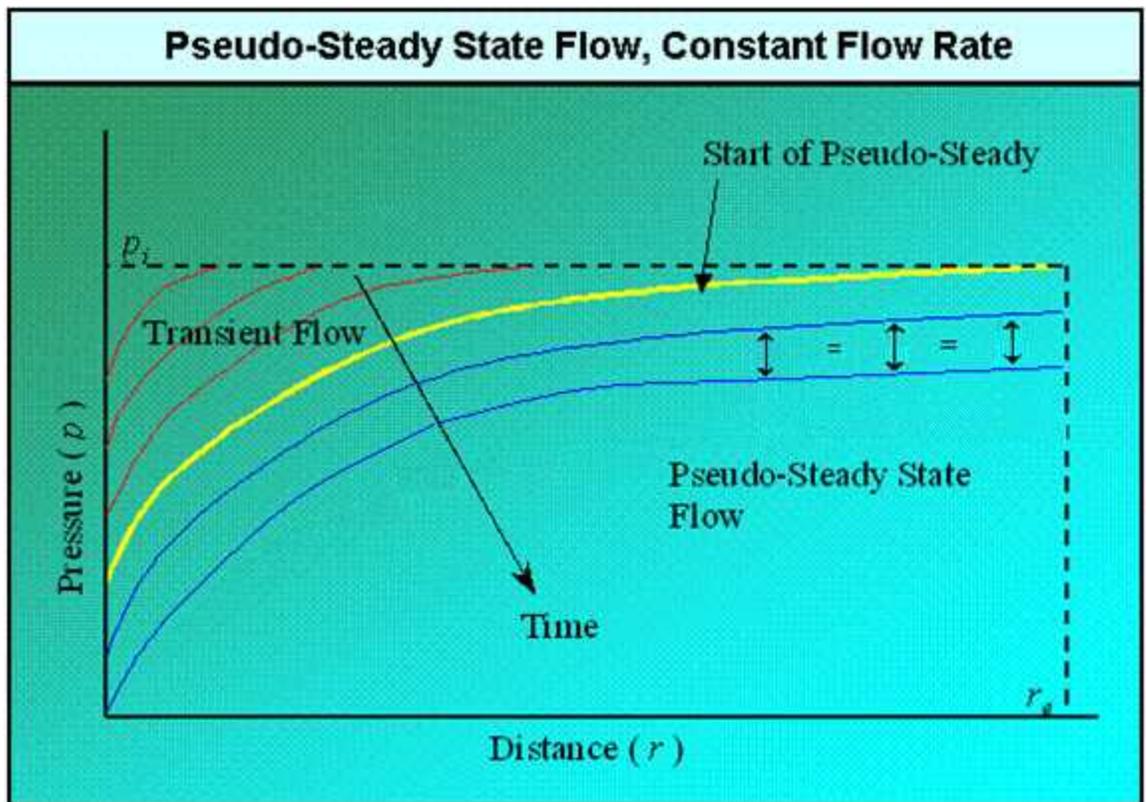
Transient flow takes place during the early life of a well, when the reservoir boundaries have not been felt, and the reservoir is said to be infinite-acting. During this period, the size of the reservoir has no effect on the well performance, and reservoir size cannot be determined except to deduce minimum contacted volume. Since the boundary of the reservoir has not been contacted during the transient flow period, static pressure at the boundary remains constant.

Pressure transient analysis / well testing theory relies heavily on the assumption that the well flows at a constant rate. Several terms are often used when describing flow from a well at constant rate:

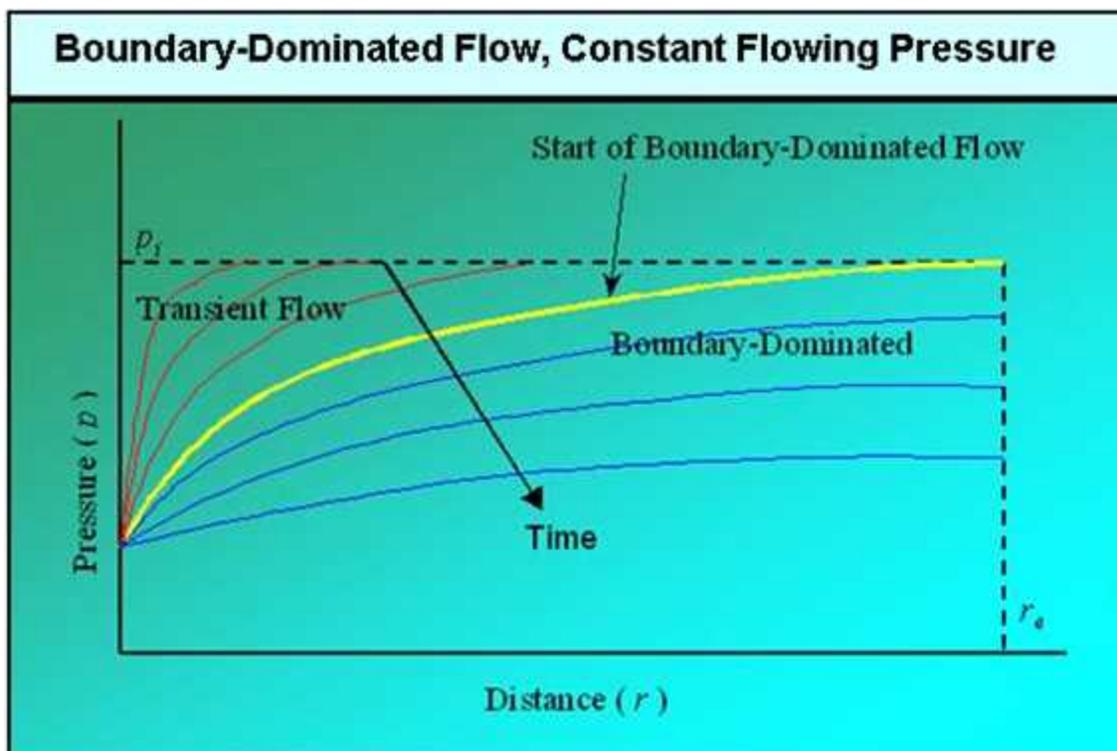
- **Transient Flow** — The pressure transient migrates outward from the well without encountering any boundaries.
- **Steady State Flow** — The pressure transient has reached all of the boundaries but the static pressure at the boundary does not decline. This is often called “constant pressure boundary”.

- **Pseudo-Steady State Flow** — The pressure transient has reached all of the boundaries and the static pressure is declining at the boundary and declining uniformly throughout the reservoir.
- **Boundary-Dominated Flow** — The pressure transient has reached all of the boundaries and the static pressure is declining at the boundary, but not uniformly because the flow rate is not constant. This is also often called “tank-type flow”.

The following schematic chart shows the pressure distribution in the reservoir for a constant flow rate. The red lines represent the transient portion and the blue lines the pseudo-steady-state portion. The yellow line indicates the transition from transient to a pseudo-steady state. Note that the vertical distance between each line is uniform from near wellbore to the boundary.



The following schematic chart shows the pressure distribution in the reservoir for a constant-flowing pressure solution. Note that the flowing pressure of the wellbore is constant and the pressure distribution through the reservoir is not uniform.



The constant rate and constant-pressure solutions are boundaries that the actual wells approach, but never really achieve. Early production and formal production tests often very closely approach the constant-rate solution, whereas late time production generally very closely approaches the constant-pressure solution. Constant-rate solutions are important for conducting pressure transient analysis (PTA) for determination of key reservoir parameters such as permeability and damage, whereas the constant-pressure solutions are important for determination of original in-place volumes and recoverable reserves.

Reservoir fluid properties

Gas

A gas can be defined as a homogenous fluid of low density and low viscosity, which has neither independent shape nor volume. It expands to completely fill the vessel in which it is contained. The properties of gases differ from liquids mainly because the molecules in gases are much further apart than liquids. The ideal gas law states:

$$pV = nRT$$

This equation has limited practical value because no known gas behaves as an ideal gas. However, this equation does describe the behavior of most real gases at low pressures, and it serves as a starting point to develop equations of states for real gases at elevated pressures. Furthermore, the behaviors of most real gases do not deviate drastically from the behavior predicted by this equation. By inserting a correction factor (Z) into the ideal gas equation, real gas behavior can be accurately predicted.

$$pV = ZnRT$$

The correction factor is called the gas compressibility factor; and represents the deviation from ideal gas behavior.

Gravity

Gas gravity is the molar mass (molecular weight) of the natural gas divided by the molar mass of air (28.94 kg / kmol). It ranges from 0.55 for dry sweet gas to approximately 1.5 for wet sour gas. Petroleum gases typically have a gravity of about 0.65.

The gas gravity affects the calculations of gas viscosity, compressibility, compressibility factor, and solution gas-oil-ratio.

Compressibility factor

The gas compressibility factor of a natural gas is a measure of its deviation from ideal gas behavior. The gas compressibility factor is the ratio of the volume actually occupied by a gas at a given pressure and temperature to the volume the gas would occupy at the same pressure and temperature, if it behaved like an ideal gas.

$$Z = \frac{V_{actual}}{V_{ideal}}$$

The gas compressibility factor is usually between 0.8 and 1.2, but it can be as low as 0.3 and as high as 2.0. It is used in the calculation of gas pseudo-pressures, and in converting gas volumes and rates from standard conditions to reservoir conditions (and vice versa). It is sometimes called the super-compressibility factor, and is often confused with the term "compressibility", which is the change in volume per unit change in pressure. The gas compressibility factor directly affects the gas compressibility.

Compressibility

Gas compressibility is the relative change in volume per unit change in pressure. The gas compressibility should not be confused with the gas compressibility factor. The gas compressibility is a very strong function of pressure and increases as the pressure decreases.

Gas compressibility, when plotted versus pressure, shows a discontinuity at the dew point pressure. When the gas is undersaturated (that is, the pressure is greater than the dew point pressure), mathematically it can be expressed as:

$$c_g = -\frac{1}{B_{gd}} \frac{dB_{gd}}{dp}$$

or

$$c_g = \frac{1}{p} - \frac{1}{Z} \frac{dZ}{dp}$$

Where p is the specified pressure, B_{gd} is the dry gas formation volume factor, and Z is the gas compressibility factor at that pressure. Thus, the magnitude of gas compressibility is of the order of $1/p$.

When the gas is saturated (that is, pressure is less than the dew point pressure), it is expressed as:

$$c_g = -\frac{1}{B_{gd}} \frac{dB_{gd}}{dp} + \frac{1}{B_{gd}} \frac{B_o - B_{gd}R_s}{1 - R_sR_v} \frac{dR_v}{dp}$$

Where B_o is the oil formation volume factor, R_s is the solution gas ratio, and R_v is the vaporized oil ratio.

Formation volume factor

The gas formation volume factor is the gas volume at reservoir conditions divided by gas volume at standard conditions. It is used to convert surface measured volumes to reservoir conditions, assuming that the fluid is in a single-gas phase despite temperature and pressure changes. Defined below, it is a function of the fluid composition and the pressure / temperature ratio between reservoir (in-situ) and standard conditions (14.65 psia and 519.67 °R or 60 °F):

$$B_g = \frac{V_{reservoir}}{V_{surface}} = \frac{14.65TZ}{519.67p}$$

It is a very strong function of pressure, and a weak function of temperature and gas composition.

The dry gas formation volume factor is the gas volume at reservoir conditions divided by the gas volume at standard conditions. It is used to describe the gas volume change from the reservoir to the surface, taking into account the phase change between gas and liquid.

$$B_{gd} = \frac{V_{reservoir}}{V_{surface}}$$

Vaporized oil ratio (R_v)

For condensate gas and volatile oil reservoirs with a gas cap, the liquid component in the reservoir gas needs to be considered. This is described by the vaporized oil ratio (R_v). R_v is defined as the ratio of the volume of produced stock tank condensate or oil to the volume of produced separator gas (commonly used unit is stb/MMscf). It is used in the modified black oil (MBO) models.

Viscosity

Gas viscosity is a measure of the resistance to flow exerted by the gas and is given in units of centipoises (cp). Higher values indicate more resistance to flow. For gas, the viscosity increases with increasing temperature and pressure. As pressure decreases, gas viscosity decreases. The molecules are simply further apart at lower pressure and move past each other more easily.

Experimental determination of gas viscosity is difficult. Usually it is not measured but obtained from correlations, which include corrections for H_2S , CO_2 , and N_2 . Gas viscosity is used in numerous equations, most notably in the definitions of pseudo-pressure and pseudo-time. Typically, gas viscosity is in the range of 0.015 to 0.03 cp or 15 to 30 micro-Pa-s.

Critical temperature

Gases can be converted to liquids by compressing the gas at a suitable temperature. As the temperature increases, the kinetic energies of the particles that make up the gas also increase, and the gases become more difficult to liquefy. The critical temperature of a substance is the temperature at and above which vapor of the substance cannot be liquefied, no matter how much pressure is applied. For example, the critical temperature of water is 374°C and carbon dioxide is 31.2°C.

Critical temperature represents the temperature above which distinct liquid and gas phases do not exist. As the critical temperature is approached, the properties of the gas and liquid phases become the same, resulting in one phase known as supercritical fluid. The critical temperature value is used in the definition of reduced temperature ($T_r = T / T_c$), which in turn is used directly in correlations or equations of state to determine various PVT properties of natural gases (for example, viscosity, compressibility, gas compressibility factor, etc.).

Critical pressure

The critical pressure of a substance is the pressure required to liquefy a gas at its critical temperature. For example, the critical pressure of water is 217.7 atm and carbon dioxide is 73.0 atm.

Critical pressure represents the pressure above which distinct liquid and gas phases do not exist. As the critical pressure is approached, the properties of the gas and liquid phases become the same, resulting in one phase known as supercritical fluid. The critical pressure value is used in the definition of reduced pressure ($p_r = p / p_c$), which in turn is used directly in correlations or equations of state to determine various PVT properties of natural gases (for example, viscosity, compressibility, gas compressibility factor, etc.).

Oil

Correlations of physical properties of reservoir crude oils are more complicated than those for natural gas because of the many different components they contain. Although most components are hydrocarbons, the larger molecule components can be different chemical classes. These larger, heavier components can strongly influence the behavior of the mixture. Also the mixing rules for liquids are considerably different than those for gases because of the complex nature of hydrocarbon liquids.

There are three main sources for developing key oil properties.

1. Subsurface sampling of the produced fluid at reservoir conditions. This is the best method because the complex mixtures of hydrocarbons make each oil unique. The individual properties can then be determined empirically in a laboratory.
2. Surface sampling at a separator where the rate of flow for each fluid, gas and liquids, is measured along with their respective compositions. These fluids are then recombined in the laboratory at reservoir conditions, and the resulting fluid is used to empirically determine key oil properties.
3. Correlations are often used when only key parameters, such as the density of the produced oil and the volume of solution-gas evolved, are known. Correlations should be

used only after being proved / tuned with laboratory measurements for subsurface samples of analogous oils.

Gravity

Oil gravity relates the density of oil to that of the density of water. The oil gravity has a very strong effect on the calculated oil viscosity and solution gas-oil ratio. It has an indirect effect on the oil compressibility and the oil formation volume factor because these variables are affected by the solution gas-oil ratio.

The American Petroleum Institute (API) developed a specific gravity scale that measures the relative density of various petroleum liquids. API gravity is gradated in degrees on a hydrometer instrument and was designed so that most values would fall between 10° and 70° API.

Usually the oil gravity is readily known. It ranges from 45 °API (light oil) through 20 °API (medium density) to 10 °API (heavy oil). The conversion from API gravity (oil field units) to relative gravity (relative to water) is:

$$\gamma_o = \frac{141.5}{^\circ API + 131.5}$$

The conversion of oil relative gravity to oil density is:

$$\rho_o = \gamma_o \cdot \rho_w$$

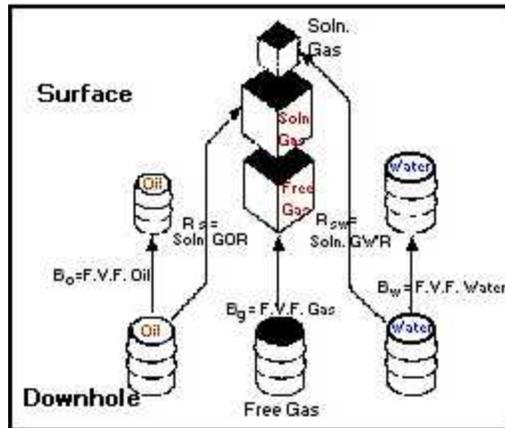
where:

$$\rho_w \approx 62.37 \text{ lb}\cdot\text{m} / \text{ft}^3 \text{ or } 1000 \text{ kg} / \text{m}^3$$

Formation volume factor

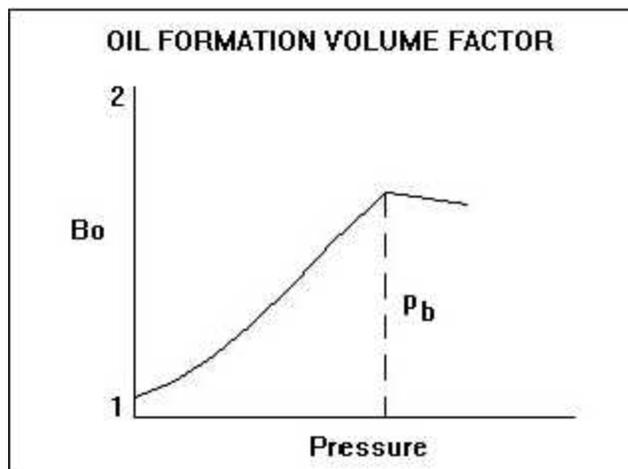
The oil formation volume factor (FVF) is defined as the ratio of the volume of oil and dissolved gas at reservoir (in-situ) conditions to the volume of oil at stock tank (surface) conditions. Since most measurements of oil and gas production are made at the surface, and the fluid flow takes place in the formation, volume factors are needed to convert measured surface volumes to reservoir conditions. It is defined as:

$$B_o = \frac{V_{res}}{V_{surface}}$$



Note: F.V.F. → Formation Volume Factor

The oil formation volume factor is influenced by two main factors: solution gas and the compressibility of oil. The dominant factor is solution gas. As pressure increases, the amount of solution gas that the oil can dissolve increases such that the oil swells, and so the formation volume factor exceeds 1.0. After there is no remaining free gas available to dissolve in the oil, further increases in pressure result in a decline in formation volume factor due to the second influencing factor – the compressibility of oil. As shown in the diagram below, the oil formation volume factor is dominated by swelling below the bubble point pressure (due to dissolved gas), and by compressibility above the bubble point pressure (because all available gas is now dissolved).



Shrinkage

Shrinkage is the inverse of the formation volume factor for oil, and represents the difference between the volume of oil in the reservoir and its volume when produced to the surface (standard pressure and temperature). The value of shrinkage is generally between 0.5 and 1, and the change in volume is due to solution gas coming out of the oil as the pressure decreases.

Compressibility

Oil compressibility is defined as the relative change in oil volume per unit change in pressure. Oil compressibility is a source of energy for fluid flow in a reservoir. In an undersaturated reservoir, it is a dominant drive mechanism, but for a saturated reservoir, it is overshadowed by gas compressibility effects due to the evolution of dissolved gas. Oil compressibility is a component of total compressibility, which is used in the determination of skin, dimensionless time, and material balance.

Oil compressibility, when plotted versus pressure, shows a significant discontinuity at the bubble point pressure. Above this pressure (undersaturated condition), the oil is a single-phase liquid consisting of oil and dissolved gas. The compressibility of this liquid can be measured in the laboratory, and it is a weak function of pressure. Mathematically, it can be expressed as:

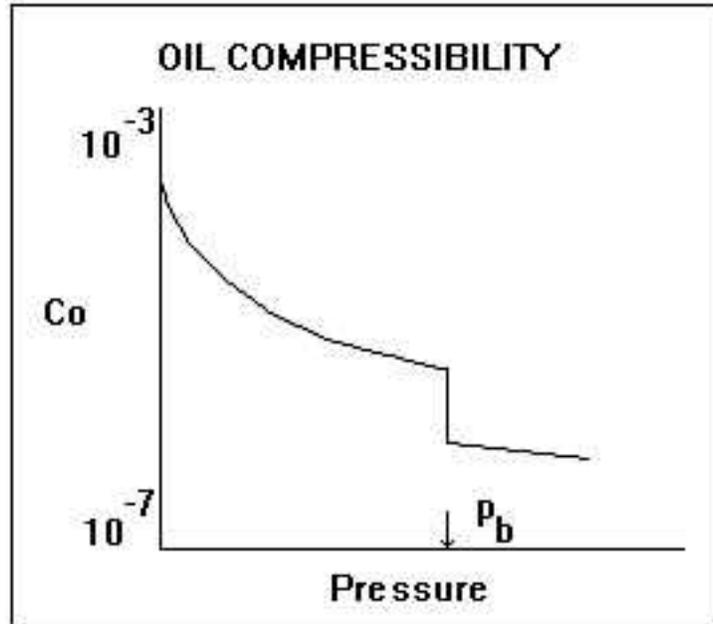
$$c_o = -\frac{1}{B_o} \frac{dB_o}{dp}$$

Where B_o is oil formation volume factor.

Below the bubble point pressure (saturated condition), gas comes out of solution causing a sharp increase in compressibility, which causes the discontinuity shown in the plot. While below the bubble point pressure, oil compressibility becomes a much stronger function of pressure. It can be expressed as:

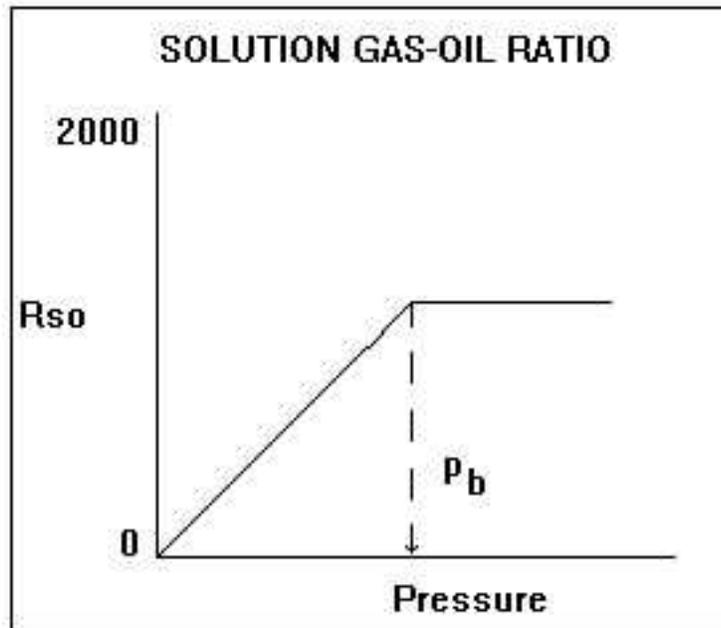
$$c_o = -\frac{1}{B_o} \frac{dB_o}{dp} + \frac{1}{B_o} \frac{B_{gd} - B_o R_v}{1 - R_s R_v} \frac{dR_s}{dp}$$

Where B_{gd} is the dry gas formation volume factor, R_s is the solution gas ratio, and R_v is the vaporized oil ratio.



