



CWM 2.2 WorkFlow

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Overview

The CWM is specifically designed for modelling commingled gas wells, though it is perfectly valid for the simpler single layer case. The results of the CWM in terms of layer and well rate and pressure evolution are broadly consistent with the discussion in the classic SPE paper 01329-G: A Study of the Behavior of Bounded Reservoirs Composed of Stratified Layers (Lefkovits et al , 1959-1960).

The CWM can be used for forward modelling of the expected behaviour of a commingled well. It also incorporates a methodology for estimating the GIIP associated with each individual layer, following the workflow outlined in SPE paper 158733: Estimating Zonal Gas-in-Place in a Commingled Well Using Results from Production Logs (Last, 2012)

The main features of the CWM are:

- Inflow performance calculations for each layer based on the input layer properties and a pseudo steady-state inflow equation. The use of pseudo steady-state inflow is more in line with the method of Tempelaar-Lietz, which is referenced in the Lefkovits paper, and introduces some inaccuracies at early time in each timestep. However, as Lefkovits pointed out in his paper, the differences between a more exact solution (transient inflow transitioning to PSS) and this simplified approach are usually small.
- The CWM is a time-stepping model, with the total-well gas flowrate at each timestep matched to the corresponding entry in an input Production History. At each timestep a material balance calculation is made for each layer, calculating the new layer GIIP and $p(\text{bar})$ based on the average layer rate during the timestep and the timestep duration. This GIIP & $p(\text{bar})$ are used as the starting point for the next timestep.
- Inflow is currently based on closed-tank material balance (i.e. P/Z). An aquifer model is under consideration but not yet incorporated.
- The inflow of each layer is based on layer properties, PSS inflow and the difference between the current $p(\text{bar})$ and the Pwf opposite that layer.
- Friction and hydrostatic pressure losses are calculated, in each timestep, both between each layer and back to the wellhead (i.e. FTP or flowing tubing head pressure)
- The total-well rate at each timestep is matched to the input in the Production History by setting Pwf at the bottom active layer, and marching upwards from that layer calculating

layer inflow, pressure losses to the next layer, Pwf and corresponding inflow from that layer, and so on. Pwf is adjusted automatically until the specified total-well rate is matched.

- A logical test is applied to ensure that layer pressure – $p(\text{bar})$ - cannot fall below the Pwf that prevails during a given timestep.
- The CWM can match either to FTP or to the total-well rate, as input in the Production History. It cannot match both at the same time!

The workflow for matching the MPLT/SIP (Selective Inflow Performance) results is discussed later in this guide.

New Project

File → New

Date → Units – select the desired units

General Data

Suggest to click “Defaults” which will populate the table with starting values.

Main entries to pay attention to:

- Geothermal gradient: for Gulf of Thailand this is likely 2.5 to 3 deg F /100 ft
- Bottom zone static temp. This refers to the lowest zone you plan to enter into the Layer Properties table
- Wellbore radius: this refers to the internal radius of the casing in the reservoir section (not to the open hole radius). For 2-7/8” monobore it’s 0.1017 ft/ 1.22 in. For 4-1/2” monobore it’s typically 1.996 in (depending on the weight).
- Default downflow properties: where flow is upwards, the software calculates the proportion of wellbore fluids from each interval and calculates the average mixture properties according to that combination. For the less common downflow case this calculation is more difficult and, for simplification of the solution, is not performed. Suggest to use rough averages for these “in case of downflow” defaults – it’s unlikely to be a significant issue.
- PDG mandrel: enter the MD of the PDG if there is one – or you can use this as a specific depth at which you want to be able to track/plot pressures.
- The rest: leave at default for now - the convergence solution in the case of 2-phase flow is still being optimized. Water rates and hold up calculations work OK with a zero slip assumption, not so well when slip velocity is > 0 .

You must click “Apply” in this and every other Data Entry tab after entering or changing data.

Well Trajectory

- MD and TVDRT (not TVDSS) to be entered here. Include 0,0 as the first point.

- Suggest to cull the typical well survey file (usually around 100 points) down to 30 or so points (keep every 3rd survey point). This reduces file size and the number of calculation steps.
- The well trajectory input table is for the well path above the reservoir section. Enter values down to the last survey point above the shallowest layer that you enter in the Layer Properties section (whether or not that layer is initially open or closed). Well path within the reservoir section is as defined by the Layer Properties (depths).
- ID is the ID above the reservoir section. For 2-7/8" monobore it's 2.441"
- Roughness is absolute roughness in inches (not relative roughness). Typical values: 0.00138" for normal tubulars and 0.00216" for 13-Cr.
- Suggest to make a simple 4-column Excel table, copy to clipboard, position the cursor on the top left blank cell of the Data Entry table, and use the "Paste" button.
- Then click apply

