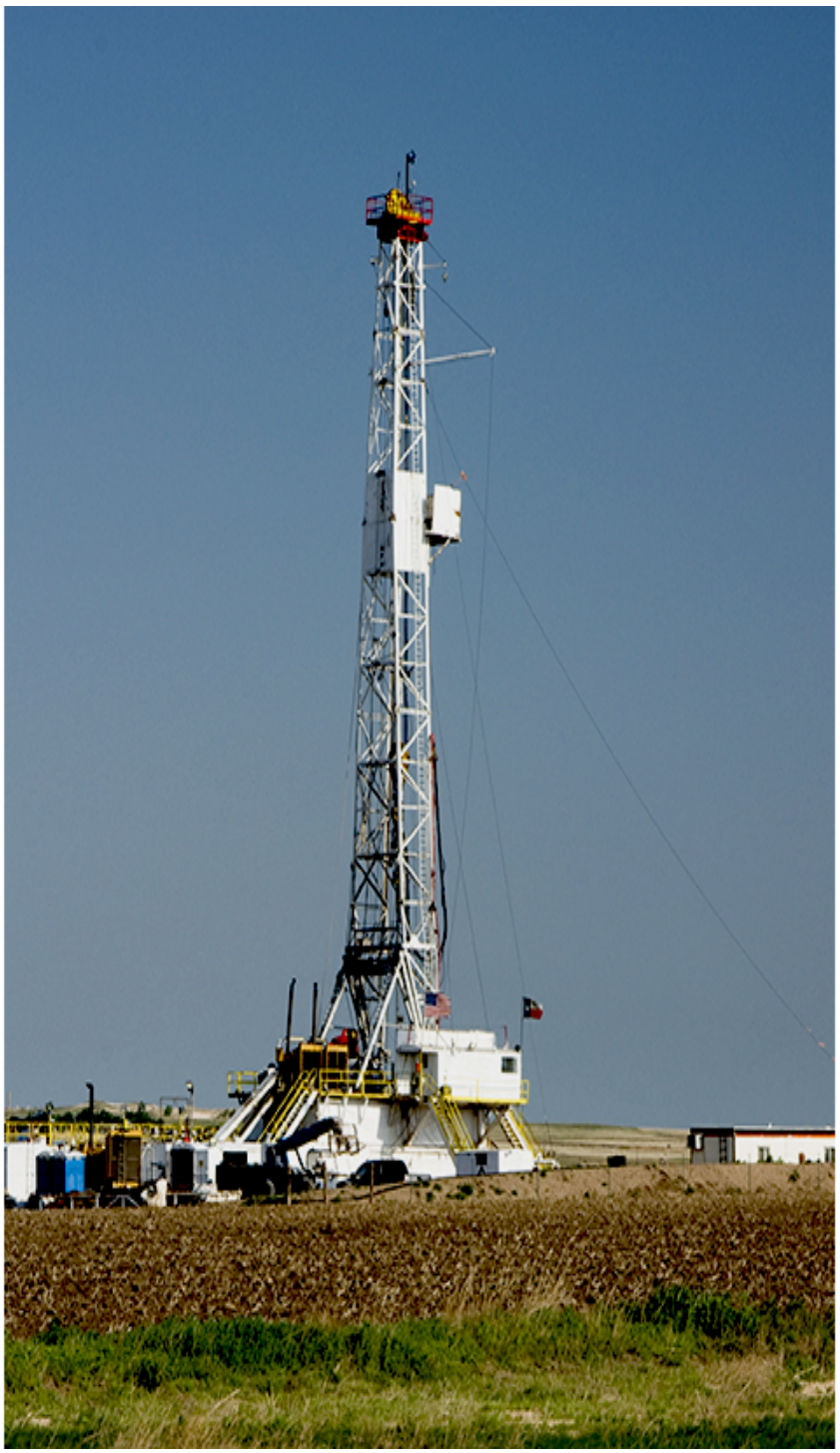
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Piper™ 2018.1 Help – PDF

Last revised: 4/6/2026







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

About Piper

- Overview
- Navigation
- Licensing

Procedures

- Building a model
- Calibrating a model
- Forecasting gathering systems
- Validating forecasts
- Adding changes after building a model
- Optimizing a model

User Interface

- GIS
- Forecast view
- Case controller
- Production plotting
- Editors
- Menus
- Toolbars

Reference Materials

- GIS theory
- Reservoirs
- Well deliverability
- Surface facilities

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About Piper

About Piper topics include the following:

- Overview
- New project
- Existing project
- Navigation

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Overview

Piper® is a pipeline, wellbore, and reservoir deliverability modeling tool that enables you to optimize both existing and proposed gathering systems. Prior to committing to capital expenditures, Piper is used to test gathering system scenarios to make sure that optimizations are cost effective and increase deliverability.

Gathering System Analysis

Piper solves complicated gathering system designs and operating scenarios. Gathering system models are created using drag-and-drop techniques. Your system is referenced to the correct geographic information system (GIS) location, and shapefile and image file imports let you view the topography of the area. Piper can also be used to identify system bottlenecks and model the impact of new wells, compressor changes, line loops, and system interconnections for either single-phase or two-phase flow.

Note: Piper can load Harmony Enterprise™ and Harmony™ files and extract reservoir parameters for full-field forecasting and development planning.