Solution gas-oil ratio

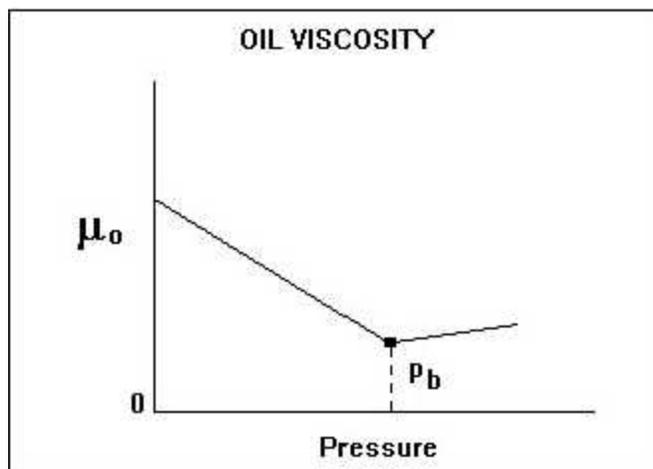
The solution gas-oil ratio is the amount of gas dissolved in the oil at any pressure. It increases approximately linearly with pressure and is a function of the oil and gas composition. A heavy oil contains less dissolved gas than a light oil. In general, the solution gas-oil ratio varies from 0 (dead oil) to approximately 2000 scf/bbl (very light oil). The solution gas-oil ratio increases with pressure until the bubble point pressure is reached, after which it is a constant, and the oil is said to be undersaturated.



The solution gas-oil ratio is a significant component of the PVT correlations. It has a very significant influence on the oil formation volume factor, the oil viscosity, and the oil compressibility.

Viscosity

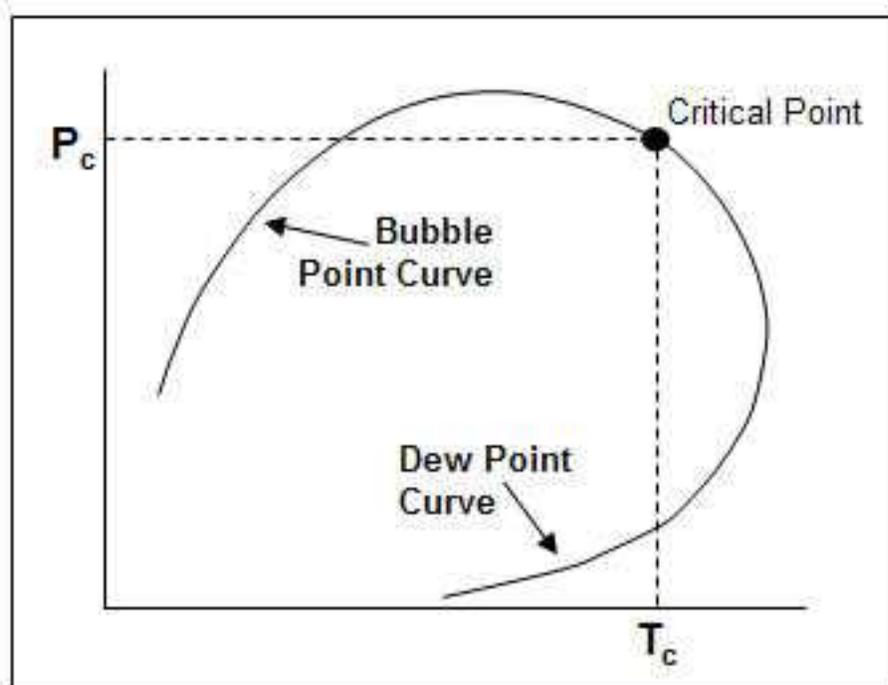
Oil viscosity is a measure of the resistance to flow exerted by the oil, and is given in units of centipoises (cP). Higher values indicate greater resistance to flow. For oil, the viscosity decreases with increasing temperature and pressure (up to the bubble point). Above the bubble point pressure, oil viscosity increases minimally with increasing pressure as shown below. It is a very strong function of reservoir temperature, oil gravity, and the solution gas-oil ratio.



Oil viscosity is measured as a function of pressure in most PVT laboratory measurements. Occasionally, a routine oil analysis report quotes the oil viscosity (and the kinematic viscosity). These measurements are at stock tank conditions and should not be used as the in-situ oil viscosity. Dead-oil viscosity is defined as the viscosity of crude oil at atmospheric pressure (no gas in solution) and system temperature. There are several correlations available for estimating oil viscosity at reservoir conditions, but great care must be taken since they are very sensitive to the oil gravity and solution gas-oil ratio inputs. The oil viscosity at reservoir conditions can vary from 10,000 cP for a heavy oil to less than 1 cP for a light oil.

Bubble point pressure

The bubble point pressure is defined as the pressure at which the first bubble of gas comes out of solution. At this point, we can say the oil is saturated – it cannot hold anymore gas. Above this pressure, the oil is undersaturated, and the oil acts as a single-phase liquid. At and below this pressure, the oil is saturated, and any lowering of the pressure causes gas to be liberated resulting in two-phase flow.



Water

Estimating reservoir water properties is important for reservoir engineering calculations, specifically for those with water influx. Also, water is often a very important liquid component of an

oil and gas production system. The physical properties of water play an important role in multiphase flow calculations.

Because water composition is only generally affected by dissolved solids, correlating water properties is relatively simple. Also, changes in the physical properties of water as a function of temperature and pressure are relatively small and usually can be predicted.

Water-specific gravity

Water-specific gravity is defined as the density of the water divided by the density of water at standard conditions (62.3 lb / ft³). Water contained in a reservoir is saline and usually has a specific gravity greater than 1.0. Water-specific gravity has no effect on calculated properties such as water compressibility, formation volume factor, and viscosity. It is used however, in the wellbore pressure-drop calculations when converting pressures from wellhead to sandface.

Salinity

Salinity is the quantity of dissolved salt in water, and is usually expressed as the mass of dissolved salt in a unit volume solution, in mg / L, or parts per million (ppm). Salinity is often reported as total dissolved solids (TDS).

Viscosity

Water viscosity is a measure of the resistance to flow exerted by water. Higher values indicate more resistance to flow. For water, the viscosity decreases with increasing temperature, and increases with increasing pressure. Water viscosity is a very weak function of pressure. Water at room temperature is approximately equal to 1 cP. In a reservoir, it is typically between 0.5 to 1 cP. This is due to the higher temperature, salinity, and the solution-gas content of water.

Compressibility

The compressibility of any substance is the change in volume per unit volume per unit change in pressure. Water compressibility is a source of energy for fluid flow in a reservoir, but it is only significant when there is no free gas present in the reservoir. The value of water compressibility can be obtained from laboratory PVT measurements, or it can be determined from correlations. The magnitude is approximately between 1.0×10^{-6} and 9.0×10^{-6} psi⁻¹. It is a weak function of pressure, temperature, and salinity.

Formation volume factor

The water formation volume factor is defined as the ratio of the volume of water at reservoir (in-situ) conditions to that at stock tank (surface) conditions. This factor is used to convert the flow rate of water (at stock tank conditions) to reservoir conditions.

$$B_w = \frac{V_{res}}{V_{surface}}$$

The water formation volume factor can be measured in the laboratory, or it can be determined from correlations. In most situations, the water formation volume factor is very close to one, and so most practitioners tend to set it to one. It is a very weak function of pressure, temperature, and salinity.

Dissolved gas / water ratio

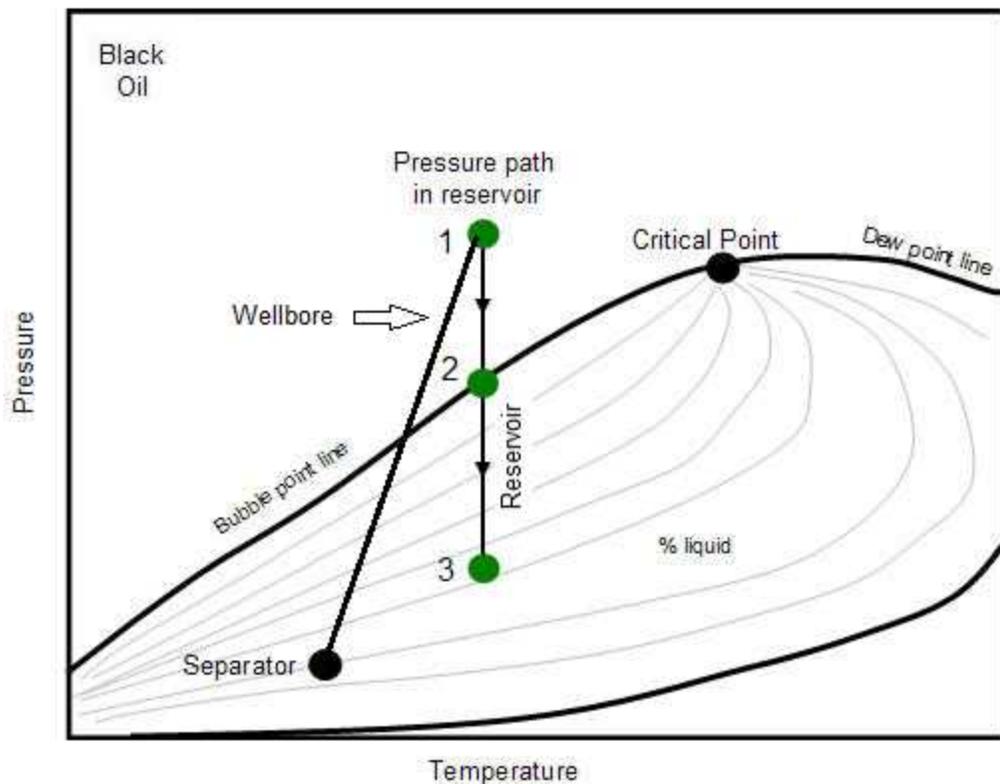
The solution gas / water ratio is the amount of gas dissolved in the water. It increases approximately linearly with pressure, and is a function of the water and gas composition. Quantitatively, the solubility of gas in water is considerably less than that of gas in oil.

Reservoir fluid types

Typically, there are five main types of reservoir fluids: black oil, volatile oil, condensate (retrograde gas), wet gas, and dry gas. Each of these fluid types require different approaches when analyzing the reservoir, so it is important to identify the correct fluid type early on in the reservoir's life. Laboratory analysis is our primary method for determining and quantifying fluid type, but production information such as initial production gas-oil ratio (GOR), gravity of the stock-tank liquid, and the color of the stock-tank liquid are also useful indicators.

Black oils

Black oils are made up of a variety of components including large, heavy, and non-volatile hydrocarbons. The phase diagram is shown below. When the reservoir pressure lies anywhere along line 1 → 2, the oil is said to be undersaturated - meaning the oil could dissolve more gas if more gas were present. If the pressure is at 2, the oil is at its bubble point, and is said to be saturated - meaning the oil contains the maximum amount of dissolved gas and can't hold any more gas. A reduction in pressure at this point will release gas to form a free gas phase inside the reservoir. Additional gas evolves from the oil as it moves from the reservoir to the surface. This causes some shrinkage of the oil. Black oil is often called low shrinkage crude oil or ordinary oil.

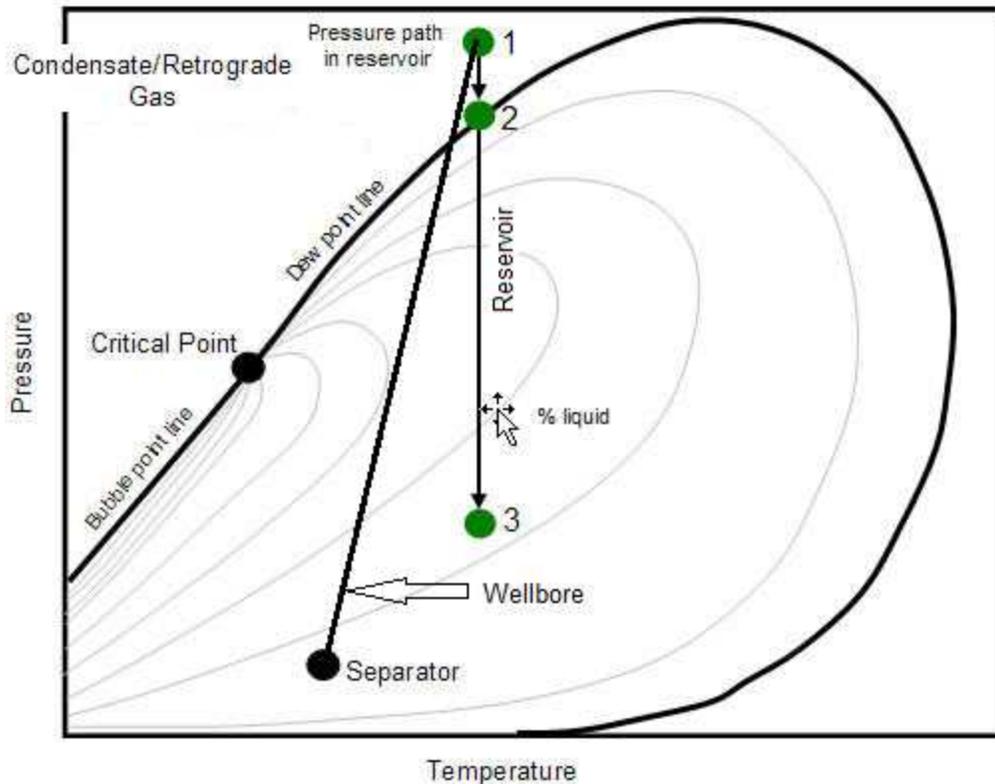


Black oils are dark in color indicating the presence of heavy hydrocarbons. It is characterized as having initial gas-oil ratios of 2000 scf/stb or less. Producing GOR will increase during production when reservoir falls below bubble point pressure, 2 → 3 as the gas evolves from the solution inside the reservoir and flows preferentially to the oil.

Volatile oils

Volatile oils contain fewer heavy molecules and more intermediate components (ethane through hexane) than black oils. Volatile oils generally have initial gas-oil ratios in the 2000 to 3300 scf/Bbl range, and the stock tank gravity is usually 40° API or higher. The color is generally lighter than black oil – brown, orange, or green. Gas associated with volatile oils tends to be very rich and similar to retrograde condensate gas.

The phase envelope for a volatile oil tends to cover a much narrower temperature range when compared to a black oil; but like a black oil, the reservoir temperature is always lower than the critical temperature for the fluid. As the reservoir temperature approaches the critical temperature a volatile oil will become more gas-like such that with even moderate depletion, a volatile oil reservoir can flash mainly to gas and have a relatively low liquid content.

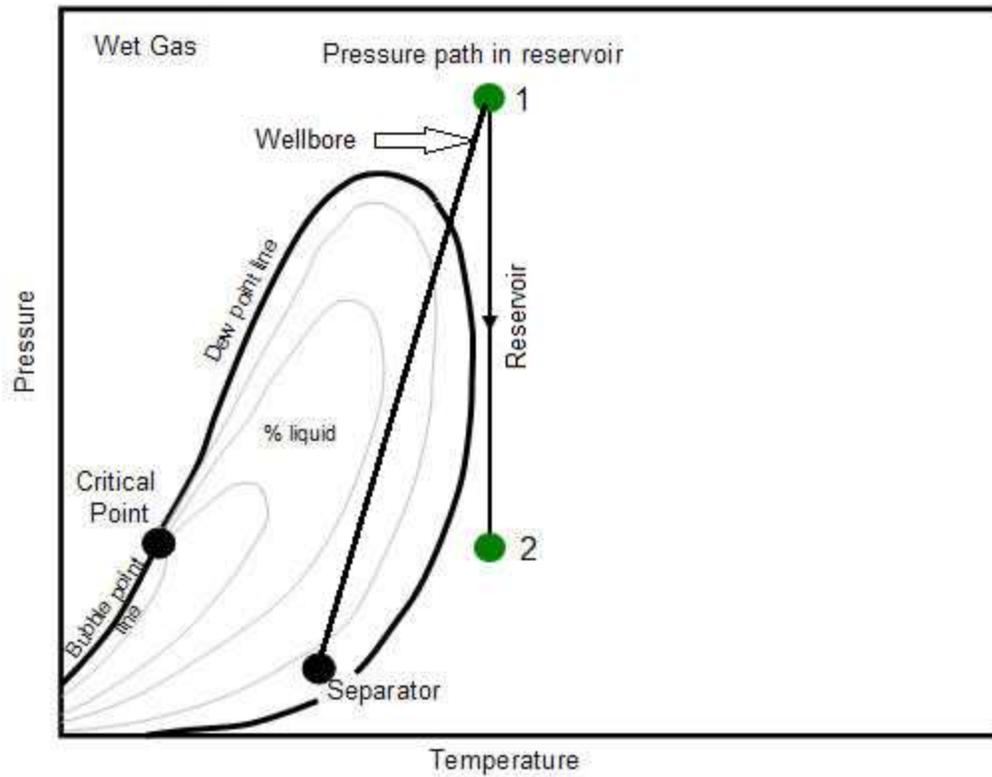


Wet gas (rich gas)

Natural gas that contains significant heavy hydrocarbons such as propane, butane and other liquid hydrocarbons is known as wet gas or rich gas. The general rule of thumb is if the gas contains less methane (typically less than 85% methane) and more ethane, and other more complex hydrocarbons, it is labeled as wet gas.

Wet gas exists solely as a gas in the reservoir throughout the reduction in reservoir pressure. Unlike retrograde condensate, no liquid is formed inside the reservoir. However, separator conditions lie within the phase envelope, causing some liquid to be formed at the surface. This surface liquid is normally called condensate, and the reservoir gas is sometimes called condensate-gas, which leads to a lot of confusion between wet gasses and retrograde condensate.

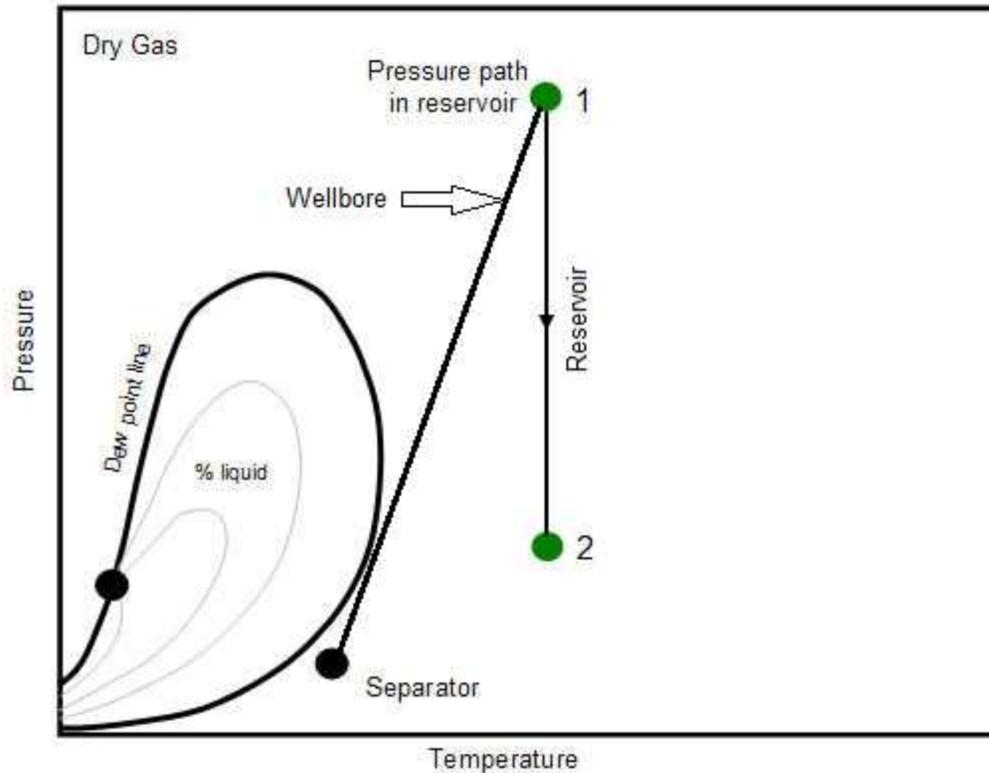
The entire phase diagram of a wet gas will lie below the reservoir temperature. Note that the pressure path line does not enter the phase envelope, meaning no liquid is ever formed inside the reservoir.



Wet gases produce stock tank liquid with the same range of gravities as the liquids from retrograde gases. However, the gravity of the stock tank liquid does not change during the life of the reservoir. Also, producing GOR are very high (> 50000 scf/stb) for wet gases and remains constant.

Dry gas

Natural gas that occurs in the absence of condensate or liquid hydrocarbons, or gas that had condensable hydrocarbons removed, is called dry gas. It is primarily methane with some intermediates. The hydrocarbon mixture is solely gas in the reservoir and there is no liquid (condensate surface liquid) formed either in the reservoir or at surface. The pressure path line does not enter into the phase envelope in the phase diagram, thus there is only dry gas in the reservoir. Note, the surface separator conditions also fall outside the phase envelope (in contrast to wet gas); hence no liquid is formed at the surface separator.



Reservoir properties

This topic describes the key terminology for reservoir properties.

Drainage area

This is the areal extent of the reservoir. It is most often determined from geological information about the formation / region, but it can also be estimated from performance studies such as material balance, interference analysis, and simulation studies.

Expected ultimate recovery

The expected ultimate recovery (EUR) is the amount of oil or gas that can be economically recovered from a reservoir under current operating and economic conditions.

Formation compressibility

Formation compressibility is the change in pore volume per unit of pore volume per unit change in pressure. Even though the formation is a solid material, it is compressible. The formation

compressibility is used in the calculation of total compressibility. It is of the same order of magnitude as the oil compressibility, or the water compressibility, approximately 10^{-6} psi⁻¹.

Thus, in the absence of gas saturation, the formation compressibility is relatively significant and must not be ignored. However, when there is gas present in the pores, the gas compressibility is often one or two orders of magnitude higher, and so the formation compressibility is relatively small and may be ignored.

The formation compressibility may be measured in the laboratory, but it is usually derived from correlations. It is obvious that the nature of the formation, its degree of consolidation, its stress field, etc. all affect the formation compressibility, yet the correlations that exist do not take all of these factors into account. They are very simplified and relate the formation compressibility to the total porosity. The correlation used in Harmony Enterprise is derived from laboratory measurements [Hall, 1953], and is applicable to sandstones and carbonates. For overpressured reservoirs, the formation compressibility can be 10 times larger than suggested by the Hall correlation. In practice, it has been found that formation compressibility for overpressured reservoirs is approximately equal to 10^{-5} psi⁻¹.