Layer Properties

Suggest to create a table in Excel that contains all the required info. It's easier to edit in Excel than entry-by-entry in the table. There is no maximum to the number of layers that can be entered

Comments:

- If there is a currently/initially unperfed layer you should include it but leave it closed in the Layers Status tab.
- TVD is referenced to RT (KB) not SS
- Top (MD) and Bottom (MD) refer to the perforation intervals which of course might not be the same as the reservoir thickness. If there are multiple sets of perfs within a given layer, suggest to use the top depth of the top one and the bottom depth of the bottom one. The software assumes that each layer entered communicates only via the wellbore, so entering hydraulically-connected perforation intervals as separate layers could produce anomalous results.
- Top TVD and Bottom TVD are referenced to RT not SS, so if you have a petrophysical summary which gives only the SS top you will need to:
 - o Make sure the TVD is a positive number (SS depths are often expressed as negative numbers)
 - o Add the RTE
 - o If you don't have a bottom TVD depth, just use Top TVD + True vertical Thickness (TVT). This is an oversimplification but won't usually make much difference
- TVT: use the net thickness. The layer GIIP is calculated based on this TVT entry so using a gross TVT will overstate the GIIP
- Porosity and Sw must be entered as fraction, not whole (percentage) numbers.
- k (mD) is obviously permeability. If values are not available suggest to use the results of a suitable k-phi transform.
- D is the non-Darcy skin factor expressed in (MMscf/d)⁻¹. Unless you have a good idea what this is we suggest to leave it at zero. With multiple commingled layers the contribution from

each layer is typically not large enough for non-Darcy skin to be a major issue, unless the drawdown is very large.

- Area in acres: this is the key parameter which will be used later for matching the model to the real-world MPLT/SIP results. Most of the time this is an unknown. For Gulf of Thailand applications you would probably start by using the Inferred Area for the platform/fault block for all zones.
- Pi (initial pressure) – usually from wireline formation tester measurements if available, otherwise from pore pressure gradient or offset well information.
- CO₂, CGR and gas gravity may not be known by layer. If they are not, you can use an average or make some assumptions about layer properties (e.g. if there is a known CO₂ trend with depth). Measured wellhead gas properties may change over time as the proportional contributions of different layers change; the CWM will track this but obviously this doesn't give any useful info if an average is used for all layers.
- WGR in bbls/MMscf. Hopefully it starts at zero ... Layer WGR can be adjusted over time in the Layer WGR input tab.
- Skin: layer skin is entered for each layer and each timestep in the Layer Skin input tab.

Gas Properties

- Gas properties are assumed to be uniform between layers. You'll need to estimate an average SG and inerts content and an average base temperature. The applicable values for each layer are then calculated based on the prevailing layer or wellbore P&T .
- Note that inerts content is entered as a fraction.
- If Z_g or M_{ug} is known from lab measurements, a shift can be applied to match the correlation data to that measurement.

Production History

- If the Production History is more than a few steps long (and there is no limit except in terms of practical calculation time to the number of timesteps), suggest to create an input table in Excel and paste it in.
- Because the inflow equations are PSS-based, the solution will be approximate for very short timesteps (depends on layer size and permeability).
- For ease of calculation it's suggested to average long periods of production rather than entering day-by-day allocated values out of the production monitoring database.
- FTT (flowing tubing head temperature) is used to calculate the tubing temperature gradient during the timestep (based on a linear interpolation from bottom hole to surface). If it's not well known suggest to use a simple approximation, e.g. 85 deg F when the well is shut in and 140 deg F when it's flowing. The main significant impact this parameter has is on the calculated FTP.
- FTP (flowing tubing head pressure). This parameter serves one of 2 functions: either it is available to plot as a comparison/reality check with the calculated FTP when the matching parameter is flowrate; or it can be the matching parameter in which case flowrate will be the comparison/reality check

- Flowrate: self-explanatory – similar comments apply as for the FTP (previous bullet point). Note it is in MMscf/d not Mscf/d.
- Generally flowrate makes for a better matching parameter. This is because predicting BHFP based on FTP can have large uncertainty especially in the case of multi-phase flow. If an invalid/inaccurate slip model is used (and, let's face it, no slip model is universally valid), then the BHFP computed could be significantly off, resulting in a poor match of the total-well flowrate and invalid zonal contribution estimates. Since the zonal contributions and associated material balance are what drive the evolution of rates and pressures, errors in BHFP will quickly stack up over multiple timesteps and lead to uncertain outcomes.
- By matching on flowrate, uncertainties in the slip model have a major impact only within the reservoir section and will therefore have a smaller impact on calculated layer contributions. But using the FTP as a reality check may allow subsequent tuning of the slip model.
- The FTP constraint is intended to capture real-life conditions, i.e. that the well has to produce into a production manifold operating at some specified pressure.