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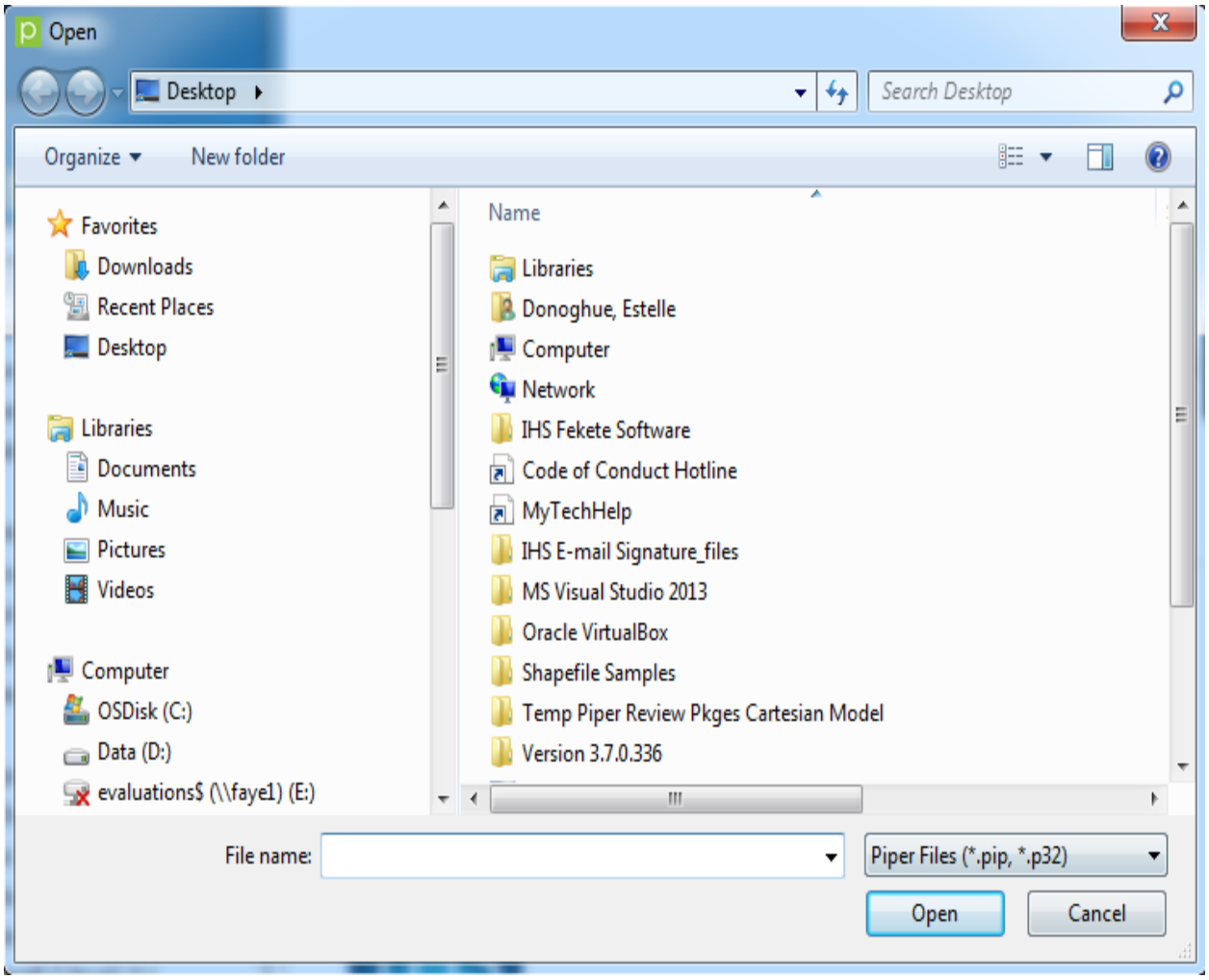
New project

From the Piper startup screen, you can select **New Project** to create a new gathering system model in two different modes:

1. Cartesian Mode
2. GIS Mode

Existing project

If you select **Open Existing Project**, you can select an existing Piper file.



After a file is selected, it is launched and opened in Piper. For more information, see working with an existing model.

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Navigation

These terms apply to the instructions given in this help:

- Click: means click the left mouse button
- Right-click: means click the right mouse button

GIS toolbar icons

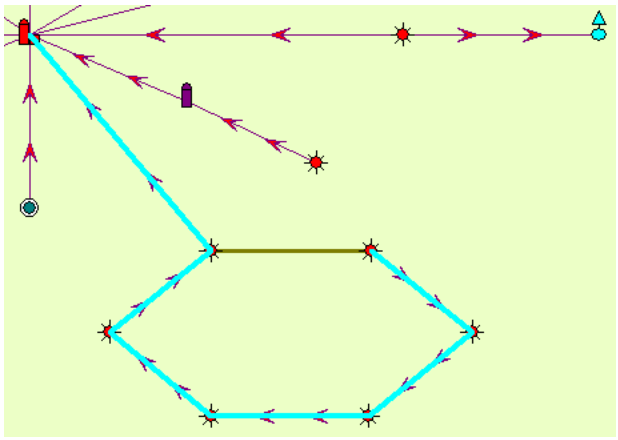
Navigation icons are located in the GIS toolbar, directly above the map, and these apply to all of the map screens:

-  + click: Zoom in
-  + right-click: Zoom out
-  + drag click: Pan
-  Reset GIS: Note that this zooms to extents.
-  Selection pointer: Single or group selection is available. For group selection, you can select by:
  - Area (right-click and drag for a rectangular box selection around the facilities you want to select)
  - Lasso (right-click and drag to draw a free-form polygon around the facilities you want to select)
    Note that the selection pointer needs to be reselected after selecting any of the GIS icons.