Gas saturation

Gas saturation is the fraction of the pore space occupied by gas. Most gas reservoirs also contain some connate (non-movable) water. If the gas reservoir is part of a gas cap in a saturated oil reservoir, the space may contain gas, oil, and water. Thus, the gas saturation is rarely 100% but varies from 30% to 90%.

Gas saturation is used directly in the calculation of the reserves, and also in the calculation of total compressibility.

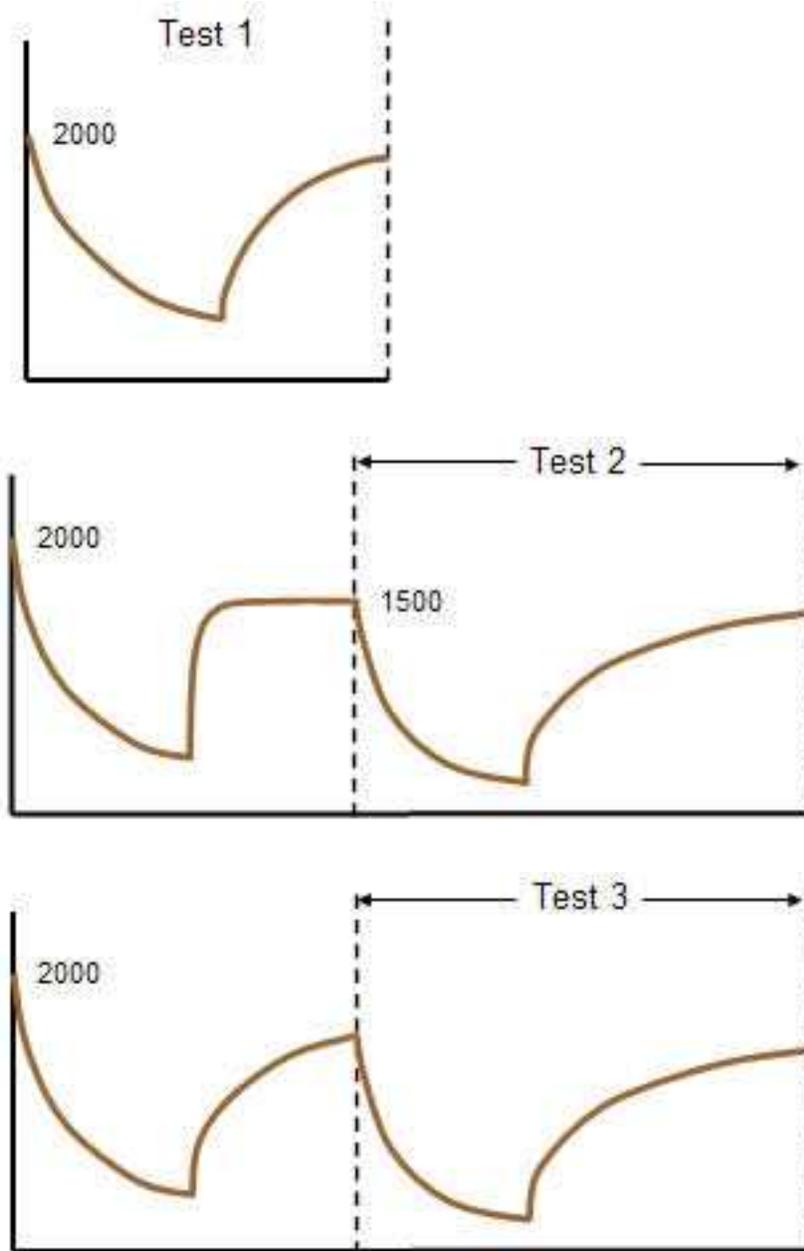
Note that the gas saturation has a significant effect on the total compressibility because the gas compressibility is much higher than the fluid compressibility of oil and water.

Initial pressure

Reservoir pressure is the pressure of fluids within the pores of a reservoir measured at a specific point in time. The initial reservoir pressure is the average reservoir pressure measured in a discovery well before any fluid is produced. This value is necessary for many reservoir engineering calculations, such as reserve determination. Units are typically psi (field units) or kilopascals (SI).

For well testing, the initial pressure is the average reservoir pressure before the start of a test. For a new well, a well that has not been put on production, the initial pressure equals the virgin or original pressure and corresponds to a drillstem test pressure. For a well that has been on

production for a long time, the initial pressure may or may not be equal to the original reservoir pressure. The following example illustrates this concept.



- If Test 1 is being analyzed, the initial pressure is 2000.
- If Test 2 is being analyzed, the initial pressure is 1500 because the reservoir pressure is fully built up before this test, and the historical pressure

prior to Test 2 does not apply. Thus, it behaves like a new well with an initial pressure 1500.

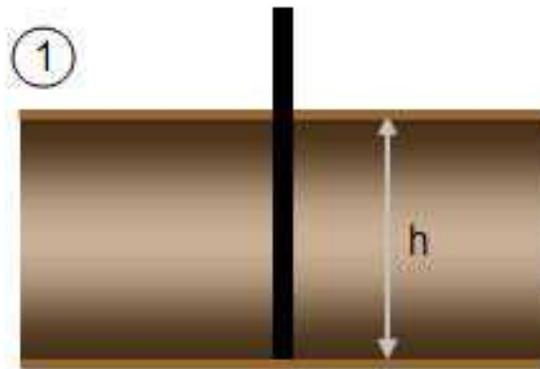
- If Test 3 (which is a combination of Test 2 and some production prior to Test 2) is being analyzed, the initial pressure is 2000, because it must reflect the reservoir pressure before the production that is being analyzed during the test.

Mid-point of perforations

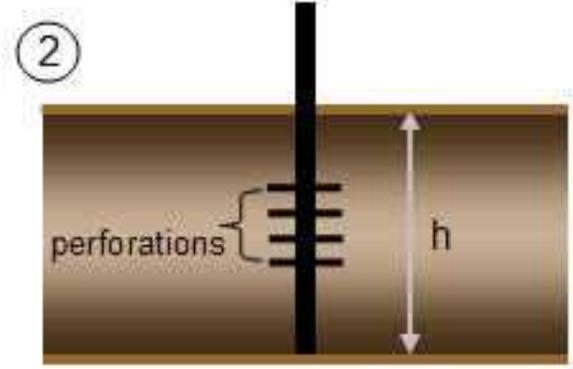
Perforations are the communication tunnel created from the casing or liner into the reservoir formation through which the oil or gas is produced. The mid-point of perforations is the measured depth from the surface to the mid-point of the perforated interval of the formation.

Net pay

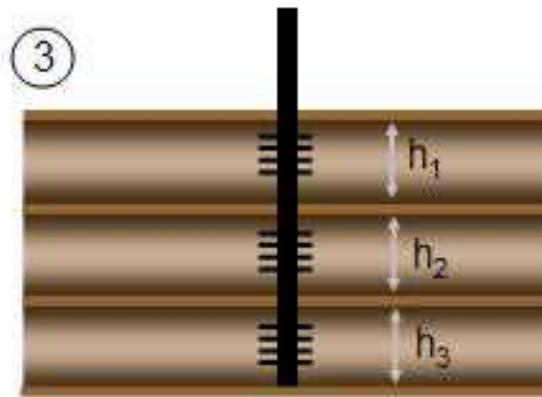
Net pay is the thickness of the formation that contributes to the flow of fluids, or the sum of the productive intervals of a reservoir. It is determined from core or log analysis, and can be different from the gross pay or the perforated interval. In the case of an inclined or deviated wellbore in a declining formation, the net pay is measured perpendicular to the angle of decline. Several examples of net pay are shown below.



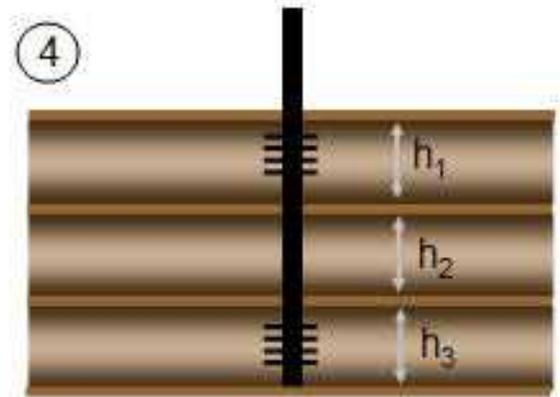
net pay = h



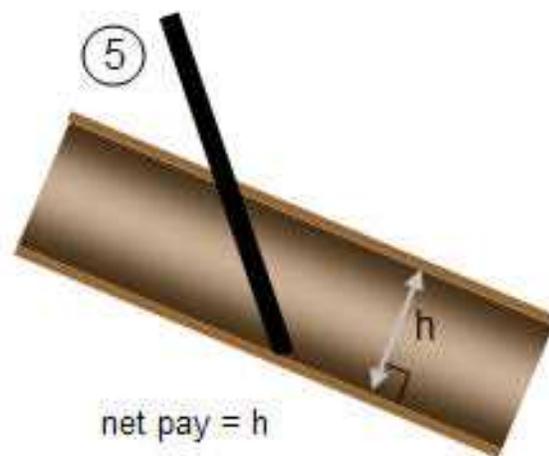
net pay = h



net pay = $h_1 + h_2 + h_3$



net pay = $h_1 + h_3$



net pay = h

Oil saturation

Oil saturation is the fraction of the pore space occupied by oil. Most oil reservoirs also contain some connate (non-movable) water. Thus, the oil saturation is rarely 100% and usually ranges from 10% to 90% (in the oil / water transition zones). The oil saturation affects the oil and gas reserves, and is also used in the calculation of total compressibility.

Original fluid-in-place

Original fluid-in-place (OFIP) is the amount of fluid contained in a reservoir at standard conditions, as calculated from the reservoir and fluid properties. It is a general term that refers to the calculation of original gas-in-place (OGIP) and/or original oil-in-place (OOIP).

Porosity

The total porosity is the percentage volume occupied by the pore space, regardless of the type of fluids contained in the pore space. It is obtained from core or log analysis. Total porosity is used to calculate volumetric reserves and formation compressibility, and is used in the pressure transient flow equations.

The total porosity has only a small effect during the transient flow period (it occurs within the log term in the skin calculation equation for radial flow), but it has a significant effect during pseudo-steady state (PSS) flow, as it directly affects the reserves contained in the reservoir.

Rock volume

The total volume of reservoir rock, often referred to as the bulk volume.

Pore volume

The total volume of pore space within the reservoir as determined by the porosity of the rock.

Hydrocarbon pore volume

The total pore volume containing hydrocarbons. This is generally the product of pore volume and water saturation.

Recovery factor

The recovery factor (RF) is the ratio of the expected ultimate recovery and original gas/oil-in-place. It indicates how much of the original gas/oil-in-place can be recovered under current operating and economic conditions.

Reservoir temperature

The reservoir temperature represents the temperature of the formation. It increases with reservoir depth and differs widely depending on the reservoir location's geothermal gradient. The geothermal gradient is the rate of increase in temperature per unit depth in the earth. Although the gradient is variable depending on location, a typical average value is 15°F / 1000 ft.

In the analysis of gas wells, the reservoir temperature is used directly in the pressure transient analysis calculations, as well as calculating all the gas fluid properties, such as the gas formation volume factor, gas viscosity, and gas compressibility.

In the analysis of oil wells, the reservoir temperature does not enter into the pressure transient analysis equations directly; rather it is used in calculating oil fluid properties such as the oil formation volume factor, oil viscosity, oil compressibility, and solution gas-oil ratio.

Units are typically Rankine (field units) or Kelvin (SI).

Total compressibility

The compressibility of a substance is the change in volume per unit volume per unit change in pressure. In a reservoir that consists of rock and pore space occupied by oil, water, and gas, the total compressibility is defined as follows:

$$c_t = c_g S_g + c_o S_o + c_w S_w + c_f$$

From this definition, the total compressibility takes into account the compressibility and saturation of gas, oil, and water, as well as the (rock) formation compressibility. Note that the gas saturation has a significant effect on the total compressibility because the gas compressibility is much higher than the other fluid compressibility (oil and water). Thus, if there is any gas present in the reservoir, the total compressibility is dominated by the gas compressibility component.

In well testing and rate transient analysis, the analysis of pressure and production data is based on the solution of the diffusivity equation. The analytical solution of this equation assumes that the total compressibility is constant. This assumption is valid for single-phase liquid systems. In gas systems, because compressibility of gas is highly dependent on pressure, the assumption of a constant value of total compressibility can lead to serious errors, especially when the reservoir has started to deplete (that is, during boundary-dominated flow). To account for this changing gas compressibility, the concept of pseudo-time is invoked. It accounts for the variation with pressure of compressibility, viscosity, and permeability.

The units of compressibility are 10^{-6} psi⁻¹. ($1 * 10^{-6}$ psi⁻¹ (sometimes referred to as 1 Microsip.)

- $c_o \approx c_w \approx c_f \approx 10^{-6} \text{ psi}^{-1}$
- $c_g \approx 10^{-3} \text{ psi}^{-1}$ @ 500 psi
- $c_g \approx 10^{-3} \text{ psi}^{-1}$ @ 1000 psi
- $c_g \approx 10^{-4} \text{ psi}^{-1}$ @ 2500 psi
- $c_g \approx 10^{-4} \text{ psi}^{-1}$ @ 5000 psi
- $c_g \approx 10^{-5} \text{ psi}^{-1}$ @ 10,000 psi
- $c_g \approx 10^{-5} \text{ psi}^{-1}$ @ 15,000 psi

Water saturation

Water saturation is the fraction of the pore space occupied by water. Most reservoirs are water wet and contain connate water. Water saturation may range from 10% to 50% for an oil or gas reservoir, and it is 100% for an aquifer. The water saturation obviously affects oil and gas reserves, and it is also used in the calculation of total compressibility.

Wellbore radius

The wellbore radius is half of the measured inside diameter of the borehole at the point of perforation. This is not to be confused with the effective wellbore radius, which accounts for changing skin during production or after stimulation. The wellbore radius and effective wellbore radius are equivalent when the skin is equal to zero.

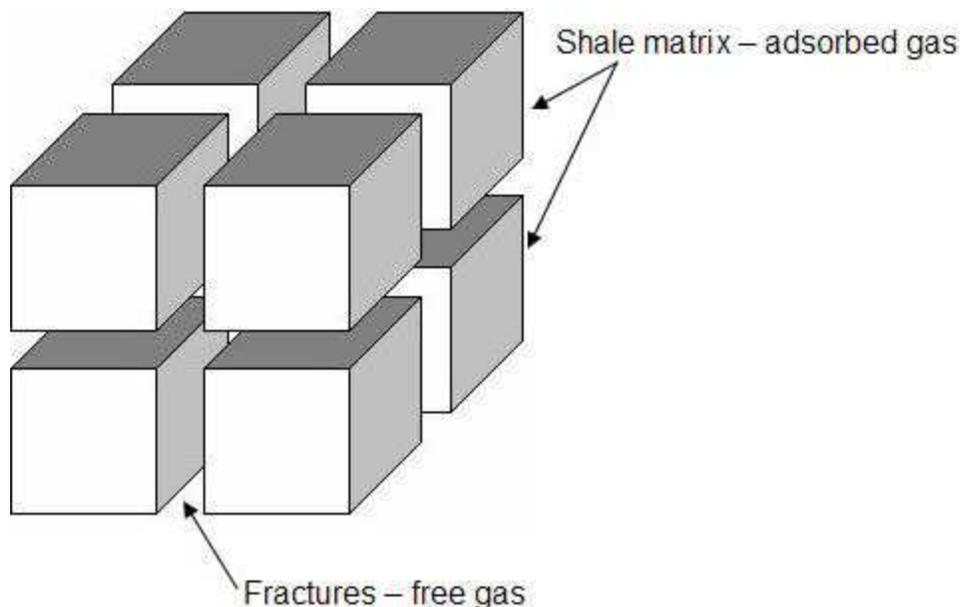
Shale properties

Tight / shale gas reservoirs have very low matrix permeability, and in some instances contain organic-rich rocks where gas can also be adsorbed. For additional information, see [shale adsorption correction](#). Production from these reservoirs requires long horizontal wells with multiple-staged hydraulic fracture treatments to create extensive artificial fracture networks near the wellbore.

To estimate original gas-in-place in tight / shale gas reservoirs, you require:

- Conventional volumetric calculations using rock volume, porosity, fluid saturations, and pressure.
- Use of [Langmuir isotherms](#) to estimate the volume of adsorbed gas.

Typically, all water in a tight / shale gas reservoir is not moveable, so the reported water production is almost always attributable to production of load fluids (completion / fracture treatment fluid).



Conventional vs. tight / shale gas reservoirs

A comparison of conventional and tight / shale gas reservoirs is shown below:

Characteristic	Conventional	Shale
Gas Generation	Gas is generated in the source rock and then migrates into the reservoir.	Gas is generated and trapped within the source rock.
Gas Storage Mechanism	Compression.	Compression and adsorption.
Gas Produced	Free gas only.	Free and adsorbed gas.
Production Performance	Minimal transient period followed by a long boundary-dominated flow period. Production rates are mainly related to permeability and declining reservoir pressure.	Very long transient (linear) flow period that can extend many years. In some cases, it is debatable if boundary-dominated flow will ever be fully realized. Production rates are mainly related to the success of creating a large frac-

Characteristic	Conventional	Shale
	<p>From a traditional decline perspective, 'b' values typically range from 0 to 0.5 but can be somewhat larger if there are commingled layers.</p> <p>Recovery factor = 50% – 90%</p>	<p>ture network around a long horizontal wellbore and to the matrix permeability.</p> <p>From a traditional decline perspective, 'b' values initially equal 2.0 (indicating linear flow), and then transition to <1.0 as boundary-dominated flow becomes prevalent.</p> <p>Recovery factor = 5% – 20%</p>

A comparison of conventional vs. tight / shale gas rate-time plots is shown below:



Shale adsorption correction

The shale adsorption correction is based on SPE paper 131772 by R. Ambrose et al.

In shale reservoirs that display adsorption, it has traditionally been thought that the adsorbed gas resides in the matrix of the organic-rich portion of the rock, which does not contribute significantly to the porosity of the rock. New evidence (Ambrose et al.) suggests that this organic-rich portion of the shale does, in fact, contain the majority of the porosity, as well as the adsorbed gas. If this assumption is valid, it is possible that the adsorbed gas is occupying a portion of the measured porosity, thus decreasing the pore space available to free gas. The volume occupied by the adsorbed gas must therefore be subtracted from the measured pore volume when calculating the volume available for free gas storage. The **Ads. Sat.** (Adsorption Saturation) option in Harmony Enterprise performs this correction.

When gas is adsorbed, the molecules are so close to each other that they exist in a near liquid phase. The adsorption volume correction in Harmony Enterprise converts the measured adsorbed

gas content into a liquid, and subsequently treats this phase as an extra saturation term, similar to water saturation.

When the correction is enabled, an Adsorbed Saturation, “ S_{ads} ” is calculated, and gas saturation is calculated as follows:

$$S_g = (1 - S_w - S_o - S_{ads})$$

To calculate adsorbed saturation, define:

$$\phi = \frac{\text{PoreVolume}}{\text{RockVolume}} \text{ and } \phi_{ads} = \frac{\text{AdsorbedVolume}}{\text{RockVolume}} \text{ and } S_{ads} = \frac{\text{AdsorbedVolume}}{\text{PoreVolume}}$$

The adsorbed saturation can therefore be calculated as follows:

$$S_{ads} = \frac{\phi_{ads}}{\phi}$$

From SPE 131772, ϕ_{ads} is defined as:

$$\phi_{ads} = 1.318 \times 10^{-6} M \left[\frac{V_L p_i}{p_i + p_L} \right] \frac{\rho_b}{\rho_{ads}}$$

where

ϕ_{ads} = Fractional volume occupied by adsorbed phase

M = Molecular weight of the gas (lbm/lbmole)

V_L = Langmuir Volume (scf/ton)

p_L = Langmuir Pressure (psi(a))

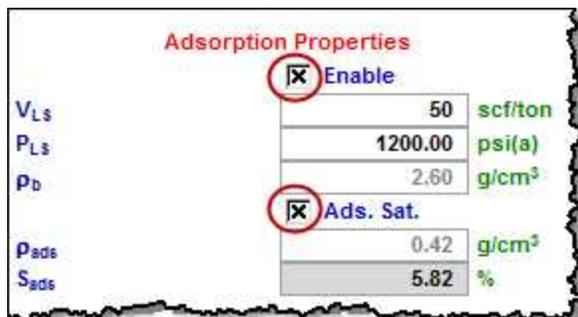
p_i = Initial reservoir pressure (psi(a))

ρ_b = Bulk density of the rock (g/cm³)

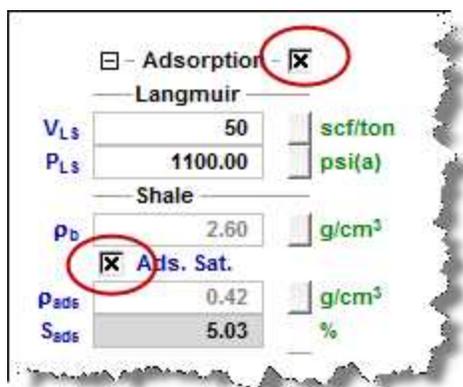
ρ_{ads} = Density of the adsorbed phase (g/cm³)

Note: ρ_{ads} is the density of the adsorbed “liquid” phase. The default in Harmony Enterprise for this value corresponds to the liquid methane density of 0.42 g/cm³.

The adsorption saturation correction is available for gas volumetric and gas analytical models. In gas volumetric analyses, the correction is available under Adsorption Properties. To use the correction, click the **Enable** checkbox and then the **Ads. Sat.** checkbox.



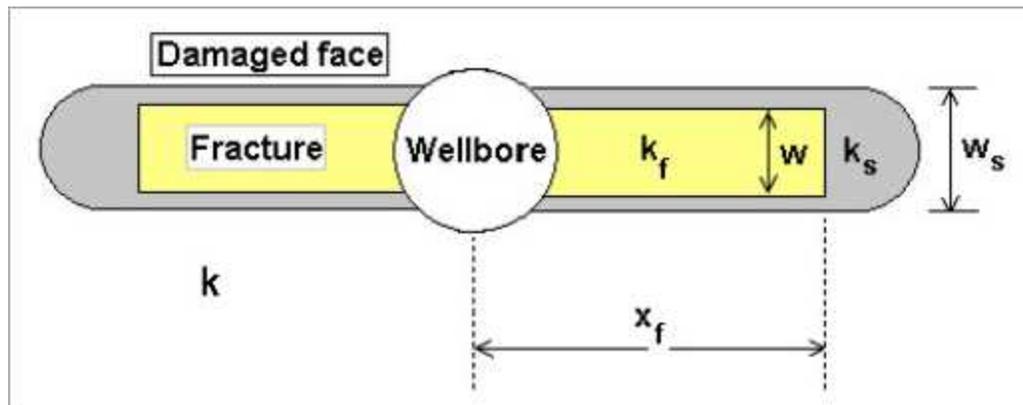
In gas analytical models, click the **Adsorption** checkbox, then click the **Ads. Sat.** checkbox.