Layer Status

- This feature is useful when not all perforations are made at the same date, or when zones are plugged back or shut off (e.g. for water shut off purposes, or for temporary installation of a standing valve to prevent downflow).
- Generally it's easiest to click on "Populate all" and then click to clear individual layers that are closed in at certain times.

Layer Skin

- Generally this is an unknown. One valid approach would be to use an expected skin value, based on local experience for the completion method used.
- The SIP matching routine incorporates an option to adjust either skin (holding permeability constant) or permeability (holding skin constant) to match the zonal Productivity Index obtained from the SIP analysis.
- Skin can be varied with time. It is highly unlikely that the skin is known on a layer-by-layer and timestep-by-timestep basis. However there may be circumstances (e.g. if a baseline MPLT survey is performed, or a single-sand PBU, allowing comparison with results from a later SIP analysis) when the PI of a layer is seen to have changed. In such cases the user will need to use his or her judgment concerning how the evolution in skin happens over time. For the base case and in the absence of other information, assume constant skin.

Layer WGR

- In most cases the WGR will be known on a per-layer basis only after an MPLT has been run. With this info, and the observed time from routine well tests at which the well's water cut started to increase, the Layer WGR can be populated by timestep.
- If WGR is > 0 then there will be water hold up ($Y_w > 0$) within the reservoir section. This affects the pressure drop between layers (as well as back to surface).
- For the time being the CWM does not reliably converge unless slip velocities are set to zero (*this problem has been improved in v2.2 but not yet wholly solved*), so the Y_w in regions of the well where $V_m < V_{Turner}$ will be underestimated.

- The CWM estimates the water vapour content and condensed water production from each layer based on the reservoir pressure and temperature. So the total-well water rate will not necessarily be zero even if the Layer WGR is set to zero for all layers and all timesteps.

Match Flowrate or Match FTP

As discussed earlier, it is usually preferable to match the flowrate history rather than the FTP (Flowing Tubing-head Pressure) history, and to use the latter as a quality/reality check on the well pressure drop prediction.

The command to perform the match is accessed via the Project menu:

Project → Match Flowrate

Once the match is complete the results are brought up automatically in the Output Summary tab.

Main Plots

Key well parameters (total flowrate and Pwf and FTP) and key zone parameters (zonal rates and pressures) are automatically plotted against time and are available to view in the Main Plots tab.

The plot can be zoomed in interactively using the cursor with a left click, and a plot menu (including un-zoom) is available via a right click of the mouse.

Detailed Calculation Results

Under the Report menu is an option called Calculation Results. This provides the detailed results of calculations of every parameter, at every calculation node and every timestep. This detailed listing can be very useful for understanding anomalous results or for troubleshooting non-convergence situations (e.g. where the CWM cannot match the specified flowrate in a given timestep). It can be saved outside the CWM Project into Excel format.

Custom Plots

Custom plots can be created for a large range of parameters via the Custom Plots tab. The plots can be created against depth, to give a snapshot of the well condition in a specified timestep; or against time for the entire production history.

The plots can be zoomed and un-zoomed, and there is also the facility to display the plotted data in tabular format and to save to file or to copy to.

A versus-depth plot of mixture velocity and Turner velocity is often interesting, as it allows easy identification of the section of the wellbore that is at risk from load up (if liquids are present).

The various plots provide an easy way to picture how the well performs over time, or to forward-model and compare various different completion scenarios and play what-if games by varying the input parameters and quickly generating alternative outputs (plot images can also be saved to the clipboard for comparison purposes). In this way the CWM functions as a quick and easy Initial Completions planning tool. This is what might be termed the predictive function of the tool.

SIP Matching

The SIP matching routine, on the other hand, represents a key analytical function of the CWM. The methodology provides a way to understand how the GIIP associated with a well is distributed among the separate perforated intervals, and also to compare the “measured” PI from a PL survey with the expected PI based on the permeability and skin input into the model. The way these functions are achieved will become clear as we follow the workflow.

The starting point for the SIP matching is to have an external¹ data set which provides the following information for each layer:

1. Current average reservoir pressure²;
2. Productivity Index (in MMscf/d/psi or Mscf/d/psi)³

Traditionally this type of information would come from a multi rate PL survey, typically with 3 flowing surveys at different rates, and a shut in survey. However any type of survey that provides those 2 pieces of data will be OK – albeit potentially with lower accuracy/reliability. For example:

- A 2-rate (e.g. single flowrate plus shut in) PL survey. The same information is obtainable from a standard 2-rate survey as from a multi rate survey. The results are generally lower confidence: 2 points can always be joined by a straight line, but then we have no information concerning the uncertainty in the SIP results;
- A set of interpreted flowrates from fibre optic (DTS) survey data at multiple flowrates (not separated by significant time intervals), together with a pressure data set either with direct measurements of pressure at each layer (preferred) or with a single point pressure that has been depth-corrected to provide a pressure opposite each layer at each flowrate of the survey. The latter method is likely to be inaccurate in multi-phase flow since it relies on a good understanding of the sources of water production, and a reliable slip model that robustly predicts phase hold ups.