Shortcut keys

- Esc: resets the mouse to the default pointer (instead of link connections, reconnect, drawing a facility, zooming, panning)
- Shift + right-click: Zoom in
- Shift + drag right-click: Zoom in on rectangle
- Ctrl + right-click: Zoom out
- Shift + drag click: Pan
- Ctrl-L: toggles link highlighting

Ctrl-L toggles link highlighting on / off. When this is turned on, links will appear as blue lines that trace their way back to the plant. In the case of a loop line, it shows an orange line in addition to the blue line which represents the different pathways that can be taken to get to the plant. The blue line is drawn first, so if there does not seem to be a blue line to the plant, it is being obscured by the orange line.



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Licensing

There are two types of Piper licenses.

A standalone license is installed on your local machine. For information on standalone licensing, see activating / deactivating your license.

A network license is installed on a network server and Piper must be configured to 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. For information on setting up network licensing, see the S&P Global Installation Guide and License Manager help (both links open in a new window / tab).

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Activating / deactivating your license

For standalone licensing, you only need to install Piper.

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 S&P Global 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 Piper. Do not activate licenses using the EMS Customer Portal unless instructed to do so by a customer care representative.

Activating / deactivating your standalone license

To activate or deactivate your standalone license:

1. Open your EMS - Entitlement Certificate email and copy your entitlement ID (EID).
2. Start Piper.
3. Open the Licensing dialog box by clicking the **Help** menu and selecting **Licensing**.
4. Click the **Activate / Deactivate** button.
5. Paste your EID (from the email) in the Entitlement Id field and click **Connect**.
6. To activate your license, in the **Activate tab**, select the product you want to use and click the **Activate** button.

   Your license is now active.

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

7. To deactivate your license, click the **Deactivate tab**, select the product you want to deactivate and click the **Deactivate** button.

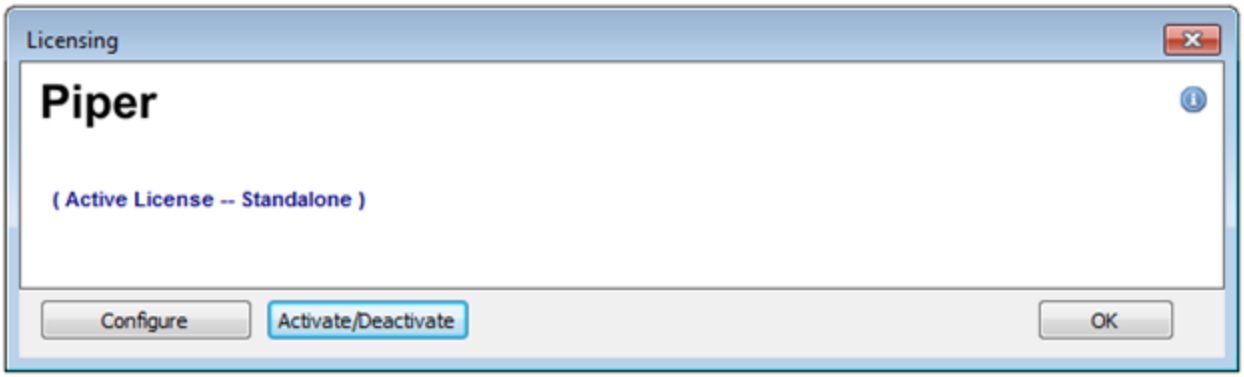
   The product is now displayed in the Activate tab and can be activated on a new machine.

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



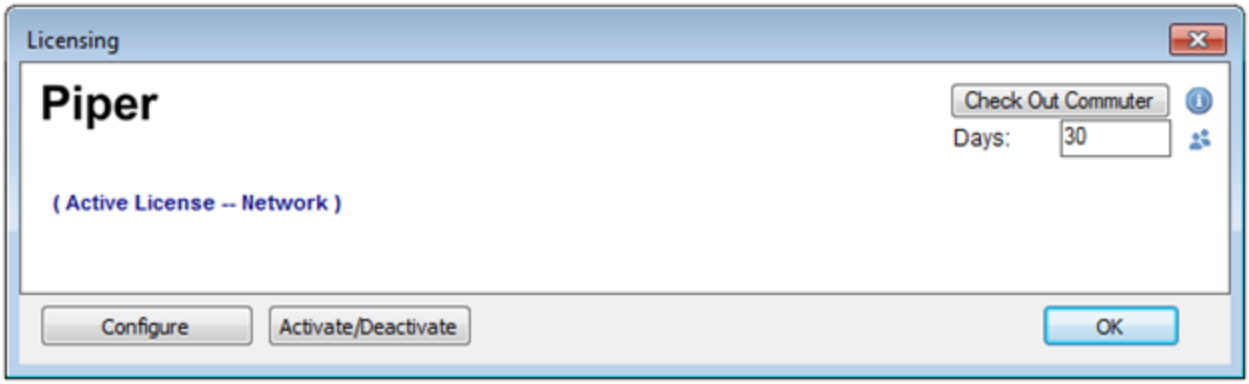
Active License -- Standalone — indicates that your license is ready for use. Note that if your license is not active, errors are displayed for troubleshooting purposes.

Information icon — opens the License Information dialog box.

Configure — 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 — opens the S&P Global 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.

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.