Enabling the Ads. Sat. correction results in an adsorbed saturation (S_{ads}) being calculated, which in turn is subtracted from the original gas saturation (S_g). This corrected gas saturation is now used in the volumetric calculations to calculate a new free-gas OGIP.

Skin on fracture face (s_f)

When a hydraulic fracture is created, the interface between the fracture and the formation may encounter some permeability reduction either intentionally (leak-off additives) or unintentionally (for example, relative permeability effects, non-breaking gel). This is modeled by assuming the presence of a skin on the fracture face as shown below.



The skin on the fracture face causes an additional pressure drop that tends to negate some of the benefits of the fracture. Sometimes this skin on the fracture face improves with production or time (clean up or temperature effects). Cinco-Ley and Samaniego (1987 and 1981) have defined s_f as:

$$s_f = \frac{\pi w_s}{2X_f} \left(\frac{k}{k_s} - 1 \right)$$

Even a small skin on the fracture face, $s_f < 1$, can cause a substantial change in the shape of the derivative curve. Typically, s_f ranges from 0 to 1.

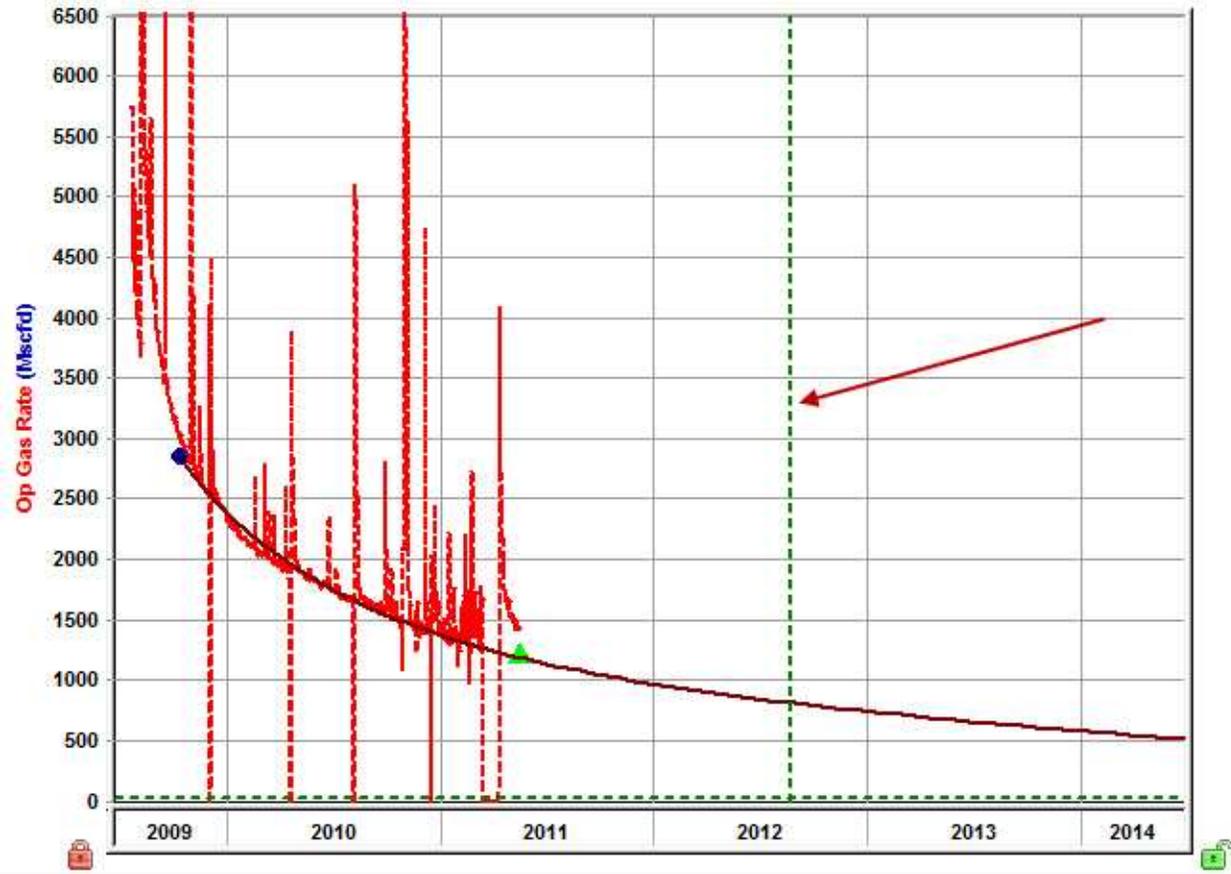
Terminal / limiting decline rate

The terminal / limiting decline rate begins as a hyperbolic decline curve and transitions into an exponential decline curve at a specified limiting effective decline rate, d_{lim} . When the **Terminal / Limiting Decline Rate** option is selected in the **Calc Method** drop-down menu, a d_{lim} value is required.

Analysis Parameters		
Rate Type	Op. Day	
Forecast Start Date	16/05/2011	DD/MM/YYYY
q	1577.6	Mscfd
d sec	12.176	%/year
b	1.000	
- Segment 1 -		
Calc Method	d _{lim} - Δt Q _r	
Start Date	19/06/2010	DD/MM/YYYY
q _i	1804.3	Mscfd
Q _i	777.866	MMscf
Δt	6000.000	month
a _i	0.159	/year
b	1.000	<input checked="" type="checkbox"/>
d _{lim} exp	Required	%/year
Q _r	22.5	Mscfd
End Date	23/06/2510	DD/MM/YYYY
ΔQ	18226.667	MMscf
Q _r	19004.532	MMscf

There are two options for the d_{lim} value: “ d_{lim} exponential” and “ d_{lim} hyperbolic”. When you click , it toggles to ; clicking the option again selects " d_{lim} exponential".

When using the “ d_{lim} exponential” option, the decline transitions such that the exponential portion of the decline has an effective decline rate of the d_{lim} value specified. When using the “ d_{lim} hyperbolic” option, the decline transitions when the hyperbolic portion reaches the specified d_{lim} value. The exponential portion then has an effective decline rate that is different from the d_{lim} value.



Note: The vertical dashed green line in the screenshot above indicates the transition from hyperbolic to exponential.

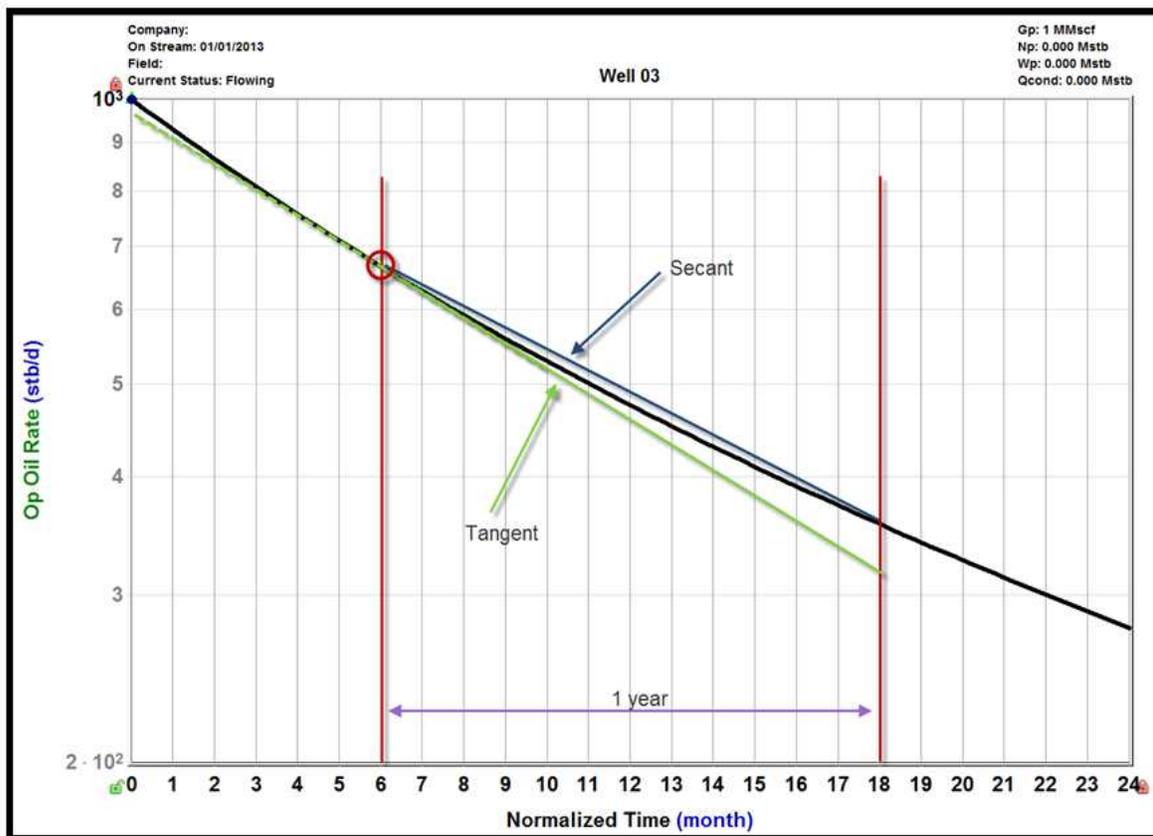
Terminal decline calculation methods

There are two ways to calculate the effective decline rate:

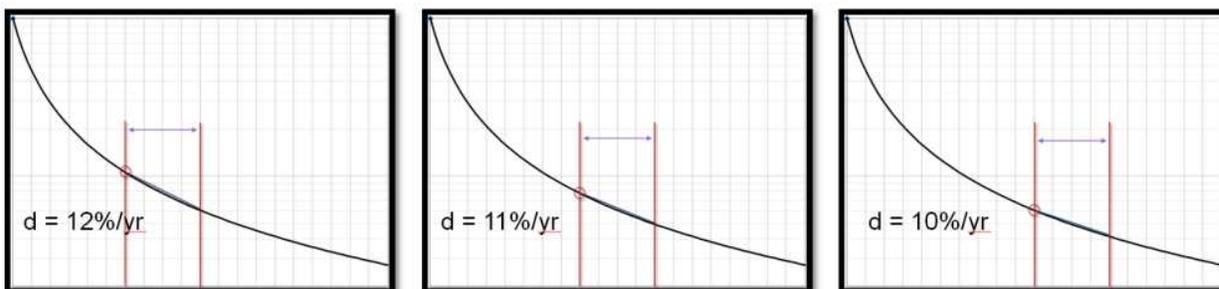
1. Secant
2. Tangent

All of the calculations go from your point of interest to a year ahead, but the difference is whether you are drawing a chord segment (secant line) or tangent line.

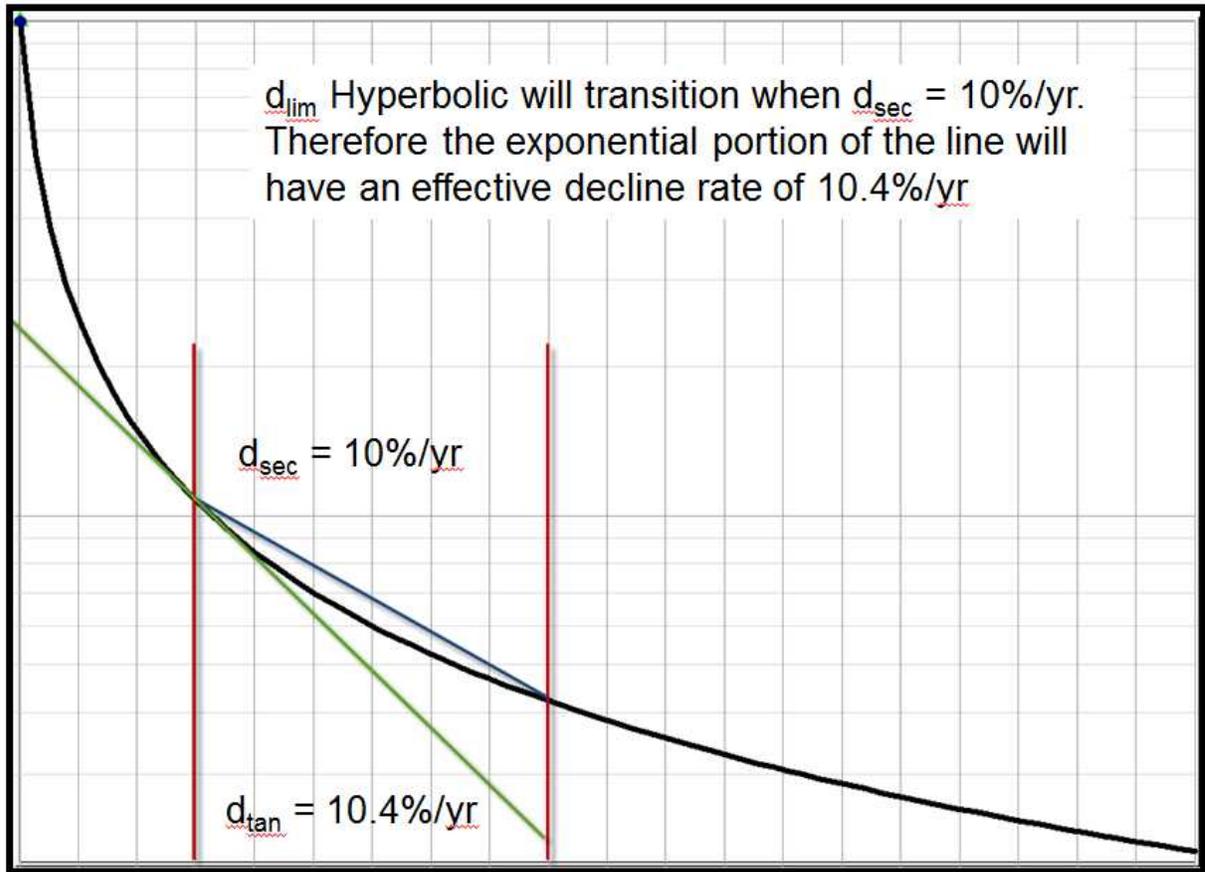
Note: The most common way to calculate the effective decline rate is by using the secant line, and because of this, references to the effective decline rate mean that the secant line is used.



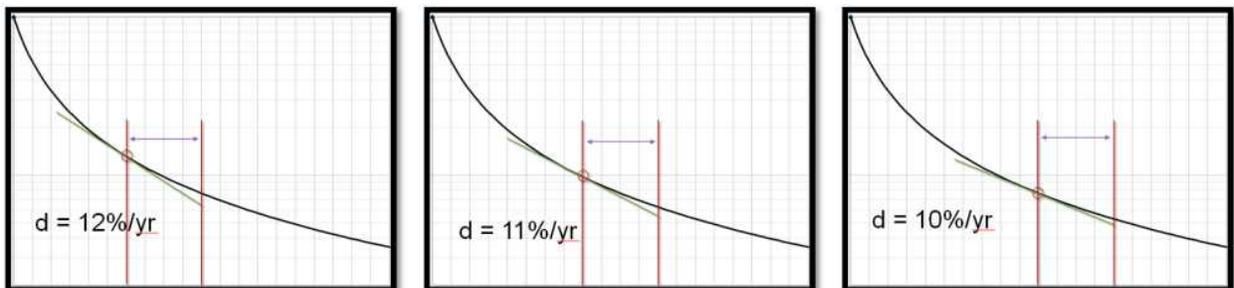
A d_{lim} hyperbolic uses the secant line to calculate the effective decline rate. If you want a d_{lim} hyperbolic of 10%, find where the 10% is calculated, and then switch from a hyperbolic decline to an exponential decline.



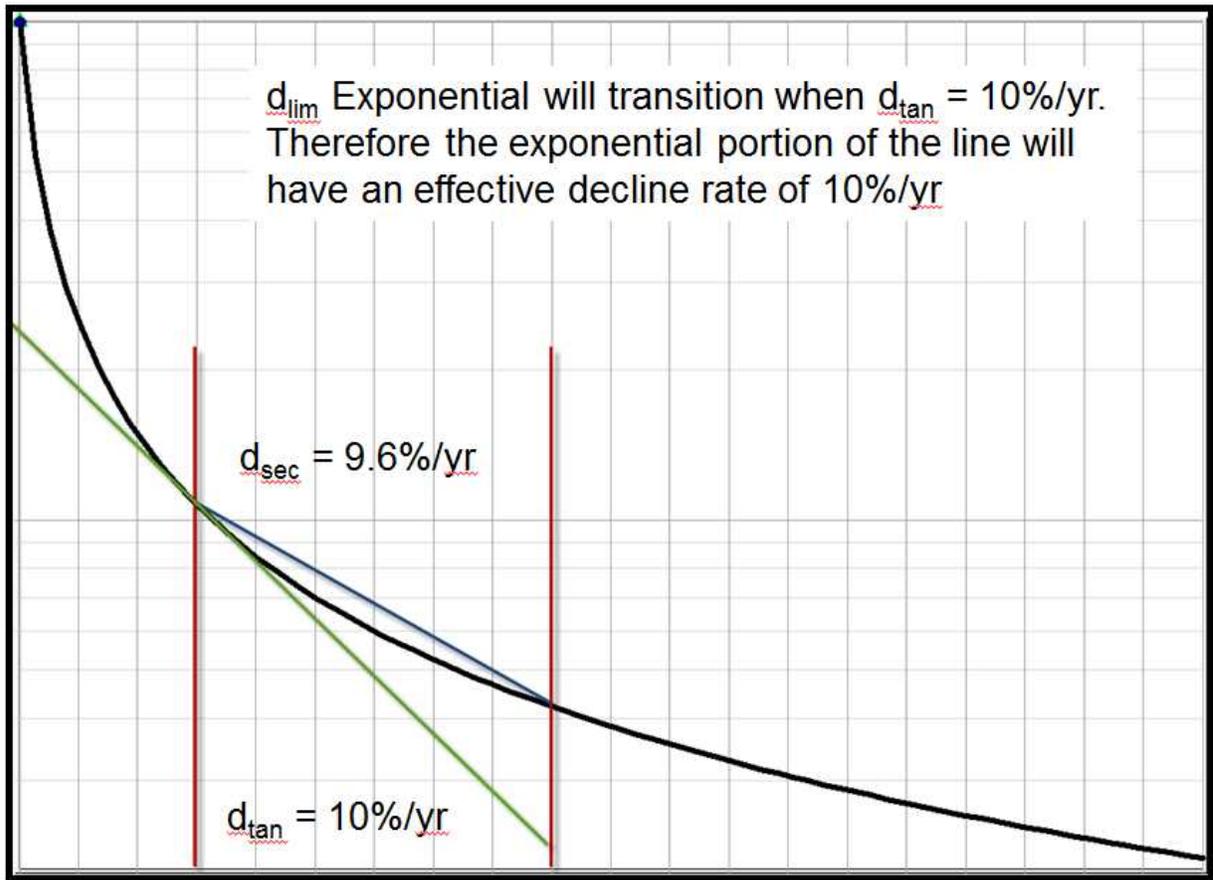
However, you cannot go from the hyperbolic to that chord segment line and expect a reasonable result. You need a smooth transition, so even though we used the chord segment to calculate the 10%, we need to use the tangent line to create the exponential section, which is not even 10%. This section is 10.4% for the remainder of the forecast.



The method described above used to be the default way of calculating terminal decline. Even though the secant / chord segment is how the effective decline rate is almost always calculated, when doing a d_{lim} , we use the tangent line.



The transition from hyperbolic to exponential is smooth, with an exponential portion that is actually 10%. This is now the default way to calculate terminal decline.



Time-dependent skin

Time-dependent skin accounts for wellbore skin changes with time, which can include a wide range of near-wellbore phenomena in production data, or pressure transient analysis. Some of these phenomena include:

- Pressure-dependent permeability (can also be handled explicitly using the modified pseudo-pressure method)
- Fracture closure over time
- Migration of fines through a fracture
- Condensate drop-out near the well
- Scale / wax deposition near perforations

- Well cleanup (decreasing skin damage)
- Gradual loss of formation integrity near the wellbore

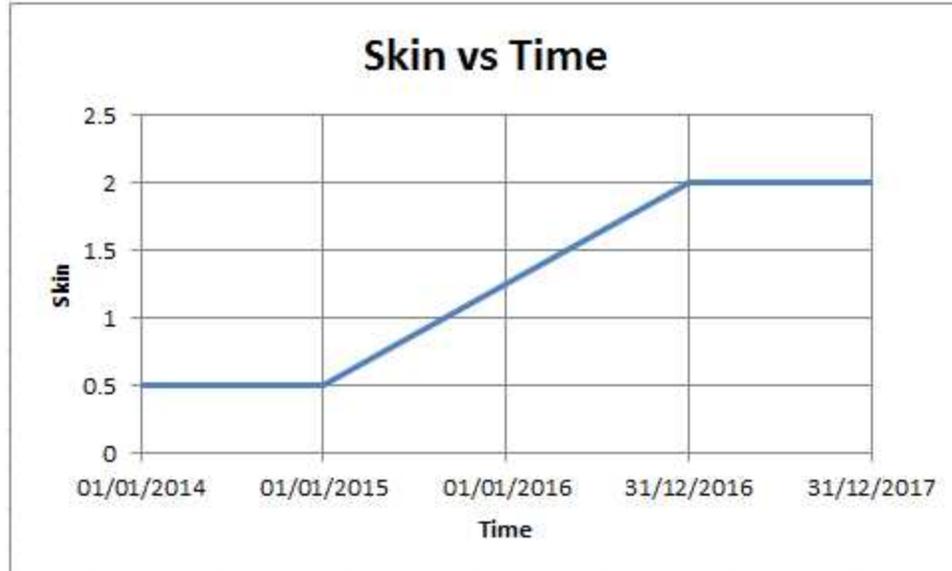
The processes occurring during these phenomena may be very complex and difficult to model analytically. The changing skin model is a suitable approximation because it "lumps" all the contributors of pressure loss into a single term, occurring at a discrete point (and thus, it is independent of the geometrical or fluid-flow complexities).

Time-dependent skin should be thought of as a "tuning parameter" during the history-matching phase of numerical modeling. It is designed to be a catch-all for any changing fluid or reservoir property over time that is *not* accommodated by the analytical model. In order to obtain a unique result, a simultaneous match on flowing and shut-in pressures is almost always required. In other words, flowing data on its own rarely shows a clear trend of changing well productivity (especially, if it is a decreasing damage over time). This is because the effect is usually masked by depletion. However, if shut-in pressures are used in conjunction with flowing data, the changing productivity can be clearly identified, as no "static" reservoir model is able to honor both data-sets.

The time-dependent skin has the following inputs:

- s or s_f (skin, or damage skin on fracture face) = the starting value of skin
- t_{sds} (skin damage start date) = the start date of changing skin
- t_{sde} (skin damage end date) = the end date of changing skin
- s_{lim} (skin damage limit) = the limit of changing skin (on and after the end date of changing skin)

For example, if the skin is initially 0.5, and the skin increases on $t_{sds} = 01/01/2015$ linearly to $s_{lim} = 2$ on 31/12/2016, and then the skin remains at 2, the numerical simulator takes into account such skin change as a function of time.