Once the SIP results are available, the workflow proceeds through the following stages:

1. Click the “Enter SIP Analysis results” button

¹ i.e. this information is from the well we want to analyze; it is not generated internally by the model (except in the case where we want to use the CWM to generate a synthetic data set which we can then “practice on”)

² The validity of the SIP technique for determining average reservoir pressure warrants discussion. However this is outside the scope of this workflow/guideline.

³ The PI is assumed to be linear. Of course this is not strictly true for a gas reservoir, but in this application the errors introduced by neglecting the non-linearity are not expected to be large. See earlier comment concerning non-Darcy skin.

2. Define the number of SIP data sets you wish to enter. In the case of a simple 2-rate survey this will be, well...obviously, 2.
3. Specify which timesteps in the production history correspond to the SIP data sets
4. Enter the average layer pressures (psia) and PI (Mscf/d/psi) from the SIP analysis
5. Enter the Pwf opposite each layer for each of the SIP data sets, and the gas flowrate from each layer (Mscf/d/psi) – or, in the case of crossflow, into each layer (in which case the flowrate has a negative sign).
6. Click OK
7. Select the SIP data set whose flowrate you want to match (generally this will be the maximum rate survey, depending on data quality)
8. Click on the “Adjust Layers PI” button and select the SIP data set that you want to match to (usually the maximum rate of the PL survey).
 - a. The table which appears will have the SIP PI for each layer (i.e. the values that you entered in step 4 above), and the permeability for each layer (pulled from the layer properties table) and the layer skin (pulled from the Layer Skin entry for that timestep).
9. Click on Calculate Layers Productivity Index and a PI will be calculated based on the k & S (as in Step 8a above), and the h and inferred Re/Rw from the Layer Properties input table.
10. You can then choose whether to adjust the skin or the permeability to in order to get the SIP PI & the calculated PI to match – usually the adjustment will be on the skin. You can then assign that skin value to all timesteps (the most common approach) or just to the timestep corresponding to the selected SIP data set.
 - a. Following this step you have matched the layer productivity index in the CWM with the layer PI from the SIP results. The next step is to match the GIP:
11. Next select (again) the SIP data set from the drop down menu. In the resulting table the layer area (as entered in the Layer Properties input table) is displayed. If you then press calculate the CWM will run through input production schedule, and display 3 panels in which the input SIP results (i.e. from the external PL survey, entered in steps 4 & 5 above) are compared with the values calculated by the CWM for the specified SIP timestep.
 - a. Note that you can zoom on the plots in order to magnify the matching
12. **Suggested Methodology for Matching Areas** (remember that area is our matching parameter but in reality it is a proxy for GIIP). There is no obligatory approach, but the following generally seems to work:
 - a. **Focus on the Gas Rate panel.** If the Model (blue) bar is too big, it means the area used is too big. Quickly go through and make a first pass adjustment to all zones, reducing or increasing the area by the proportional mismatch in the panel (so if the first zones SIP bar is 40% of the size of the Model bar, reduce the first zone’s area by 60%, etc etc). Don’t be too precise here – further adjustments will usually be necessary. Start with the bottom zone – since starting point for calculations is the Pwf at that zone which you entered in the SIP results.
 - b. **Next focus on the 2 zones with the highest rate** and get a match on them to within about 10%
 - i. You can use the automatch feature (with regression on one Layer at a time) initially and then refine it manually.

- ii. You will notice that changing the area of one layer affects the match of all the other layers. This is because the contributions from all the zones will have to change over the entire production history in order to compensate for the change in contribution from the Layer whose area you have just varied. This is why there is no point in focusing on one layer at a time from the beginning and seeking a perfect match for it ... The match will be thrown off as soon as you go to the next layer.
 - c. **Then go through and adjust zone by zone from the bottom zone up.** If the match on the gas rate is slightly off in one direction (Model too high, say) but the match on the Average pressure is slightly off in the other direction (Model too low), then don't make any adjustment.
13. With a bit of practice you can generally expect to match the areas of all Layers in a 6-Layer well model to within 20% after about 5 iterations. 10 iterations should get you within 10%.
14. Don't forget, however, that getting a good match in your panel, and being within a few percent of the correct area with a synthetic data set, does not mean that you are that close in the real world. Many real-world effects can impact the quality, including:
- a. Poor quality PL data and/or long extrapolations to get average pressures from the SIP.
 - b. Changing skin (yes, skin can be varied with time in the CWM but in the real world you won't usually have the info needed to define where skin is changing and exactly when).
 - c. Aquifer support
 - d. Water in the wellbore