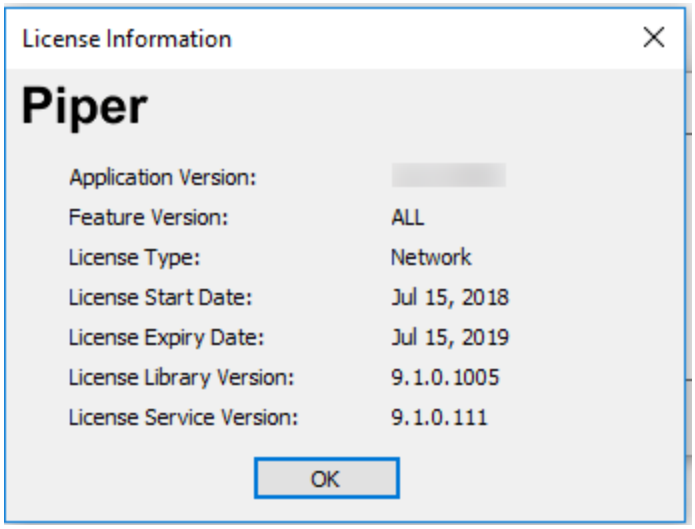
Note: This icon may be hidden by your administrator.

Configure — 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 — opens the S&P Global Online Activation dialog box where you can activate and deactivate your licenses.

License Information dialog box

This dialog box is accessible from the Licensing dialog box.



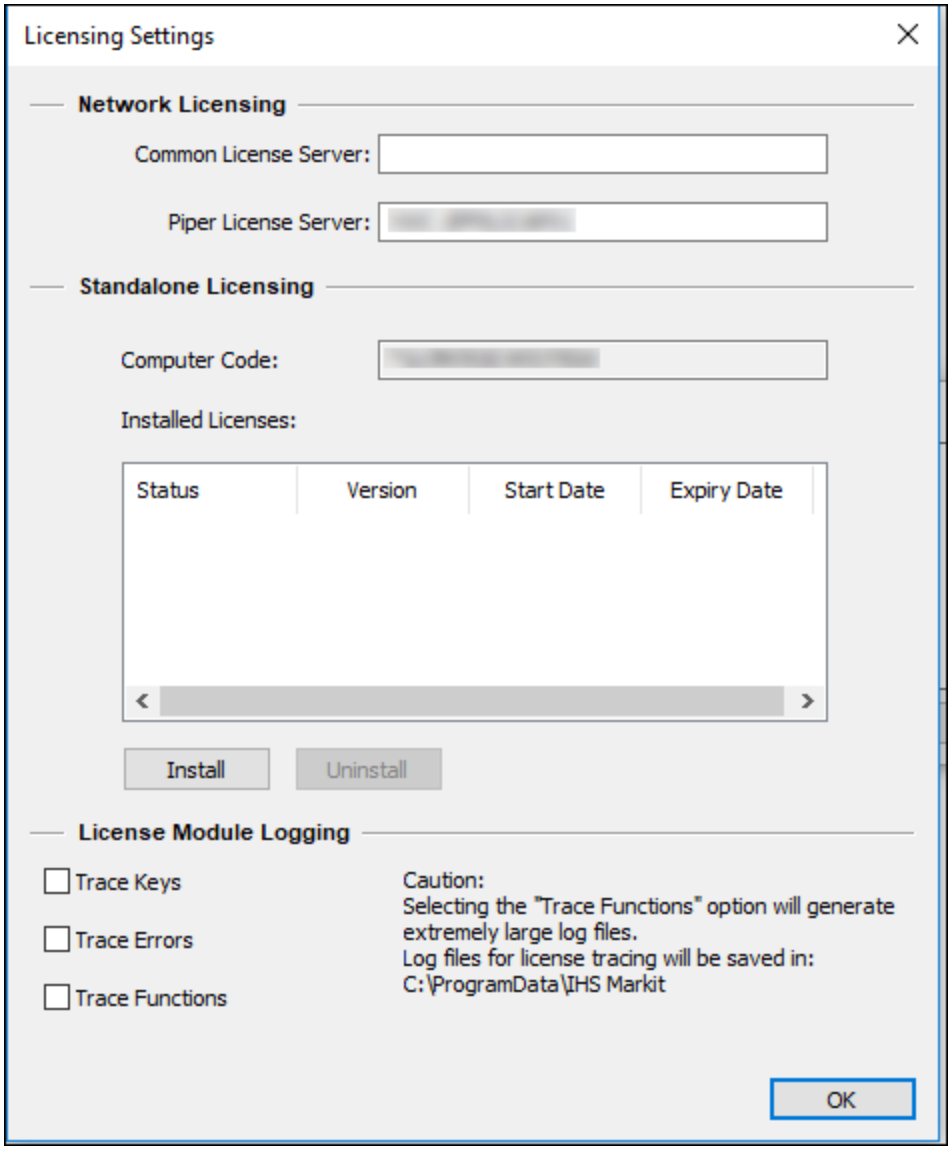
At the top, the name of your licensed module is displayed. Beneath this, the following information is displayed:

- **Application Version** — the build number for Piper.
- **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 Piper compatible with the Gemalto licensing system.
- **License Type** — indicates a network, standalone, or commuted 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).

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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 S&P Global 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 Piper and other S&P Global applications, use the Piper License Server field.

Note: If you fill in both fields, the Piper 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.