Time to stabilization

Time to stabilization (t_{stab}) is defined as the time it takes for the radius of investigation to reach all of the reservoir boundaries.

$$t_{stab} = \frac{(\text{distance to furthest boundary})^2 \cdot 948 \cdot \phi \mu c_t}{k}$$

Stabilization originated as a practical consideration and reflected the point at which pressure no longer changed significantly with time: that is, it had *stabilized*. With high-permeability reservoirs, this point was not difficult to observe. However, in tight formations, it takes a very long time for pressure to stabilize — often months, or even years. Moreover, except where there is a pressure maintenance mechanism acting on the pool, a true steady state is never achieved and pressure never becomes constant.

Water drive

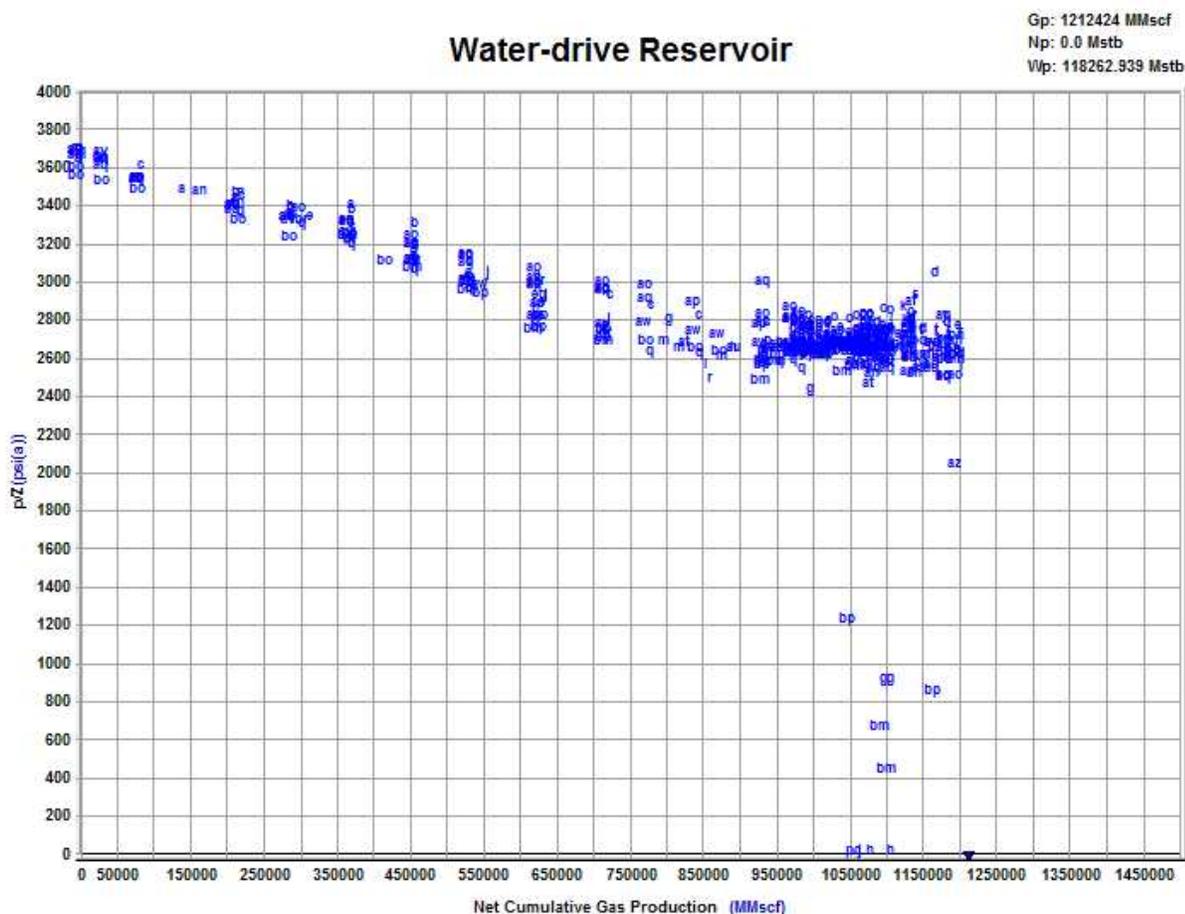
In Harmony Enterprise, there are three different water drive models that can be applied: a steady-state model, a pseudo-steady state model, and a transient model. However, these models can only be applied to specific analysis types, and the type of model that can be applied depends

on the analysis being performed. To reduce complexity, water drive theory is described in these topics:

- Water drive in Gas Material Balance (GMB)
- Water drive in typecurves, Flowing Material Balance (FMB) & Oil Material Balance (OMB)

Water drive in GMB

Some gas reservoirs may be connected to aquifers that provide pressure support to the gas reservoir as it is depleted. In this case, the pressure decrease in the gas reservoir is balanced by water encroaching into the reservoir. As this happens, the pore volume of gas is decreasing and the average reservoir pressure is maintained. Often this reservoir will show a flat pressure trend after some depletion. An example of this behavior on a p/Z plot is shown below.



The change in reservoir volume due to net encroached water can be determined from the following equation:

$$\Delta V_{wip} = 5.615(W_e - W_\rho B_w)$$

To use this in the material balance, the change in pore volume is taken relative to the initial pore volume, shown below.

$$C_{wip} = \frac{5.615 (W_e - W_\rho B_w)}{B_{gi} G / S_{gi}}$$

When dealing with this equation, the major unknown value to be determined is water encroachment from the aquifer (W_e). Two aquifer models are provided to determine net encroached water: Schilthuis Steady-State model and Fetkovich model.

Schilthuis steady-state model

This is the simplest aquifer model and assumes that the rate of water influx is proportional to pressure drawdown. In this model, it is assumed that the aquifer volume is much larger than the gas reservoir and remains at the initial pressure.

$$W_e = K \int_0^t (p_i - p) dt = K \sum_{j=0}^n \left(p_i - \frac{p_j + p_{j-1}}{2} \right) (t_j - t_{j-1})$$

Using this model, the only parameter to solve for is the transfer coefficient (J).

Fetkovich

In the Fetkovich aquifer, the aquifer is assumed to be in pseudo-steady state and depleted according to the material balance equation. In this model, both the aquifer volume and transfer coefficient must be determined. The equations are shown below.

$$W_e = K \int_0^t (p_i - p) dt = K \sum_{j=0}^n \left(p_i - \frac{p_j + p_{j-1}}{2} \right) (t_j - t_{j-1})$$

$$W_{ei} = c_w p_{aqi} V_{aq}$$

$$J = \frac{k h}{141.2\mu \left(\ln \frac{r_e}{r_o} - \frac{3}{4} \right)} \frac{\theta}{360}$$

While the transfer coefficient is defined, the required inputs to calculate the transfer coefficient are often not known. More commonly the transfer coefficient is determined as part of matching the p/Z plot.

Water drive in typecurves, FMB & OMB

Click to see subtopics / related topics:

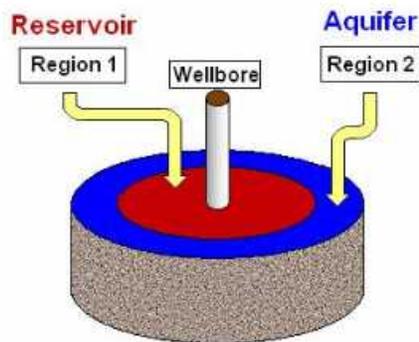
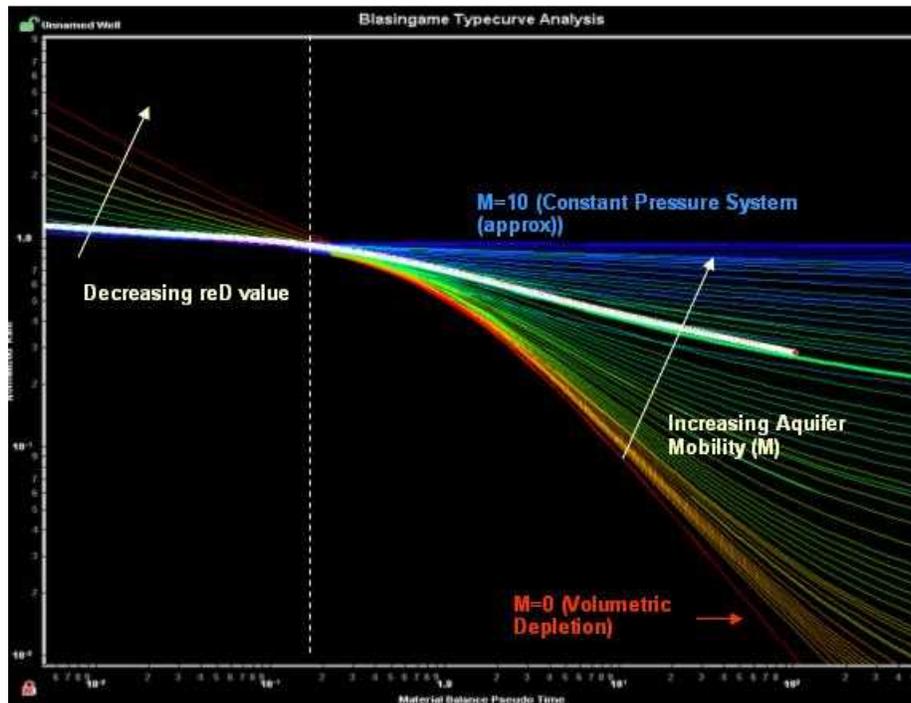
This topic describes the general theory and application of transient and pseudo-steady state (PSS) water-drive concepts in Harmony Enterprise. Since the Gas Material Balance (GMB) analysis can also use a steady-state equation (Schilthuis), this is described in [water drive in GMB](#).

Transient Water-drive model

The transient water-drive model consists of dimensionless typecurves, implemented in Blasingame, Agarwal-Gardner and the normalized pressure integral (NPI). The typecurve model has the following characteristics:

- Assumes an infinite acting aquifer with a stationary boundary
- Assumes a radial edge water-drive system (radial composite model)
- Ideal for very large aquifers of low to medium mobility
- Designed for early-time analysis, as it is a pressure transient model
- Water influx is not calculated, reservoir material balance is not corrected

The dimensionless typecurves and definitions are shown below.



Mobility Ratio (M):

$$M = \frac{M_{aq}}{M_{res}} = \frac{k_{aq} \mu_{res}}{k_{res} \mu_{res}}$$

The typecurves are based on a radial composite model, with the outer region representing the aquifer. With typecurves you can match production data to typecurve models characterized by several different levels of aquifer mobility, relative to the reservoir. The mobility ratios range from zero (no aquifer) to ten (effectively constant pressure boundaries). The aquifer model assumes a water zone of infinite extent. Thus, by matching to the water-drive typecurves you can determine the oil / gas –in-place, as well as "aquifer strength" in the form of a mobility ratio (the

aquifer permeability is also calculated based on an assumed water viscosity). The practicality of estimating hydrocarbon volumes using water-drive typecurves is a strong function of, among other things, mobility ratio. The closer the mobility ratio is to one (1), the more difficult it is to identify the outer boundary of the reservoir, and thus the gas- / oil-in-place

The typecurves assume single-phase production from the reservoir, and a stationary reservoir / aquifer interface. For many active water-drive systems prior to water breakthrough, this is thought to be a reasonable approximation.

Aquifer typecurve matching is performed in much the same way as that of the volumetric models. If the data contains enough character to show the transition from the reservoir zone to the water bearing zone, the hydrocarbons-in-place can be estimated effectively. The success of the methodology depends on there being a clearly identifiable transition region, which is not the case if the mobility ratio is close to one. With the aquifer typecurves, the user must choose both a transient (dimensionless reservoir radius) stem and an Aquifer Mobility stem.

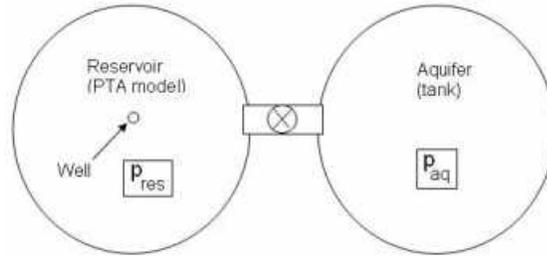
Pseudo-Steady State Water-drive model

The pseudo-steady state (PSS) water influx model is based on work by Fetkovich et al. It is implemented in the Blasingame, Agarwal-Gardner, FMB and NPI methods. The model characteristics are as follows.

- Assumes finite aquifer, modeled as a tank
- Assumes a geometry-independent-transfer coefficient (productivity index) that prescribes how much water flows between the aquifer and reservoir
- Ideal for limited aquifers of medium to high mobility
- Designed for *early-time* analysis, prior to water breakthrough
- Water influx is calculated, reservoir material balance includes the effect of water influx

The conventional use of the PSS water-drive model is in history matching P/Z data from gas reservoirs. In Harmony Reservoir, its implementation is for the flowing well problem (not static data). A schematic of the model is shown below.

The objective of the model is to simultaneously solve the aquifer influx equation with the material-balance equation for the reservoir. For more information, see XREF Material Balance Time for Water-drive Reservoirs and XREF Calculation of Reservoir Pressure and Water Influx for a Reservoir Under Active Water Drive.



The implementation of the PSS method involves a process called inverse modeling. This process uses the standard (volumetric) typecurves as a base model and subtracts the water influx effect from the data, so as to collapse the production response (q / Dp vs. tca) back onto the base type-curve. It is clear that the aquifer effect must be apparent in the data for the inverse modeling procedure to be effective.

The key matching parameters in the PSS model are the initial water-in-place (IWIP) and the aquifer productivity index (PI).

Material balance time for water-drive reservoirs

Oil reservoirs (undersaturated)

Starting with a general (undersaturated) oil material balance (including water influx):

$$N_p B_o = N B_{oi} \left(c_o (p_i - \bar{p}) + \frac{c_w S_w + c_f}{S_o} (p_i - \bar{p}) \right) + W_e B_w \quad (1)$$

Rearranging equation (1) and dividing both sides by q :

$$\frac{p_i - \bar{p}}{q} = \frac{N_p B_o - W_e B_w}{N B_{oi} c_e q} \quad (2)$$

where:

$$c_e = c_o + \frac{c_w S_w + c_f}{S_o} \quad (3)$$

The PSS equation for oil, written in terms of material balance time is as follows:

$$\frac{p_i - \bar{p}}{q} = \frac{t_c}{N c_e} \quad (4)$$

Comparing equations (2) and (4), we see that:

$$t_c = \frac{N_p B_o - W_e B_w}{B_{oi} q}$$

Gas reservoirs

For gas reservoirs, there are two non-linearities that exist:

- Compressibility factor (Z) and viscosity (μ) vs. reservoir pressure (p)
- Compressibility (c) and viscosity vs. time

In order to use the PSS equation for gas, these non-linearities must be linearized. For compressibility factor vs. reservoir pressure, this is done using pseudo-pressure (pp). For compressibility vs. time, this is done using pseudo-time (ta). Thus, we want to derive a form of the PSS equation that utilizes pseudo-pressure and pseudo-time.

Starting with a general form of the gas material balance (including water influx):

$$\frac{\bar{p}}{\bar{Z}} = \frac{\frac{p_i}{Z_i} \left(1 - \frac{G_p}{G}\right)}{1 - c_o(p_i - \bar{p}) - E_{gi} \frac{W_e}{G}} \quad (5)$$

where:

$$E_{gi} = \frac{V_{sc}}{V_i} = \frac{p_i}{p_{sc}} \frac{T_{sc}}{T_i} \frac{Z_{sc}}{Z_i}$$

The definition of pseudo-pressure is:

$$\bar{\psi}(\bar{p}) = 2 \int_0^{\bar{p}} \frac{\bar{p} dp}{\bar{\mu} \bar{Z}} \quad (6)$$

In order to get to the PSS equation for gas, we can use the chain rule as follows:

$$\frac{\partial \psi}{\partial t} = \frac{\frac{\partial}{\partial t} \left(\frac{\bar{p}}{\bar{Z}} \right) * \frac{\partial \psi}{\partial \bar{p}}}{\frac{\partial}{\partial \bar{p}} \left(\frac{\bar{p}}{\bar{Z}} \right)} \quad (7)$$

The first term in the numerator of (7) is calculated as follows:

$$\begin{aligned} \frac{\partial}{\partial t} \left(\frac{\bar{p}}{\bar{Z}} \right) &= -\frac{p_i}{Z_i} \frac{q}{G} \left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G} \right]^{-1} \\ &\quad - \frac{p_i}{Z_i} \left[1 - \frac{G_p}{G} \right] \left[c_e \frac{\partial p}{\partial t} - \frac{E_{gi}}{G} q_{we} \right] \left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G} \right]^{-2} \end{aligned} \quad (8)$$

Recognizing that:

$$\frac{\partial \psi}{\partial t} = \frac{\partial \psi}{\partial p} \frac{\partial p}{\partial t} \quad (9)$$

where, from the definition of pseudo-time:

$$\frac{\partial \psi}{\partial p} = \frac{2\bar{p}}{\bar{\mu}\bar{Z}} \quad (10)$$

Combining equations (9) and (10), we get:

$$\frac{\partial \bar{p}}{\partial t} = \frac{\partial \psi}{\partial t} \frac{\bar{\mu}\bar{Z}}{2\bar{p}} \quad (11)$$

The denominator of (7) is calculated as follows:

$$\begin{aligned} \frac{\partial}{\partial \bar{p}} \left(\frac{\bar{p}}{\bar{Z}} \right) &= \bar{p} \frac{\partial}{\partial \bar{p}} \left(\frac{1}{\bar{Z}} \right) + \frac{1}{\bar{Z}} = -\frac{\bar{p}}{\bar{Z}^2} \frac{\partial \bar{Z}}{\partial \bar{p}} + \frac{1}{\bar{Z}} = \frac{1}{\bar{Z}} \left[1 - \frac{\bar{p}}{\bar{Z}} \frac{\partial \bar{Z}}{\partial \bar{p}} \right] = \frac{\bar{p}}{\bar{Z}} \left[\frac{1}{\bar{p}} - \frac{1}{\bar{Z}} \frac{\partial \bar{Z}}{\partial \bar{p}} \right] \\ &= \frac{\bar{p}}{\bar{Z}} * \bar{c}_g \end{aligned} \quad (12)$$

Substituting equation (11) into (8) and equations (12), (10) and (8) into (7), collecting like terms, and simplifying, we get:

$$\frac{\partial \psi}{\partial t} = \frac{\frac{2p_i}{\bar{\mu}} \frac{\bar{p}}{G} \left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G} \right] \left[-q + \frac{E_{gi} q_{we} \left[1 - \frac{G_p}{G} \right]}{\left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G} \right]} \right]}{p_i \left[1 - \frac{G_p}{G} \right] c_e \bar{Z} + \bar{c}_g Z_i \bar{p} \left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G} \right]} \quad (13)$$

From equation (5), we see that:

$$\left(1 - \frac{G_p}{G}\right) = \frac{Z_i}{p_i} \left(\frac{\bar{p}}{\bar{Z}}\right) \left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G}\right] \quad (14)$$

Substituting equation (14) into (13) and simplifying, we get:

$$\frac{\partial \psi}{\partial t} = \frac{2p_i}{Z_i \bar{\mu} G} \frac{\left(-q + E_{gi} q_{we} \frac{Z_i \bar{p}}{p_i \bar{Z}}\right)}{c_e + c_g \left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G}\right]} \quad (15)$$

Integrating both sides of (15) with respect to dt, we get:

$$\int_{\psi_i}^{\bar{\psi}} d\psi = \frac{2p_i}{Z_i \bar{\mu} G} \int_0^t \frac{\left(-q + E_{gi} q_{we} \frac{Z_i \bar{p}}{p_i \bar{Z}}\right)}{c_e + c_g \left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G}\right]} dt \quad (16)$$

$$\psi_i - \bar{\psi} = \frac{2p_i}{Z_i G} \int_0^t \frac{(q - E_{gi} q_{we})}{\mu \bar{c}_{te}} dt \quad (17)$$

where:

$$\bar{c}_{te} = c_e + c_g \left[1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G}\right] \quad (18)$$

To linearize equation (17), we define pseudo-time as:

$$t_{ca} = \frac{(\mu c_t)_i}{q} \int_0^t \frac{(q - E_{gi} q_{we})}{\bar{\mu} \bar{c}_{te}} dt \quad (19)$$

Now, equation (17) is rewritten as:

$$\frac{\psi_i - \bar{\psi}}{q} = \frac{2p_i}{(\mu c_t)_i Z_i G} t_{ca} \quad (20)$$

An alternate form of pseudo-time may be calculated without having to do the numerical integration in (19). It is defined using equation (20) as:

$$t_{ca} = \frac{(\mu c_t)_i Z_i G}{2 p_i} \left[\frac{\psi_i - \bar{\psi}}{q} \right] \quad (21)$$

Calculation of reservoir pressure & water influx for a reservoir under active water drive

Oil reservoirs (undersaturated)

The Fetkovich water influx equation is as follows:

$$W_e = \frac{W_{ei}}{p_i} (p_i - \bar{p}) \left(1 - e^{-J p_i t / W_{ei}} \right) \quad (22)$$

where:

$$W_{ei} = \text{Initial Encroachable Water} = IWIP * p_i * c_w$$

Transfer coefficient / influx equation:

$$J = \frac{f k h}{141.2 \mu \left[\ln \frac{r_e}{r_o} - \frac{3}{4} \right]} \quad (23)$$

$$f = \frac{\text{encroachment angle}}{360^\circ}$$

The oil material balance equation (including water influx) is as follows:

$$N_p B_o = N B_{oi} \left(c_o (p_i - \bar{p}) + \frac{c_w S_w + c_f}{S_o} (p_i - \bar{p}) \right) + W_e B_w \quad (24)$$

Rearranging (24):

$$p_i - \bar{p} = \frac{N_p B_o - W_e B_w}{N B_{oi} c_e} \quad (25)$$

where:

$$c_e = c_o + \frac{c_w S_w + c_f}{S_o} \quad (26)$$

The aquifer material-balance equation is as follows:

$$p_{aq} = p_i \left[1 - \frac{W_e}{W_{ei}} \right] \quad (27)$$

In order to solve for water influx and reservoir pressure, equations (22), (25) and (27) are discretized in time:

Aquifer Material Balance:

$$p_{aq_{n-1}} = p_i \left[1 - \frac{W_{e_{n-1}}}{W_{ei}} \right] \quad (28)$$

Water Influx:

$$\Delta W_{e_n}^k = \frac{W_{ei}}{p_i} (p_{aq_{n-1}} - \frac{1}{2} (\bar{p}_{n-1} + \bar{p}_n^k)) \left(1 - e^{-J p_i \Delta t / W_{ei}} \right) \quad (29)$$

$$W_{e_n}^k = \sum_{j=1}^{n-1} \Delta W_{e_j} + \Delta W_{e_n}^k \quad (30)$$

Reservoir Material Balance:

$$p_i - \bar{p}_n^k = \frac{N_{p,n} B_o - W_{e_n}^k B_w}{N B_{oi} c_e} \quad (31)$$

An alternative method for solving the water influx problem is to use a different form of the influx equation, which accounts for the aquifer material balance intrinsically, and does not assume a constant pressure difference between aquifer and reservoir. This form of the influx equation assumes a constant rate of water influx:

$$p_i - \bar{p} = \frac{p_i W_e}{W_{ei}} + \frac{q_w}{J} \quad (32)$$

where q_w = the rate of water influx.

Discretizing equation (32), we get:

$$p_i - \bar{p}_n^k = \frac{p_i W_e}{W_{ei}} + \frac{W_{e_n}^k - W_{e_{n-1}}}{J \Delta t} \quad (33)$$

Solving (33) and (31) simultaneously, we get:

$$\frac{p_i W_{e_n}^k}{W_{ei}} + \frac{W_{e_n}^k - W_{e_{n-1}}}{J \Delta t} = \frac{N_{p,n} B_o - W_{e_n}^k B_w}{N B_{oi} c_e} \quad (34)$$

Simplifying the above, and including the reservoir material balance, we get:

Aquifer Material Balance + Water Influx

$$W_{e_n}^k = \left(\frac{N_{p,n} B_o}{N B_{oi} c_e} - \frac{W_{e_{n-1}}}{J \Delta t} \right) \left(\frac{p_i}{W_{ei}} + \frac{1}{J \Delta t} + \frac{B_w}{N B_{oi} c_e} \right)^{-1} \quad (35)$$

Reservoir Material Balance

$$p_i - \bar{p}_n^k = \frac{N_{p,n} B_o - W_{e_n}^k B_w}{N B_{oi} c_e} \quad (36)$$

Gas reservoirs

The same influx equations as above also apply to gas reservoirs, except the gas material-balance equation is used, instead of oil.

$$\frac{\bar{p}}{\bar{Z}} = \frac{\frac{p_i}{Z_i} \left(1 - \frac{G_p}{G}\right)}{1 - c_e(p_i - \bar{p}) - E_{gi} \frac{W_e}{G}} \quad (37)$$

The Fetkovich equations are as follows:

Aquifer Material Balance:

$$p_{aq_{n-1}} = p_i \left[1 - \frac{W_{e_{n-1}}}{W_{ei}}\right] \quad (38)$$

Water Influx:

$$\Delta W_{e_n}^k = \frac{W_{ei}}{p_i} \left(p_{aq_{n-1}} - \frac{1}{2} (\bar{p}_{n-1} + \bar{p}_n^k) \right) \left(1 - e^{-J p_i \Delta t / W_{ei}} \right) \quad (39)$$

$$W_{e_n}^k = \sum_{j=1}^{n-1} \Delta W_{e_j} + \Delta W_{e_n}^k \quad (40)$$

Reservoir Material Balance:

$$\left(\frac{\bar{p}}{\bar{Z}}\right)_n^k = \frac{\frac{p_i}{Z_i} \left(1 - \frac{G_{p_n}}{G}\right)}{1 - c_e(p_i - \bar{p}_n^k) - E_{gi} \frac{W_{e_n}^k}{G}} \quad (41)$$

The modified influx equations are as follows:

Aquifer Material Balance + Water Influx

$$W_{e_n}^k = \left[p_i - \bar{p}_n^k + \frac{W_{e_{n-1}}}{J \Delta t} \right] \left[\frac{p_i}{W_{ei}} + \frac{1}{J \Delta t} \right]^{-1} \quad (42)$$

Reservoir Material Balance:

$$\left(\frac{\bar{p}}{\bar{z}}\right)_n^k = \frac{\frac{p_i}{Z_i} \left(1 - \frac{G_{p_n}}{G}\right)}{1 - c_e(p_i - \bar{p}_n^k) - E_{gi} \frac{W_{e_n}^k}{G}} \quad (43)$$

Aquifer productivity index

Radial Edge Water Drive

$$J = \frac{k_{aq} h}{141.2 \mu_a \left(\ln \frac{r_{aq}}{r_e} - \frac{3}{4}\right)} \quad (44)$$

where:

$$r_{aq} / r_e \gg 1$$

Mobility Ratio (M) can be calculated as follows:

$$M = \frac{k_{aq} \mu_{res}}{\mu_{aq} k_{res}} = \frac{141.2 J}{h} \left(\ln \left[\sqrt{\frac{5.615 B_{wi} IWIP}{\pi \phi h r_e^2}} + 1 \right] - \frac{3}{4} \right) \frac{\mu_{res}}{k_{res}} \quad (45)$$

For all r_{aq} / r_e values, the following more rigorous derivation is applicable:

$$J = \frac{k_{aq} h}{141.2 \mu_{aq}} \left[\frac{1}{2(r_{ad}^2 - 1)} - \frac{(3r_{ad}^4 - 4r_{ad}^4 \ln r_{ad} - 2r_{ad}^2 - 1)}{4(r_{ad}^2 - 1)^2} \right]^{-1} \quad (46)$$

where:

$$r_{ad} = \frac{r_{aq}}{r_e} = \sqrt{\frac{5.615 B_{wi} IWIP}{\pi \phi h r_e^2} + 1} \quad (47)$$

now:

$$M = \frac{k_{aq} \mu_{res}}{\mu_{aq} k_{res}} = \frac{141.2 J}{h} \left[\frac{1}{2(r_{ad}^2 - 1)} - \frac{(3r_{ad}^4 - 4r_{ad}^4 \ln r_{ad} - 2r_{ad}^2 - 1)}{4(r_{ad}^2 - 1)^2} \right] \frac{\mu_{res}}{k_{res}} \quad (48)$$

Well linking logic

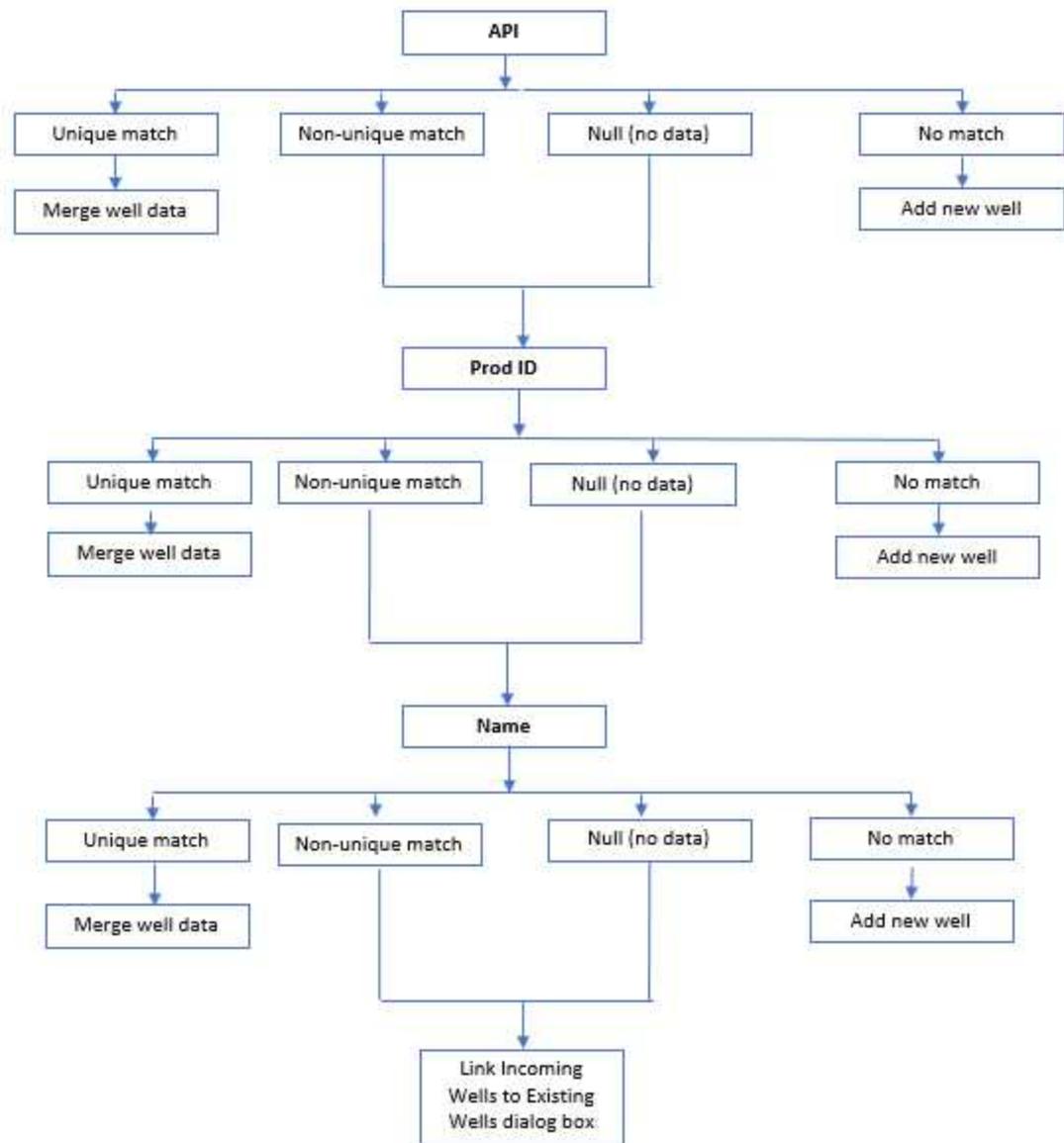
Well linking logic includes the following:

- General logic
- Harmony import logic
- Well Identifier special cases
- Enerdeq (split by Prod ID)
- Enerdeq special case
 - Enerdeq (do not split by Prod ID)

General well linking logic

Entity Header fields (excluding custom headers) in the Attributes tab are used to determine if incoming well data should be merged with existing wells in the Harmony Enterprise project, or added as new wells. The well linking / merging logic is described below. In this example, API, Prod ID, and Well Name are the Entity Header fields used for linking. However, any of the nine standardized Entity Header fields can be used. You can select between one and nine Entity Header fields using the well linking settings.

Note: In the following figure, null refers to the absence of data in the incoming well and not the existing well(s) in Harmony Enterprise.



For more information, see the [Link Incoming Wells to Existing Wells dialog box](#).

Exceptions

These are exceptions to the general logic:

- The Entity ID is always compared first, and if there is a match, the well is linked to it

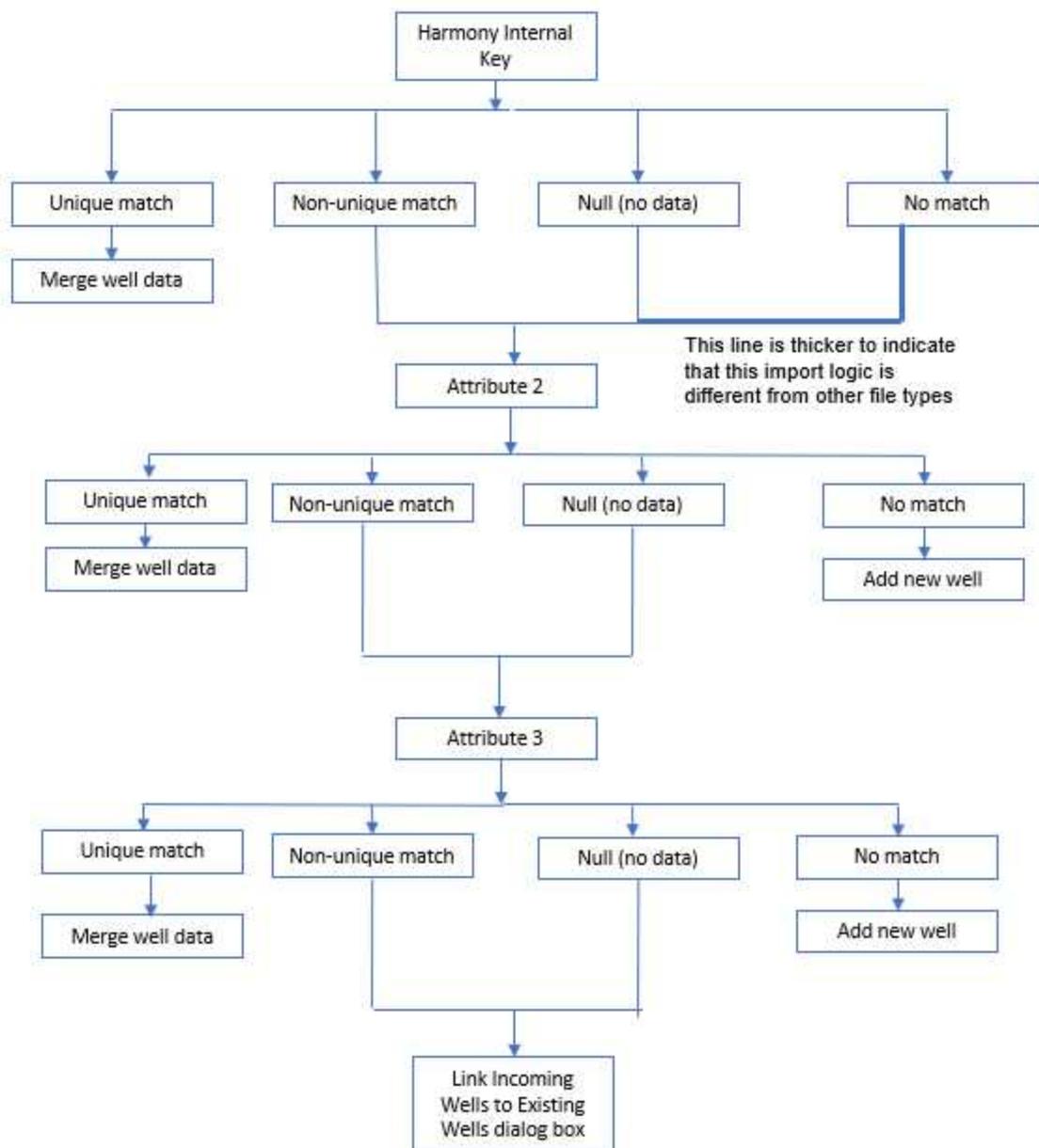
- Meter stations can only match to meter stations, even if all linking criteria indicates otherwise (except for the Entity ID, in which case, the well is linked).
- If the incoming well has an Entity ID (for example, an .hldb file import has it), but the well with the same Entity ID already in the database *has no access because of well-based security*, then an error is displayed (that is, well inaccessible) and the well is skipped.
- If any of the linking attributes have a character limit that is exceeded by an incoming well, the well is skipped.
 - All entity header attributes have finite character limits enforced by the Harmony database, *except* Prod ID, which has no limit.
- Linking attributes are determined as follows:
 - For Production, Static Pressure, and Attribute text imports, attributes are determined as described in [Well Identifier special cases](#).
 - For other attributes, we use the [Well Linking](#) settings in the Options dialog box.

Note: Enerdeq follows slightly different logic. For more information, see [Enerdeq special case](#).

Harmony import logic

Import logic from .hldb files is as follows:

Note: In the following figure, null refers to the absence of data in the incoming well and not the existing well(s) in Harmony Enterprise.



Well Identifier special cases

There are special rules for the Well Identifier with respect to production, static pressure, or attribute text imports.

Production text imports

You can specify Entity Header attributes for well linking. These attributes are also updated in the well, regardless of whether they were used for linking.

Import rules are as follows:

- If no well identifier is specified, the Link Incoming Wells to Existing Wells dialog box is always displayed.
- If a well identifier is specified, we use a combination of the Well Identifier and whichever entity header elements are specified. The Well Identifier gets compared first, then the rest of the available attributes are compared in the order specified in the options dialog box.

Static pressure text imports

These imports only use the Well Identifier.

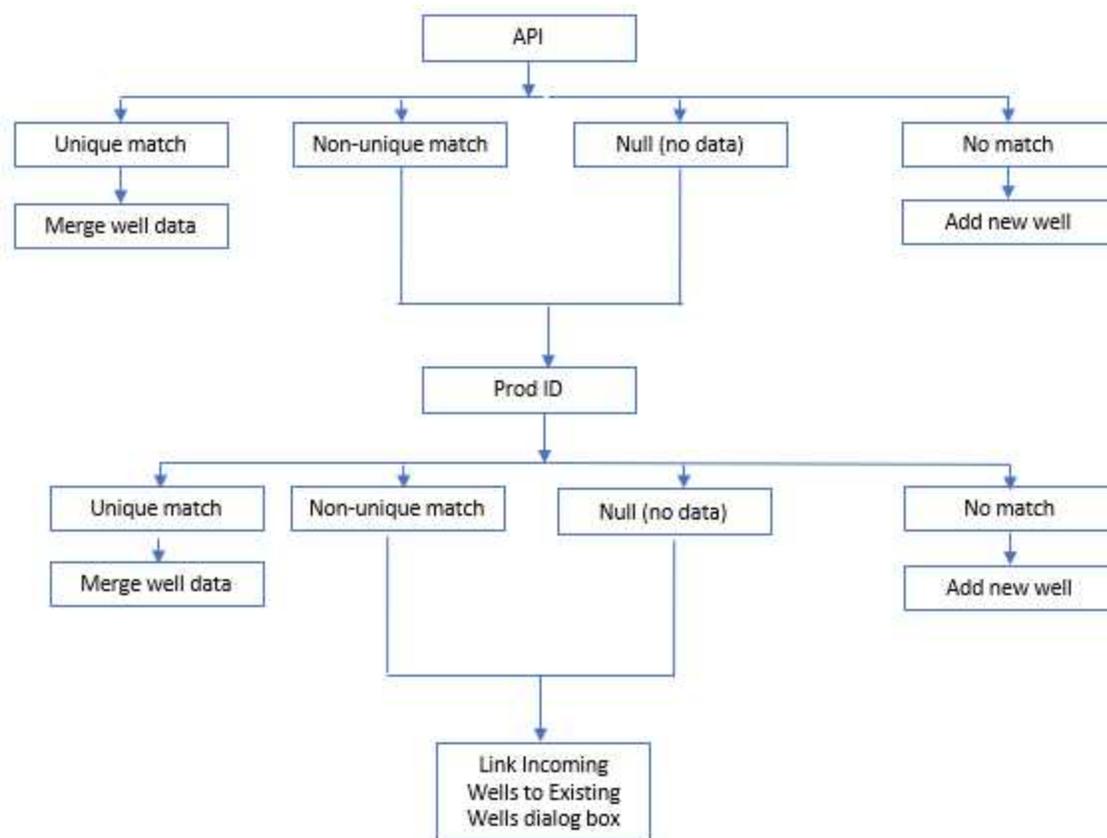
Attribute text imports

Entity Header attributes are not used for matching. These imports must uniquely match using the Well Identifier.

Enerdeq: split by Prod ID

The logic for Enerdeq that splits by Prod ID is as follows:

Note: In the following figure, null refers to the absence of data in the incoming well and not the existing well(s) in Harmony Enterprise.



Enerdeq special case

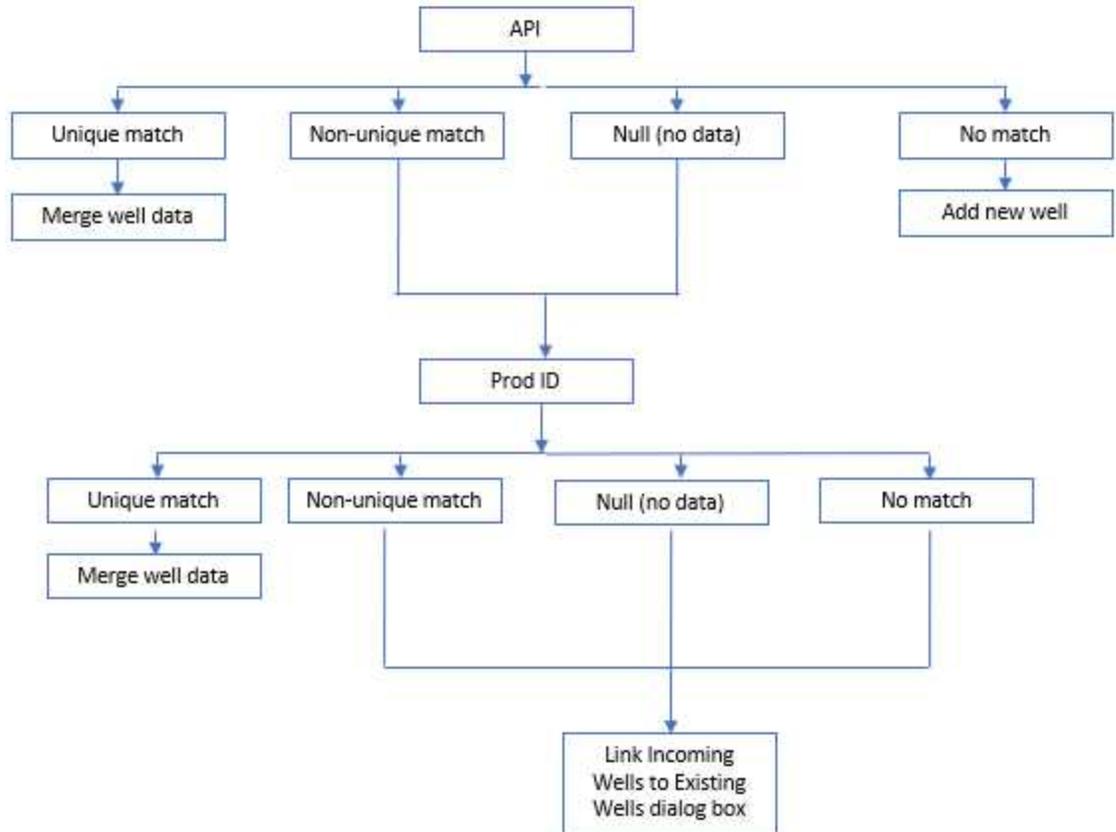
Enerdeq's default attributes for importing are API Number and Prod ID, which cannot be edited.

However, there is a special case when the user decides to *not* split by Prod ID using Enerdeq's options. In this case, the Link Incoming Wells to Existing Wells dialog box opens, even if there are no matches on the Prod ID. For more information, see Enerdeq (do not split by Prod ID).

Enerdeq: not split by Prod ID

If the user decides to not split by Prod ID, the logic for Enerdeq is as follows:

Note: In the following figure, null refers to the absence of data in the incoming well and not the existing well(s) in Harmony Enterprise.