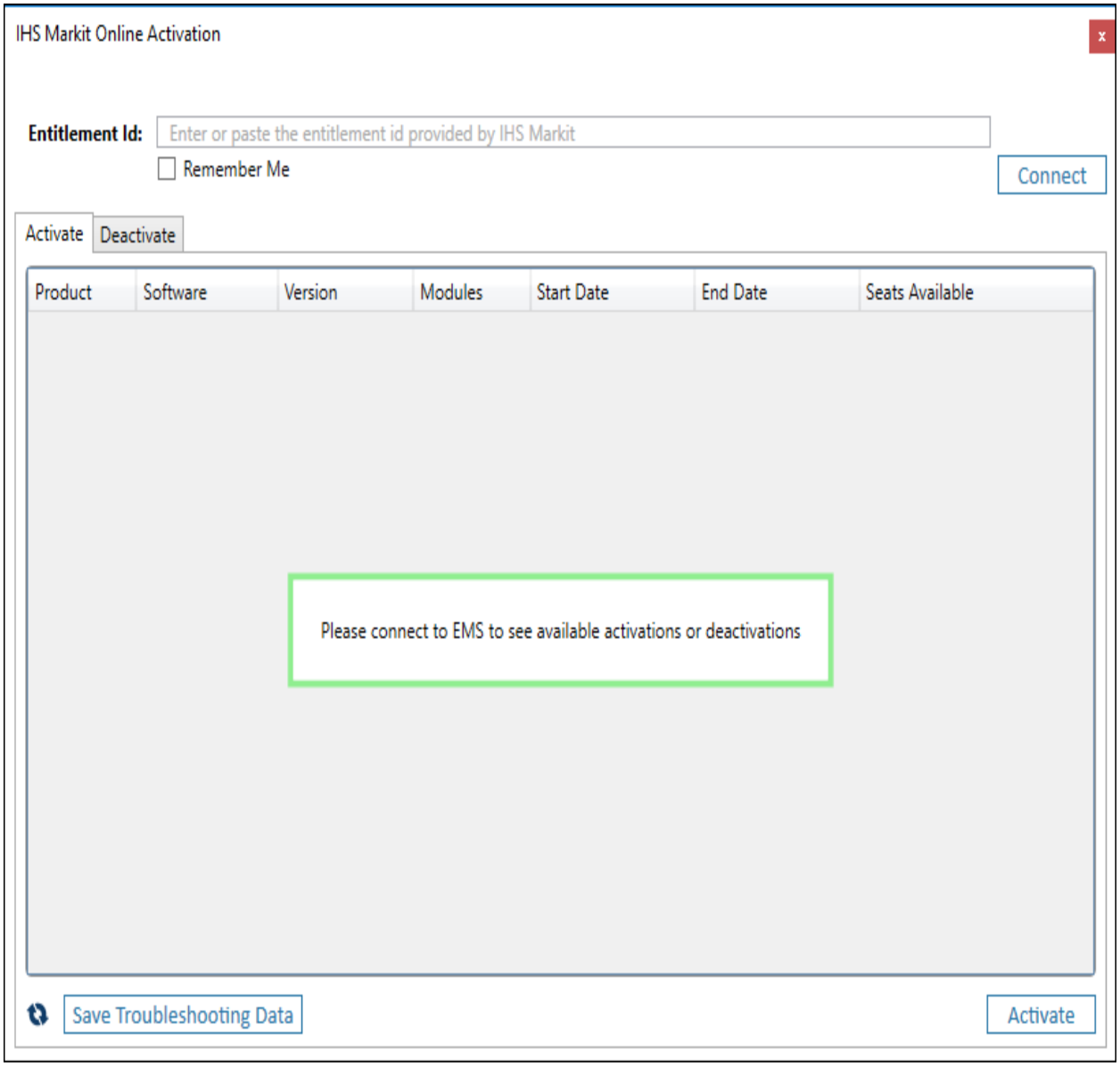
Uninstall button — if you want to uninstall standalone licensing on your local computer, click this button. Note that standalone licenses that are uninstalled with this button are not available for activation on other computers. If you want to move a standalone license to another computer, it must first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

License Module Logging

In the unlikely event of licensing issues, customer care may ask you to select one or more of these logging options. We recommend that these options remain deselected, unless you are actively investigating an issue.

S&P Global 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

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Procedures

Piper procedures include the following:

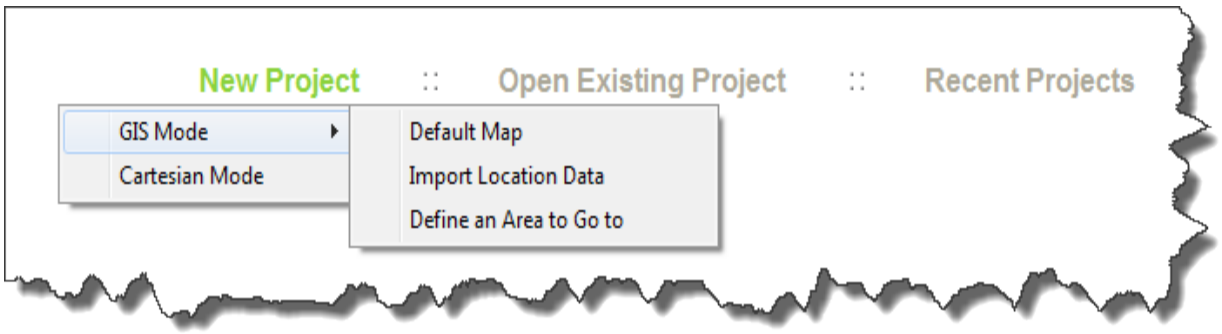
- building a model
- calibrating a model
- forecasting gathering systems
- forecasting injection systems
- validating forecasts
- optimizing your model
- using outputs
- adding economics
- adding changes after building your model
- creating a SQL database for Piper
- common importing tasks
- printing

Building a model

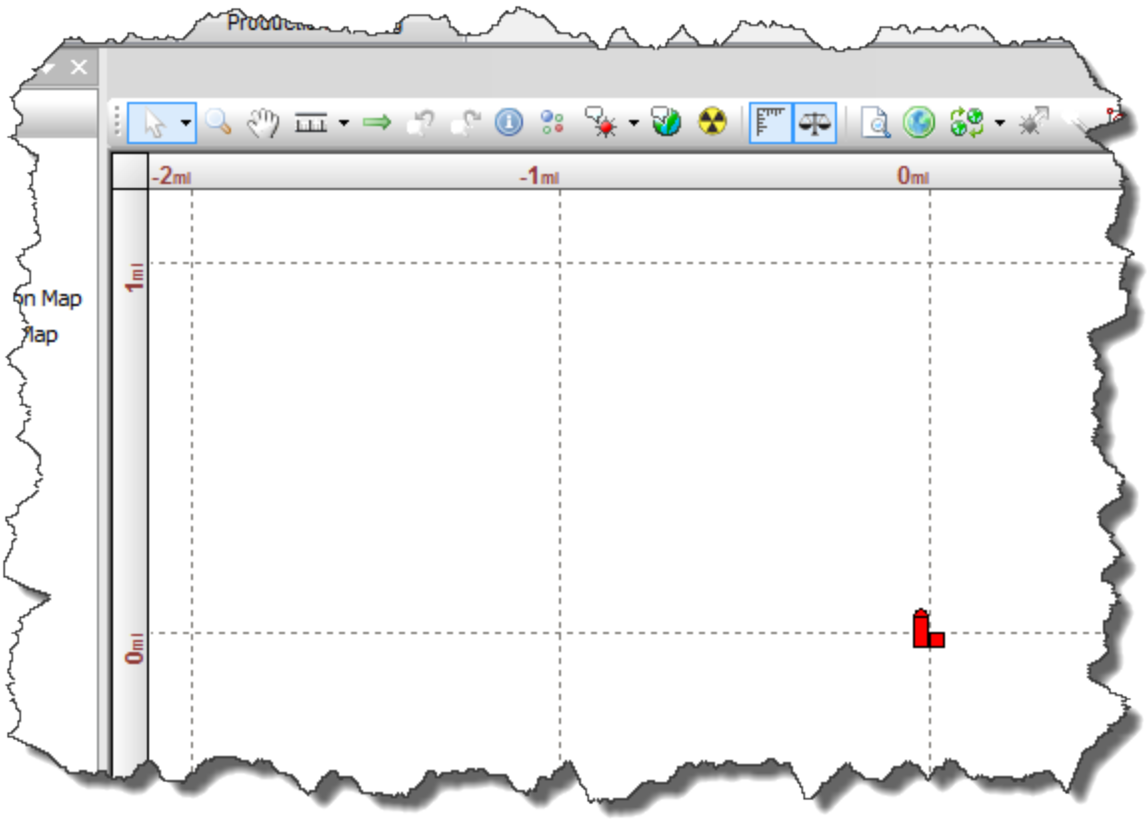
A gathering system model is used to represent field operating conditions. It is also used to identify system bottlenecks, and model the impact of adding new wells, compressor changes, line loops, and system interconnections for either single-phase or two-phase flow.

To build a model for your gathering system:

1. From the splash page when Piper is launched, click **New Project** and select either **GIS Mode**, or **Cartesian Mode**.



2. If Cartesian mode is selected, Piper opens with a delivery facility located at the origin (0,0) of the Cartesian grid. The gathering system can then be built from this point. Continue to step 4.



3. If GIS mode is selected, select from one of the following sub-options:
    - Default Map
    - Import Location Data
    - Define an Area to Go to
4. Add facilities. See these topics for additional information: name generator, compressors, separators, and pumps.
5. Add links. See these topics for additional information: editing link diameters, splitting links, optimizing loop links, and reconnecting links.
6. Add elevations.
7. Make sure your model is connected.
8. Add a temperature profile.
9. Set your correlations.

Once the gathering system model is in place, you can begin calibrating and running forecasts on your model.

If you want to model full compositions, surface losses, and/or working interest, click the **Forecast Options** menu and select the options you need.