Wellbore storage

Changing wellbore storage occurs when one of the following conditions exists within the wellbore:

- Changing wellbore fluid compressibility
- Phase redistribution
- Change in the type of storage from a changing liquid level to a liquid filled wellbore

The phenomenon of phase redistribution occurs in a well which is shut in at the surface with gas and liquid flowing simultaneously into the tubing. In these situations, the gravity effects cause the liquid to fall and the gas to rise to the surface. Because of the very low compressibility of liquid and no extra room for gas to expand in a closed chamber, the re-distribution of phases causes a net increase in the wellbore pressure. When the phenomenon is present in a buildup

test, the extra pressure surge in the wellbore is relieved through the formation. Eventually, equilibrium will be attained between the wellbore pressure and the formation pressure adjacent to the wellbore. However, at early times, the wellbore pressure may exceed the formation pressure causing an anomalous hump in the buildup pressure which cannot be analyzed in a conventional way with only the dimensionless wellbore storage constant (C_D). In order to deal with phase re-distribution, two models have been proposed by Fair (1981) and Hegeman et al. (1993) which introduce two additional dimensionless wellbore constants: apparent storage (C_{aD}) and the pressure parameter (C_{pD}).

Fair considered the exponential expression for the dimensionless anomalous pressure (p_{pD}) rise as:

$$P_{pD} = C_{pD} (1 - e^{-t_D/\alpha_D})$$

Later, Hegeman et al. showed that the negative C_{pD} values in the Fair model can be used for buildup data that has an anomalous pressure decrease. Therefore, for these wells, they argued that using an error function to model the anomalous pressure may allow for better modeling of field data with increasing or decreasing storage. Thus, Hegeman et al. proposed that:

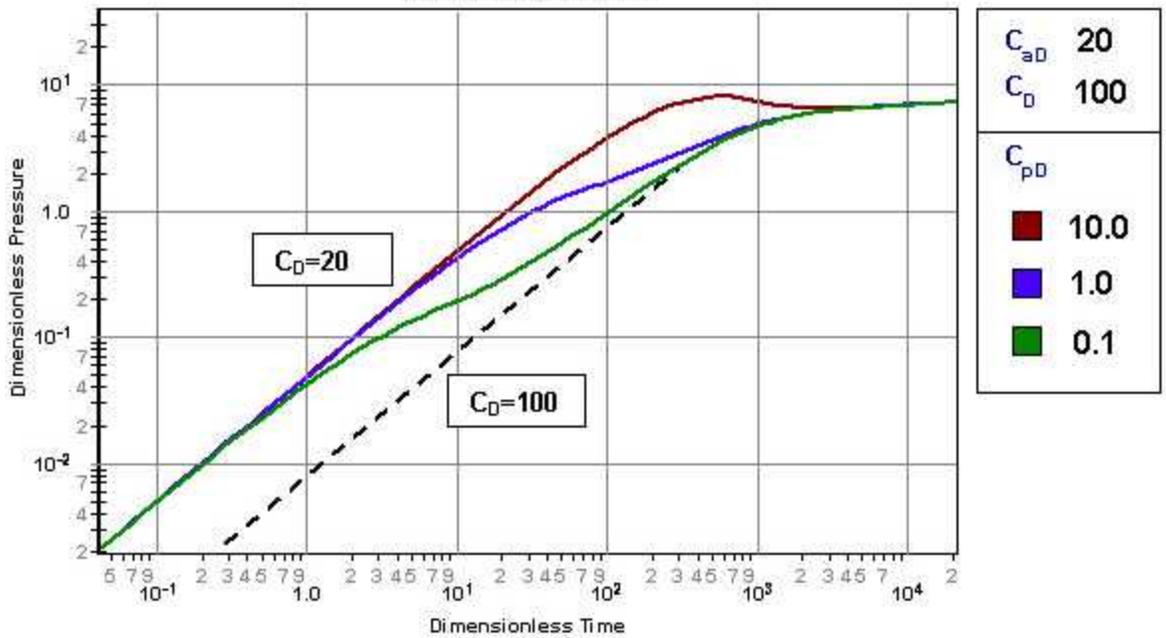
$$P_{pD} = C_{pD} \operatorname{erf} \left(\frac{t_D}{\alpha_D} \right)$$

However, it has been found in practice that the models of Fair and Hegeman et al. are not substantially different.

The following plots illustrate the effects of the three dimensionless storage parameters on the dimensionless typecurves.

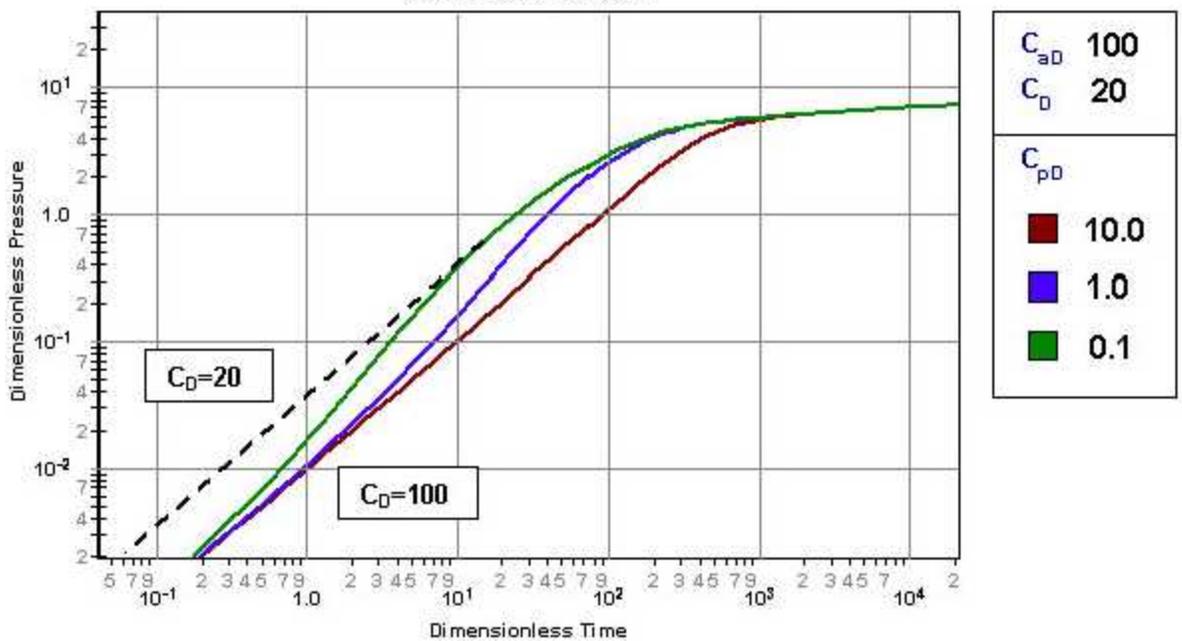
Case I : $C_{aD} < C_D$

Dimensionless Typecurve



Case II : $C_{aD} > C_D$

Dimensionless Typecurve



Dimensionless wellbore storage constant (C_D)

The wellbore storage constant in dimensionless form is defined as:

$$C_D = \frac{5.615 \cdot C}{2\pi\phi c_i r_w^2 h} = \frac{0.894 \cdot C}{\phi c_i r_w^2 h}$$

A large value of dimensionless wellbore storage is associated with a large wellbore volume (V_w). In practice, a range of values from 500 to 10000 has been observed. Occasionally, a value much greater than 10,000 is observed when actual test data are matched against a typecurve. In such cases, it is considered that some part of the formation (high permeability or fracture) is in communication with the wellbore, and is acting as an extension to it.

In a horizontal or slant well, the dimensionless wellbore storage constant is sometimes expressed in terms of the effective wellbore half-length ($L_e / 2$). In such a case, the value for wellbore radius (r_w) in the above equation is replaced by the effective wellbore half-length which makes the dimensionless wellbore storage constant a very small number.

Wellbore storage is normally assumed to be constant during a test and, in practice, this assumption is often reasonable. However, there are numerous situations where wellbore storage is not constant. This changing wellbore storage may be caused by a changing wellbore fluid compressibility, by phase redistribution, or by a change in the type of storage from a changing liquid level to a liquid filled wellbore. Changing wellbore storage is accounted for using a modified form of the dimensionless wellbore storage definition, which includes additional dimensionless parameters: apparent dimensionless storage (C_{aD}) and a storage pressure parameter (C_{pD}).

The wellbore storage constant and dimensionless wellbore storage constant are calculated from the early time data, by performing an afterflow or wellbore storage analysis.

Nomenclature

The table below outlines key nomenclature in Harmony Enterprise.

Variable	Description
a	Nominal (instantaneous) decline rate
a _{elf}	Decline rate at end of linear flow
a _f	Final nominal (instantaneous) decline rate
a _i	Initial nominal (instantaneous) decline rate
a _{lim}	Limiting nominal (instantaneous) decline rate

Variable	Description
A	Area
A_c	Cross-sectional area to flow
A_D	Areal extent of reservoir
A_o	Gas-oil pore size distribution index
A_{SRV}	Area of stimulated reservoir volume
A_w	Oil-water pore size distribution index
AD	Active directory
AOF	Absolute open flow potential
APE	Automatic parameter estimation
API	American Petroleum Institute number
API	Application programming interface
AWS	Amazon web services
b	Decline exponent
$b_{a,pss}$	Pseudo-steady state constant in the flow equation using material balance pseudo-time (gas)
b_{Dpss}	Dimensionless pseudo-steady state constant
b_{pss}	Pseudo-steady state constant in the flow equation using material balance time (oil)
B	Formation volume factor
B_g	Formation volume factor for gas
B_{gd}	Dry gas formation volume factor, ft ³ /scf, m ³ /m ³
B_{gi}	Formation volume factor for gas at initial reservoir pressure and temperature
B_{ginj}	Formation volume factor for injected gas
B_o	Formation volume factor for oil, bbl/stb, m ³ /m ³
B_{ob}	Formation volume factor for oil at bubble point

Variable	Description
B_{oi}	Formation volume factor for oil at initial reservoir pressure and temperature
B_w	Formation volume factor for water
B_{wi}	Formation volume factor for water at initial reservoir pressure and temperature
B_{winj}	Formation volume factor for injected water
BOE	Barrel of oil equivalent
c	Compressibility
c_d	Relative change in pore volume due to desorption of gas
c_e	Effective compressibility. For oil systems, includes oil, water, and formation compressibilities. For gas systems, includes gas, water, and formation compressibilities.
c_{ep}	Relative change in pore volume due to formation and residual fluid expansion
c_f	Formation / pore compressibility
$c_{f,max}$	Formation compressibility at zero net overburden pressure
c_{fi}	Initial formation compressibility
c_g	Gas compressibility
\bar{c}_g	Average gas compressibility
c_i	Initial compressibility
c_{ma}	Matrix compressibility
c_o	Oil compressibility
c_t	Total compressibility
c_{te}	Total compressibility at average reservoir pressure including net gas compressibility due to water influx

Variable	Description
c_{ti}	Total initial compressibility
c_T	Isothermal compressibility
$c_{T,w}$	Isothermal compressibility of water
$c_{T,wf}$	Isothermal compressibility of gas-free water
$c_{T,wg}$	Isothermal compressibility of gas-saturated water
c_{ti}	Total system compressibility at original reservoir pressure
c_w	Water compressibility
c_{wip}	Relative change in pore volume due to water influx and production
C	Transfer coefficient related to flow capacity of the formation
CCA	Custom calculated attributes
CD	Storage coefficient
CDF	Cumulative distribution function
CDI	Formation and connate water compressibility drive index
CF	Casing flange (reference point for depth measurements)
CGR	Condensate gas ratio, bbl/MMscf, m ³ /103m ³
C_a	Ash content (<u>Langmuir isotherm</u>)
CA	Reservoir shape factor
C_aD	Dimensionless apparent wellbore storage
CAh	Shape factor for horizontal wells
CD	Dimensionless wellbore storage
C_g	Gas content
$C_{g,abdn/CO_2}$	Gas content at abandonment pressure or CO ₂ concentration
C_{gi}	Initial gas content
C_G	Input gas volume fraction

Variable	Description
C_L	Liquid input volume fraction
C_m	Matrix swelling coefficient
C_o	Gas-oil entry capillary pressure
C_p	Mechanical compliance coefficient
C_{pD}	Dimensionless storage pressure parameter
C_w	Oil-water entry capillary pressure. Moisture content. (<u>Langmuir isotherm</u>)
Cal rate	Calendar rate — does not account for time on production.
d	Effective decline rate
d_i	Initial effective decline rate
d_{lim}	limiting effective decline rate
D	Turbulence factor
DD %	Drawdown percentage
DDI	Depletion drive index
DLS	Dominion land survey
DSN	Data source name
E	Young's modulus of elasticity
EC2	Elastic compute cloud by Amazon is a web service that can be used to create virtual machines running various operating systems on the cloud
EMS	Entitlement Management System (EMS)
ENERDEQ®	IHS's Energy Information Access & Integration Platform is an information access and integration platform that directly connects you to global energy data
Entity	A well or scenario. Groups can include various entities (that is, wells and scenarios).
ESP	Electrical submersible pump

Variable	Description
EOT	End of tubing
EUR	Expected ultimate recovery
E_{avg}	Average error
E_{fw}	Formation expansion factor
E_g	Gas expansion factor
E_{gi}	Gas expansion factor at initial conditions
E_L	In-situ liquid volume fraction (liquid holdup)
E_{L0}	Horizontal liquid holdup
$E_{L\theta}$	Inclined liquid holdup
E_o	Oil expansion factor
E_t	Total expansion factor
f	Decimal fraction
f_c	Compressibility modifier
F	Reservoir voidage from production
FDBC	Fekete database connection tool
FMB	Flowing material balance
Forecast	Used to predict future production
FP	Flowing pressure
FSD	Forecast start date
F_{CD}	Dimensionless fracture conductivity
g_g	Geothermal gradient
G	Original gas-in-place
G	Separator gas specific gravity (for fluid properties)
GHV	Gross heating value

Variable	Description
GMB	Gas material balance
GOR	Producing gas-oil ratio
GWR	Gas water ratio
G_f	Free gas-in-place
G_{inj}	Cumulative gas injected
G_p	Cumulative gas production
G_{pa}	Additional gas production
$G_{p,n}$	Ultimate recoverable gas
G_{pn}	Cumulative gas production at time 'n'
G_r	Remaining gas
G_T	Cumulative transferred gas volume in a connected reservoir
h	Net pay
h_p	Perforated interval
HCPV	Hydrocarbon pore volume
History matching	History matching is the process of evaluating your model against known production data (rate and pressure vs. time). For example, in an Analytical model, the inputs are measured sandface pressures and rates, along with a set of fixed parameters like permeability, initial reservoir pressure, saturations, etc. Since a model is just a complex equation that relates pressure to rate, then the measured rates can be applied to a given model in order to synthesize a set of sandface pressures (or vice versa). The history-matching process then consists of changing the model parameters until the synthesized data overlaps the measured data to a reasonable degree.
I	Incline rate
IAM	Identity and access management (for Azure)
ID	Inner diameter

Variable	Description
IHDC	Information hub direct connect — the Canadian-specific portion of IHS web services
IPR	Inflow performance relationship
IWIP	Initial water-in-place
j	Time interval / timestep
J	Transfer coefficient
J _{sat}	Productivity index. For more information, see Fetkovich-based fit .
k	Permeability
k _{abs}	Absolute permeability
k _{aq}	Aquifer permeability
k _e	Effective roughness of pipe
k _f	Fracture permeability
k _g	Effective permeability of gas
k _h	Horizontal permeability
k _i	Initial permeability
k _{matrix}	Matrix (outer zone) permeability
k _o	Effective permeability of oil
k _r	Pressure-dependent permeability ratio: $k_r = k / k_i$
k _{res}	Reservoir permeability
k _{rg}	Gas-relative permeability
k _{rgc}	Gas-relative permeability at residual oil saturation
k _{rgcw}	Gas-relative permeability at connate water saturation
k _{rgro}	Gas-relative permeability at residual oil saturation
k _{ro}	Oil-relative permeability
k _{rocw}	Oil-relative permeability at connate water saturation

Variable	Description
k_{rog}	Oil-relative permeability with respect to gas
k_{rogc}	Oil-relative permeability at critical gas saturation
k_{row}	Oil-relative permeability with respect to water
k_{rw}	Water-relative permeability
k_{rwgc}	Water-relative permeability at critical gas saturation
k_{rwro}	Water-relative permeability at residual oil saturation
k_{srv}	<u>SRV</u> (inner zone) permeability
k_v	Vertical permeability
k_w	Effective permeability of water
k_x	Permeability in the x-direction
k_y	Permeability in the y-direction
k_z	Permeability in the z-direction
KB	Kelly bushing (reference point for depth measurements)
L	Horizontal wellbore length
L_D	Dimensionless horizontal wellbore length
L_e	Effective horizontal wellbore length
LRG	Liquid rich gas
m	Slope from the flow equation using material balance time (oil)
m_a	Slope from the flow equation using material balance pseudo-time (gas)
M	Mobility ratio (analytical models) (water-drive typecurves)
MD	Measured depth (CF or KB)
MPP	Mid-point of perforations
M_{aq}	Aquifer mobility

Variable	Description
M_o	Molecular weight of stock tank liquid
M_{res}	Reservoir mobility
n	Moles of gas (<u>ideal gas law equation</u>)
n_f	Number of fractures
n_g	Gas exponent
n_{og}	Oil-gas system exponent
n_{ow}	Oil-water system exponent
n_w	Water exponent
N	Original oil-in-place
NAD 27	North American Datum, created in 1927
NAD 83	North American Datum, modified in 1983
NGL	Natural gas liquids
NTS	National topographic (map numbering) system
N_p	Cumulative oil production
$N_{p,n}$	Ultimate recoverable oil
N_{VL}	Liquid velocity number
ODBC	Open database connectivity
OCIP	Original condensate-in-place, Mstb, 103m ³
OCIP _{SRV}	Original condensate-in-place in a stimulated region, Mstb, 103m ³
OD	Outer diameter
ODBC	Open database compliant
OFIP	Original fluid-in-place
OGIP	Original gas-in-place, MMscf, 106m ³
OGIP _A	Original adsorbed gas-in-place, MMscf, 106m ³
OGIPF	Original free gas-in-place, MMscf, 106m ³

Variable	Description
OGIP _{SRV}	Original gas-in-place in a stimulated region, MMscf, 106m ³
OMB	Oil material balance
OOIP	Original oil-in-place, Mstb, 103m ³
OOIP _{SRV}	Original oil-in-place in a stimulated region, Mstb, 103m ³
OWIP	Original water-in-place, Mstb, 103m ³
OWIP _{SRV}	Original water-in-place in a stimulated region, Mstb, 103m ³
Op Rate	Operated rate — accounts for time on production.
p	Pressure
\bar{p}	Average reservoir pressure
p _{ab}	Abandonment pressure
p _{air}	Air pressure
p _{aq}	Aquifer pressure
p _{aqi}	Initial aquifer pressure
p _{bp}	Bubble point pressure, psi(a), kPa(a)
p _c	Critical pressure
(p _{ce}) _{go}	Gas-oil pore entry capillary pressure, psi(a), kPa(a)
(p _{ce}) _{ow}	Oil-water pore entry capillary pressure, psi(a), kPa(a)
p _{cgo}	Gas-oil system capillary pressure, psi(a), kPa(a)
p _{cow}	Oil-water system capillary pressure, psi(a), kPa(a)
p _d	Desorption pressure
p _{dew}	Dew point pressure, psi(a), kPa(a)
p _D	Dimensionless pressure
p _{Di}	Dimensionless pressure integral
p _{Did}	Dimensionless pressure integral derivative
p _e	Bulk overburden pressure

Variable	Description
P_{flow}	Specified flowing pressure
P_{grd}	Overburden pressure gradient
P_i	Initial reservoir pressure
P_j	Pressure at time "j"
P_L	Langmuir pressure
P_{max}	Maximum pressure
P_{min}	Minimum pressure
P_n	Net overburden pressure
P_{ni}	Initial net overburden pressure
P_o	Oil pressure
P_p	Pseudo-pressure
\bar{P}_p	Average pseudo-pressure
P_{pab}	Abandonment pseudo-pressure
\bar{P}_{pab}	Average abandonment pseudo-pressure
P_{pi}	Initial pseudo-pressure
P_{pwf}	Wellbore flowing pseudo-pressure
P_r	Reduced pressure
\bar{P}_R	Current reservoir pressure
P_{sp}	Separator pressure
P_{sc}	Pressure at standard conditions (14.65 psia, 101.0 kPa(a))
P_w	Water pressure
P_{wf}	Sandface flowing pressure
P_{wff}	Sandface forecast pressure
P_{wh}	Wellhead flowing pressure

Variable	Description
p_{ϵ}	Reservoir pressure at 50% matrix strain
P10	For each time interval, the P10 point is determined as the value for which 10% of the data points are higher. The production volume for each period is based on the calculated rate, and the cumulative production track is calculated by summing the calculated volumes. The P10 curve can be considered a highly optimistic prediction.
P50	For each time interval, the P50 point is determined as the value for which 50% of the data points are higher. The production volume for each period is based on the calculated rate, and the cumulative production track is calculated by summing the calculated volumes.
P90	For each time interval, the P90 point is determined as the value for which 90% of the data points are higher. The production volume for each period is based on the calculated rate, and the cumulative production track is calculated by summing the calculated volumes. A line is drawn through each P90 point to obtain the curve. The P90 curve is often considered as a conservative estimate of reserves.
PI	Productivity index
PVT	Pressure volume temperature
P_c	Capillary pressure SPE recommends P_c (P being the secondary symbol for pressure) to denote capillary pressure, whereas p_c is used to denote critical pressure.
P_{OP}	Operating pressure
P_{RES}	Reservoir pressure
P_{SF}	Sandface pressure
q	Rate
\bar{q}	Average rate
q_{ab}	Abandonment rate
q_{CRIT}	Critical flow rate
q_D	Dimensionless rate
q_{Dd}	Dimensionless decline rate

Variable	Description
q_{Dde}	Dimensionless decline rate accounting for total pool production
$Q_{Dd, \text{integral}}$	Dimensionless rate integral
q_{elf}	Rate at end of linear flow
q_f	Final rate (abandonment rate) $q_f = (\text{number of wells}) * (q_{\text{Gas}} / 6 + q_{\text{Oil}})$;
q_g	Instantaneous gas rate
$(q_g)_f$	For <u>FMB</u> , <u>URM</u> , and <u>Typecurve</u> : The final abandonment rate for gas
q_{ginj}	Injected gas rate
q_i	Initial rate
q_{integral}	Rate integral
q_j	Rate at time "j"
Q_{MAX}	Maximum oil rate
q_o	Instantaneous oil rate
$(q_o)_f$	For <u>FMB</u> , <u>URM</u> , and <u>Typecurve</u> : The final abandonment rate for oil
Q_{OIL}	Oil rate
Q_{OR}	Operating rate
q_s	Gas flow rate from separator
q_{tot}	Pool total production rate
q_w	Instantaneous water rate
q_{we}	Rate of water influx
q_{winj}	Rate of water injection
Q	Cumulative production
Q_D	Dimensionless cumulative production