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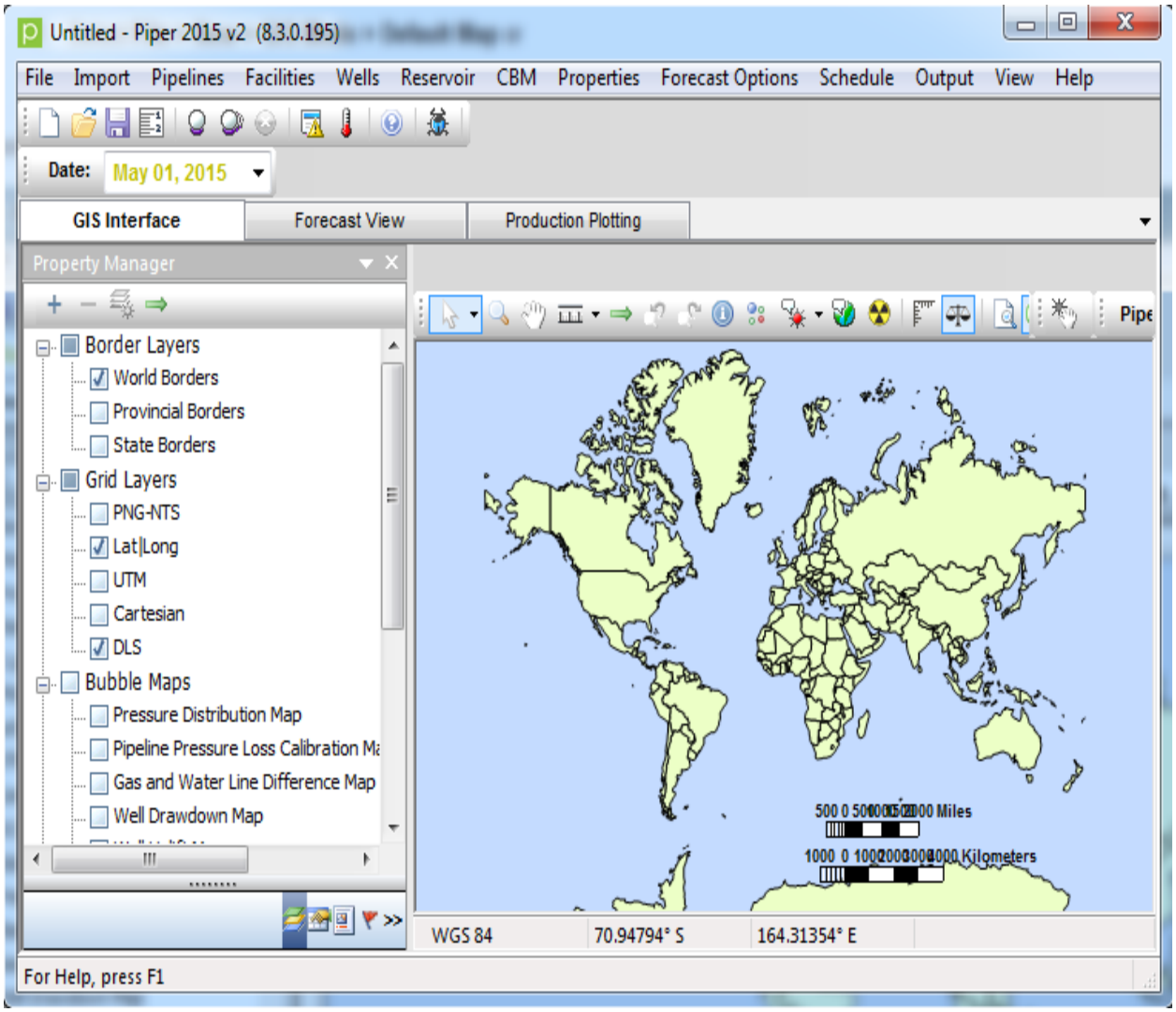
Default map

To view Piper in map mode (the default setting):

From the splash page, click **New Project** and select > **GIS Mode**.

Or, click the **File** menu and select > **New** > **GIS Mode**.

The default world map opens.



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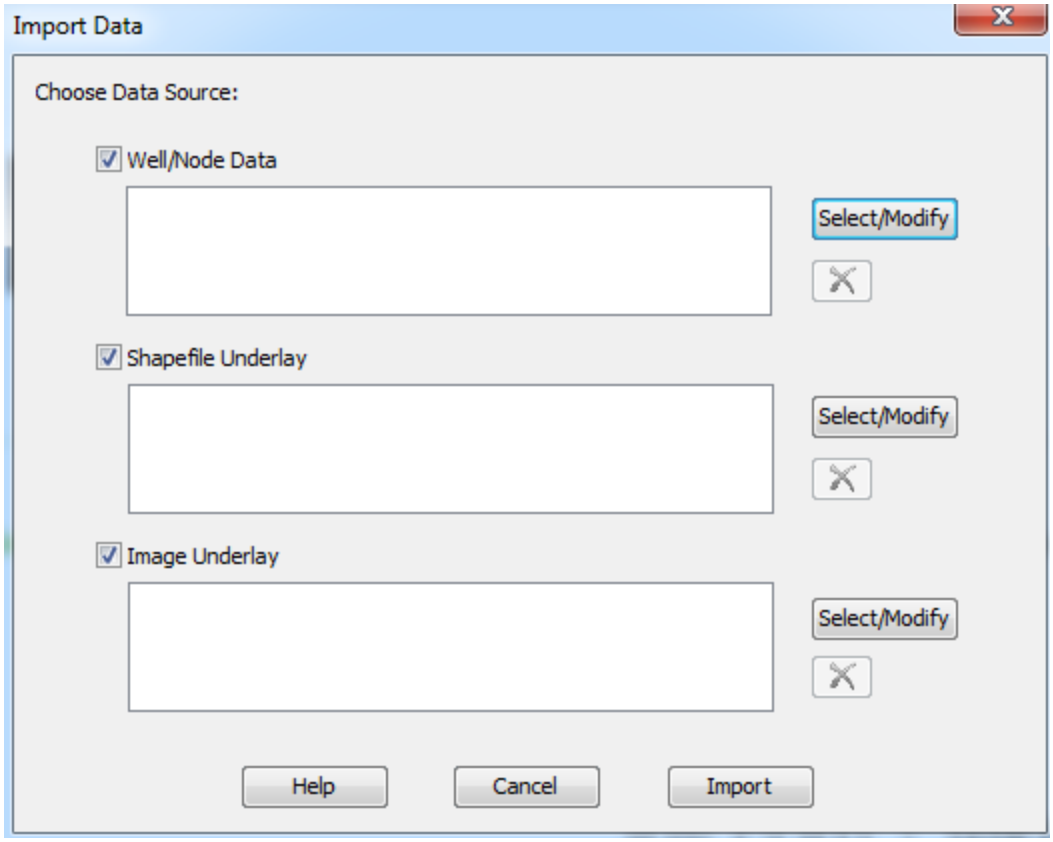
Import location data

To open Piper with specific location data:

1. From the splash page, click **New Project** and select > **GIS Mode** > **Import Location Data**.

   Or, click the **File** menu and select > **New** > **GIS Mode** > **Import Location Data**.