Variable	Description
Q_{DA}	Area-based dimensionless cumulative production
Q_{Dd}	Dimensionless cumulative decline production
Q_f	Final cumulative production
$Q_{g,dry}$	Cumulative surface gas production
$Q_{g,wet}$	Cumulative well stream gas produced at the sandface
Q_i	Initial cumulative production
Q_m	Modified cumulative production
Q_n	Normalized cumulative production
Q_{tot}	Pool cumulative production
r	Radius
r_{aq}	Aquifer exterior radius
r_e	Reservoir effective radius
r_{eD}	Dimensionless effective radius
r_o	Reservoir outer boundary radius (Water-drive Typecurves and Models) Distance to observation well from active well, for cylindrical reservoirs
r_w	Wellbore radius
r_{wa}	Apparent wellbore radius
r_{wD}	Dimensionless wellbore radius
r_{we}	Effective wellbore radius
R	Ideal gas law constant
RC	Rate vs cumulative production
RDP	Remote desktop protocol
RDS	Relational Database Service created by Amazon

Variable	Description
RF	Recovery factor
RR	Remaining recoverable
RT	Rate vs time
R _p	Solution gas-oil ratio based on cumulative oil and gas production
R _s	Solution gas-oil ratio, scf/bbl, m3/m3
R _{sb}	Solution gas-oil ratio at bubble point
R _{si}	Initial solution gas-oil ratio
R _{sr}	Reduced solution gas-oil ratio
R _{sw}	Gas solubility in water
R _v	Vaporized oil ratio, bbl/MMscf, m3/103m3
s	Skin
s _d	Near-wellbore skin damage
s _{dφ}	Interporosity skin
s _f	Fracture face skin
S	Salinity of water
Sandface C	Sandface deliverability coefficient
Sandface/Wellhead n	Turbulence factor
SDI	Segregation (gas cap) Drive Index
SI	International system of units. For more information, see http://-dictionary.reference.com/browse/si+units?s=t
SL	Surface losses
SPE	Society of petroleum engineers
SQL	Structured query language
SRV	Stimulated reservoir volume
S _{ads}	Adsorbed gas saturation

Variable	Description
S_g	Gas saturation
S_{gc}	Critical gas saturation
S_{gi}	Initial gas saturation
S_{gn}	Normalized gas saturation
S_{iw}	Irreducible water saturation (Relative Permeability Correlations)
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{on}	Normalized oil saturation
S_{or}	Residual oil saturation
S_{org}	Residual oil saturation to gas
S_{orw}	Residual oil saturation to water
S_w	Water saturation
S_{wc}	Critical water saturation (<u>capillary pressure</u>)
S_{wc}	Connate water saturation (<u>relative permeability</u>)
S_{wi}	Initial water saturation
S_{wirr}	Irreducible water saturation (<u>capillary correlations</u>)
S_{wn}	Normalized water saturation
\bar{S}_w	Average water saturation
t	Time
t_a	Pseudo-time
t_c	Material balance time
t_{ca}	Material balance pseudo-time
t_{cae}	Total material balance pseudo-time for gas
t_{ce}	Total material balance pseudo-time for oil

Variable	Description
t_{co}	Length of the first time period in material balance time
t_D	Dimensionless time
t_{DA}	Area-based dimensionless time
t_{Dd}	Dimensionless decline time
t_{Dde}	Dimensionless decline time accounting for total pool production
t_{Dxf}	Dimensionless time based on fracture half-length (x_f)
t_{Dye}	Dimensionless time based on reservoir width (Y_e)
t_{elf}	Time at end of linear flow
t_f	Time at start of forecast date
t_{flow}	Specified flow time
t_j	Time at the "jth" time period / timestep
t_{lim}	Limiting time
$t_{shut-in}$	Specified shut-in time
t_{stab}	Time to stabilization
T	Temperature
TVD	True vertical depth (CF or KB)
TPC	Tubing performance curve
T_c	Critical temperature
T_f	Formation temperature
T_i	Initial temperature
T_{pp}	Pour point temperature
T_r	Reduced temperature
T_{sp}	Separator temperature
T_{sc}	Temperature at standard conditions (60oF/15oC)

Variable	Description
T_{sp}	Separator temperature
<u>URM</u>	Unconventional reservoir module
v_g	Gas velocity
v_L	In-situ liquid velocity
v_m	Mixture velocity
v_{sg}	Superficial gas velocity
v_{sl}	Superficial liquid velocity
V	Volume
VM	Virtual machine
VR	Voidage replacement
VRR	Voidage replacement ratio
V_{ACT}	Actual velocity
V_{aq}	Aquifer volume
V_{CRIT}	Critical velocity
V_{ERO}	Erosional velocity
V_{HCP}	Hydrocarbon pore volume
V_i	Initial volume
V_L	Langmuir volume
V_{Li}	Initial Langmuir volume
V_p	Pore volume
V_R	Volatile oil ratio Rock volume
V_{sc}	Volume at standard conditions
V_T	Total volume

Variable	Description
V_w	Wellbore volume
w_f	Fracture width
WBS	Well-based security
WDI	Water drive index
WGR	Water gas ratio
WGS 84	World Geodetic System, modified in 1984
WOR	Water-oil ratio
W_e	Water encroachment from aquifer
W_{ei}	Initial water encroachment from aquifer
W_{inj}	Cumulative water injection
W_p	Cumulative water production
x_e	Reservoir length
x_{eD}	Dimensionless reservoir length
x_f	Fracture half-length
x_i	Half <u>SRV</u> width, or the distance from the fracture to the permeability boundary
x_w	Active well location in the x-direction
y	Distance of investigation at time t
y_e	Reservoir width
y_w	Active well location in the y-direction
y_e/y_w	Ratio of reservoir width to well location in the y-direction
Z	Gas compressibility factor
Z^{**}	Modified gas compressibility factor
\bar{Z}	Average gas compressibility factor
Z_{ab}	Compressibility factor at reservoir abandonment pressure

Variable	Description
Z_i	Compressibility factor at initial pressure and temperature
Z_i^{**}	Modified compressibility factor at initial pressure and temperature
z_o	Location of observation well from top of zone (z-direction) for rectangular reservoirs
Z_{sc}	Compressibility factor at standard conditions
z_w	Well location in the z-direction (only applicable to horizontal wells)
α	Biot's coefficient (<u>Geomechanical Reservoir Models - Dobrynin Correlation</u>) Separation factor / selectivity ratio (<u>Langmuir Isotherm</u>)
β	Square root of the anisotropic ratio k_h/k_v
β_D	Ratio of total pool production to individual well production
γ	Permeability modulus (<u>Geomechanical Reservoir Models - Yilmaz & Nur Pressure-Dependent Permeability Correlation</u>) Dimensionless correlation factor (<u>Geomechanical Reservoir Models - Dobrynin Pressure-Dependent Permeability Correlation</u>) Euler's constant = 0.57721
γ_{API}	Specific gravity of liquid hydrocarbons / condensate in oAPI
γ_g	Specific gravity of gas
$\gamma_{g(psp)}$	Specific gravity of gas at separator pressure conditions
γ_o	Specific gravity of liquid hydrocarbons / condensate
γ_t	Recombined gas gravity
γ_w	Specific gravity of water
Δk	Change in permeability
Δp_f	Change in pressure due to friction
Δp_{HH}	Change in pressure due to hydrostatic head
ΔQ	The difference between $Q_{PRODUCTION} - Q_{FORECAST}$ (applies to the

Variable	Description
	<u>Monitor tab</u>)
Δt	Forecast duration
ΔV_d	Change in reservoir volume due to desorption of gas
ΔV_{ep}	Change in reservoir volume due to formation and residual fluid expansion
ΔV_p	Reduction in hydrocarbon pore volume
ΔV_w	Expansion of initial water volume
ΔV_{wip}	Change in reservoir volume due to water influx and production
ΔX_o	Location of observation well from active well in the x-direction, for rectangular reservoirs
ΔY_o	Location of observation well from active well in the y-direction, for rectangular reservoirs
ΔZ	Change in elevation
ϵ	Tensile strain
ϵ_{exp}	Net strain between overburden stress effect and matrix shrinkage as measured experimentally
ϵ_L	Langmuir strain
θ	Angle of inclination
θ_r	$[(T + 459.67) / 459.67] =$ relative temperature
λ	Interporosity flow coefficient Pore size distribution index (<u>Capillary Correlations - Brooks / Corey</u>)
λ_{go}	Gas-oil pore size distribution index
λ_{ow}	Oil-water pore size distribution index
μ	Viscosity of primary fluid (gas / oil / water)
$\bar{\mu}$	Average viscosity

Variable	Description
μ_{aq}	Aquifer viscosity
μ_g	Gas viscosity, cP, mPa.s
$\bar{\mu}_g$	Viscosity of gas at average pressure
μ_i	Viscosity at initial reservoir pressure
μ_L	Liquid viscosity
μ_m	Mixture viscosity
μ_{NS}	No-slip viscosity
μ_o	Oil viscosity, cP, mPa.s
μ_{ob}	Oil viscosity at bubble point
μ_{od}	Viscosity of dead oil
μ_{os}	Viscosity of saturated oil
μ_{res}	Reservoir viscosity
μ_w	Water viscosity, cP, mPa.s
ν	Poisson's ratio
ξ	Reduced inverse viscosity
ρ	Density
ρ_a	Apparent density of surface gas
ρ_{air}	Air density
ρ_{ads}	Density of the adsorbed gas phase
ρ_b	Bulk density
ρ_G	Gas density
ρ_L	Liquid density
ρ_m	Mixture density
ρ_{mol}	Molar density

Variable	Description
ρ_{NS}	No-slip density
ρ_o	Oil density
ρ_{ob}	Oil density at bubble point
ρ_{oR}	Oil density at reservoir conditions
ρ_{po}	Pseudo-liquid density at standard conditions
ρ_{st}	Stock tank oil density
ρ_w	Water density
σ	Interfacial tension (<u>capillary pressure</u>)
σ_i	Effective horizontal stress at initial reservoir pressure
ϕ	Porosity
ϕ_i	Initial porosity
ϕ_t	Total porosity
ψ	Pseudo-pressure
$\bar{\psi}$	Pseudo-pressure at average pressure
ψ_i	Pseudo-pressure at initial reservoir pressure
ψ_{wf}	Pseudo-pressure at sandface flowing pressure
ω	Storativity ratio

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Index

A

- accounting for
 - adsorbed GIP 180
 - changing oil properties 181
 - fluid changes during reservoir depletion 1083
- activating licenses 62
- active directory 26
- adding
 - analysis 411
 - anchor point 143
 - bubble map 525
 - bubble map layer 514
 - category 418, 484
 - dataset 418, 484
 - distribution cards 287
 - flag 514
 - general annotation 514
 - image layer 514
 - reference date 596
 - shapefile layer 514
- adjusting gridding 285
- advanced
 - analytical options 140
 - forecast 119
 - numerical model options 280
- analysis manager 410

- analysis method theory 631
 - Agarwal-Gardner 764
 - analytical 632
 - Blasingame 776
 - compound linear 799
 - decline 637
 - Duong 683
 - Fetkovich 812
 - FMB 652
 - hybrid 720
 - material balance 688
 - multiphase FMB 670
 - NPI 838
 - probabilistic decline 756
 - stretched exponential decline 757
 - surveillance 757
 - traditional decline 637
 - transient 844
 - typecurve 764
 - typewell 859
 - unconventional theory 860
 - volumetrics 882
 - Wattenbarger 852
- analysis tab 414
- analysis types 118
 - advanced forecast 119
 - analytical 127
 - custom forecast 148

decline 150
Duong 160
flowing gradient 164
FMB 169
forecast consolidation 184
material balance 199
multi-segment decline 207
multi-well 211
numerical 268
oil cut 312
probabilistic 286
probabilistic decline 326
ratio forecast 327
ratio trend 328
stretched exponential decline 335
surveillance 339
typecurve 345
URM 367
volumetrics 382
WOR 383
WOR / oil cut forecast 386

analytical analysis 127

- adsorption 141
- boundary type 142
- changing skin 141
- changing storage 142
- dual porosity 143
- geomechanical 142

- PVT pressure 143
- Analytics Explorer 415
- analyzing
 - entities 95
 - wells 94
- anchoring 143
- annular diameters 890
- APE
 - theory 984
 - using (analytical) 146
- applying a workflow 109
- artificial lift 976
 - gas lift 979
 - pumping 976
- assign mapping
 - dialog box 439
 - errors 441
 - min requirements 441
- attributes 415
- auto update 535
- autocalc sandface pressure 535
- automatic parameter estimation theory 984
- average reservoir pressure calculations 891

B

- b value 1161
 - changing 432
- batch export 98
- Blasingame (log-log) 1034

bubble maps 525
bulk editor 436
bulk export 98
bulk modify declines 607

C

calculations 889
 average reservoir pressure 891
 flow rate 895
 liquid lift 899
 methods 889
 pressure loss 920
 pressure loss in multilayer wells 958
capillary correlations 892
capillary pressure 986
CCA 1163
CF 1163
CGR 1163
changing
 abandonment rate 434
 b value 432
 b value & final cumulative prod 433
 final cumulative prod & decline rate 433
 forecast start date 431
 historical match 430
 initial cumulative prod & final cumulative prod 432
 initial rate 430
 slope of decline curve 429

- choke
 - sizing 988
- clipboard 389
- cloud 37
- column sorting 416
- command line 536
- commuter 67
- compare plots 582
- comparison plot 602
- components 410
- connecting
 - to a remote database 77
 - to your data source 72
 - using dsn file 77
- consolidation 184
- constant-pressure boundaries 142
- contact us 1195
- continuous time track 993
- correlations
 - capillary 892
 - gas 896
 - geomechanical 899
 - oil 900
 - relative permeability 969
 - water 974
- creating
 - bubble map 525
 - workflow 108

custom groups 505

D

data diagnostics

 flowchart 1015

 theory 994

database connection 438

 mapping 439

database connection wizard 83

datum depth 226

DB deployment

 enable RBS 29

 troubleshooting 35

DB management 28

 add groups or users 29

 configuring 31

 create DB 28

 defrag 33

 release orphaned wells 34

 unlock wells 34

decline analysis

 Arps' 150

 Duong 160

 multi-segment 207

 probabilistic 326

 stretched exponential 335

decline worksheet 619

deleting

 reference date 596

diagnostic line 586

Diagnostics tab

overview 446

dialog box

analyses selection 577

assign mapping 439

create custom attribute 426

create custom dataset 491

create workflow 111

data reduction 550

equation editor 426

export type 576

facility annotation editor 524

filter a column 442

IHS Markit online activation 70

import data 541

import options 444

license info 67

licensing 65

licensing settings 68

link incoming wells to existing wells 546

options 558

query wells 592

reference dates 595

select analyses to import 444

select wells to import 442

set up connection settings 438

set up filters 442

- well-analysis pairing conflicts 577
- dimensionless wellbore storage 1160
- DLS 1164
- DMA 49
- docking
 - context menu 397
 - reset to original settings 396
- drainage area 531
- drawdown % 1031
- dual porosity 1040

E

- economics 449
- editors 455
 - multilayer allocation 502
 - production 483
 - properties 455
 - static pressure 499
 - wellbore 472
- effective decline rate 1131
- ENERDEQ 1164
 - queries 87
- entities
 - on the GIS map 513
 - selecting 398
 - work status 510
- Entity 1164
- entity viewer
 - custom 505

- hierarchy 508
- equivalence
 - constant rate/pressure 1046
- EUR 1165
- event scheduler 242
- example files 8
- exponential decline equation 641
- exporting data 98
 - .hldb file 105
 - Analytics Explorer 107
 - decline parameters 101
 - forecasts 100
 - Mosaic 102
 - Piper 103
 - production data 98
 - WellTest 104

F

- Fetkovich time reinitialization 361
- FieldDIRECT 84
- flags 532
- floating 397
- floating, tabbed window 403
- flow rate calculations 895
- flowing material balance
 - analysis 169
 - theory 652
- FMB
 - accounting for changing oil properties 181

analysis 169

analyzing reservoirs with aquifer support 175

data filter dialog box 182

including pressure-dependent permeability & formation compressibility 179

pressure (Cartesian) 1039

rate (Cartesian) 1037

theory 652

 model 679

 multiphase 670

forecast

 consolidation 184

 custom 148

 ratio 327

 WOR / oil cut 386

 worksheet 629

forecasting

 gas condensate systems 134

 using wellhead pressure (analytical) 136

 using wellhead pressure (numerical) 279

fracture properties 1047

FST 151

G

gas AOF / TPC

 theory 684

gas correlations 896

gas IPR / TPC 185

 artificial lift outflow 196

 custom table inflow 193

- Forcheimer inflow 193
- simplified C,n 191
- gas lift
 - conventional 980
 - poor boy 980
- general concepts 975
- generating
 - Agarwal-Gardner gas analysis 657
- geomechanical correlations 899
- geomechanical reservoir models 1049
- get wells into Harmony Enterprise 78
- GHV 1165
- GIS 512
 - layers 521
 - map 519
 - tab, flag properties 533
 - tab, legend 516
 - theory 1054
- glossary 1160
- GMB 199
 - advanced 204
 - plots and parameters 203
- GOR 1166
- grids 614

H

- Hall plot 339
- harmonic decline equation 644
- Harmony Enterprise example files 79

history matching 1166

 using E avg 984

hldb

 defrag 394

 import from 90

hyperbolic decline equation 642

I

icons

 checkmark 507, 511

 entity viewer 510

 exclamation mark 507, 511

 GIS map 516

 question mark 507, 511

IHDC 86

importing

 from Aries 84

 from Enerdeq 86

 from multi-user Harmony 90

 from Piper forecasts 88

 from PowerTools 89

 from WellTest 90

 functionality 534

 Harmony logic 1153

 import data dialog box 541

 import options dialog box 444

 well data from a database 83

 well data from a file or group 79

injection 144

interpolation theory 1065

IWIP 1167

K

KB 1168

L

Langmuir isotherm 1066

latitude / longitude

theory 1060

layers

GIS 521

well 617

LGR 262

licensing 62

Forecast license 118

Optimize license 118

Reservoir license 118

linking

analyses 113

imported wells 546

order of precedence 112

liquid life calculations 899

liquid loading

in the wellbore 997

theory 687

local DB 391

locking 415

log gas rate 1027

logging directory 27

M

manipulating

 multi-segment decline 435

 multiple segments 434

map

 GIS legend 516

 imported wells 546

material balance

 analysis 199

 gas 199

 oil 206

 theory 688, 1068

menus 391

merging

 custom-input attributes 420

modifying

 geomechanical models (pseudo-press) 1086

 geomechanical models (pseudo-time) 1090

 linked wells 547

 workflow 109

modules 410

Monitor tab 553

 liquid loading 556

 production vs. forecast 553

MPP 1168

multi-well analysis 211

 conventional 211

 unconventional 245

multiwell

 conventional 211

 unconventional 245

N

navigation 389

network seat 66

nodal analysis

 advanced forecast 119

 flowing gradient 164

nomenclature 1160

NPI (log-log) 1036

numerical analysis 268

 adjusting gridding 285

 adsorption 281

 changing skin 283

 geomechanical 281

 refracturing 281

 sparse data 283

 URM 299

numerical URM theory 732

O

OFIP 1169

OGIP 1169

oil correlations 900

oil IPR / TPC 314

 artificial lift outflow 323

 custom table inflow 320

 Vogel inflow 318

oil IPR theory 715
oil PVT change 1083
OOIP 1170
optimize 118
options 558
orange text 402
outlier removal 998
overview 10

P

panes 394
PDP 1097
percentile forecasts 295
permeability, relative 1090
Piper export 576
 logs 578
plot
 components 580
plot selection pane 589
plots 579
 legend 580
 locks 580
 types 582
point selection
 best fitting 407
PPDP 1097
pressure loss calculations
 examples, annulus=flow path 967
 examples, casing flow only 959

- examples, tubing=flow path 963
- preview well data 92
- private groups 506
- probabilistic
 - analysis 286
 - general concepts 1085
 - percentile calculations 296
 - speeding up the analysis 298
 - theory 743
- production editor 483
 - create custom datasets 491
 - equation editor 492
 - pressure calculations 495
- project filters 589
- promoting scenarios 512
- properties
 - GIS map 513
 - injected gas 982
 - of reservoir fluids 1100
 - of reservoirs 1117
 - of shale 1124
- pseudo-pressure 1085
- pseudo-time 1087
- query wells 592
- rate & pressure vs. time 1021

Q

R

- ratio analysis 118
 - oil cut 312
 - WOR 383
- ratio trend 328
- recombination 968
- red text 402
- reducing
 - hldb file size 394
- reference dates 595
- reference materials 631
- references 1183
- refracturing 281
- relative permeability 1090
 - 2-phase correlations 970
 - 3-phase correlations 973
 - correlations 969
- release notes 12
- reporting 604
- repositioning
 - tabs 403
- reserves evaluation 1094
 - classifications 1096
- reservoir
 - flow 1098
 - properties 1117
- reservoir fluids
 - properties 1100
 - types 1112

results tab 597

RF 1175

role-based security 610

RR 1175

S

saturated filter 379

scenarios 613

scheduled update 535

scheduling

- auto refresh results 538

- well updates 535

scrubber line 125

SE 10

shale properties 1124

shapefiles 523

shared groups 507

sharing, custom group 506

skin

- correcting effects 356

- on fracture face 1128

- time dependent 1134

sparse data 283

spatial explorer 614

- editable polygon layers 242

SRV 1175

status window 401

surveillance 339

symbol descriptions 516

T

- tables 614
- tabs 403
- task scheduler 535
- TDS 1111
- templates
 - applying to analyses 448
 - auto 447
 - deleting 449
 - renaming 449
- terminal decline calculations 1131
- test design 138
- time-dependent skin 1134
- time to stabilization 1136
- toolbar
 - analysis manager 411
- toolbars 403
- TPC 1177
- training 1196
- Turner rate 1025
- TVD 1177
- typecurve
 - analysis 345
 - Argarwal-Gardner 349
 - Blasingame 350
 - compound linear 352
 - data filter dialog box 365
 - Fetkovich 359

NPI 363
theory 764
Wattenbarger 364

U

unconventional reservoir 367
 data filter dialog box 380
 plots 372
 theory 860
unlinking analyses 116
updating
 database 33
 existing wells 548
user
 interface 410
 permissions in local folders 27

V

videos 1196
view definitions 439
viewing
 data field to be imported 439
 definitions (Excel file) 439
 results 96
volumetrics
 analysis 382
 theory 882
VR 1178
VRR 1178
VRR analysis 340

W

water correlations 974

water drive 1136

in FMB 1139

in GMB 1137

in OMB 1139

typecures 1139

WBS

configuring 31

prerequisites 31

WDI 1179

well-based security 31

well linking

criteria 441

logic 1151

well linking logic

Enerdeq special cases 1156

general 1151

Well Identifier special case 1154

well security 31

defintion 31

wellbore storage 1157

WGR & water rate 1028

wizard

DB connection 83

WOR 1179

forecasting theory 887

WOR analysis worksheet 629

workflows 107

 applying 109

 creating 108

 deleting 108

 modifying 109

 renaming 108

worksheets 617

 custom 630

 decline 619

 forecast 629

 material balance 628

 ratio 629

 typewell 620

 volumetrics 627