   The Import Data dialog box opens.



2. Click a data source that corresponds to the location data you want to import (Well / Node Data, Shapefile Underlay, and / or Image Underlay).

   The Select / Modify buttons for selected data sources are enabled.

3. Click **Select / Modify**.

   A dialog box specific to your data source selection opens.

4. Select the file(s) you want to import and click **Done**.

5. Repeat steps 2 - 4 for each of the remaining data sources, as needed.

6. Click **Import** when your data source selections are complete.

   For more information on importing data sources see:

   - For Well / Node Data, see Well editor or Node editor
   - For Shapefile Underlay, see Adding facilities from a shapefile or Adding links from a shapefile
   - For Image Underlay, see Image

   See common importing tasks for more information.

Define an area to go to

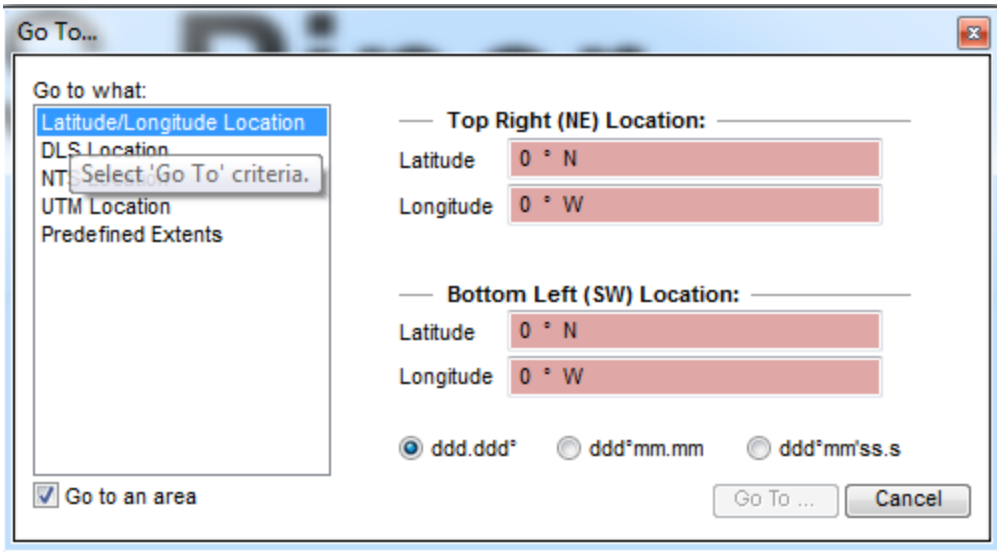
To open Piper to a specified area:

1. From the splash page, select **New Project** > **GIS Mode** > **Define an Area to Go to**.

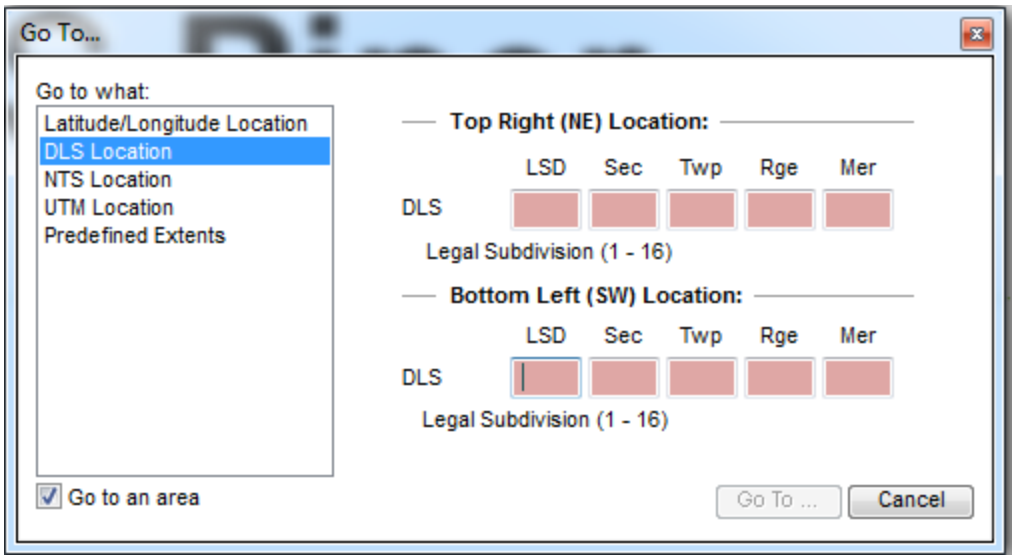
   Or, click the **File** menu and select > **New** > **GIS Mode > Define an Area to Goto**.

   The Go To dialog box opens. You can define the area by:

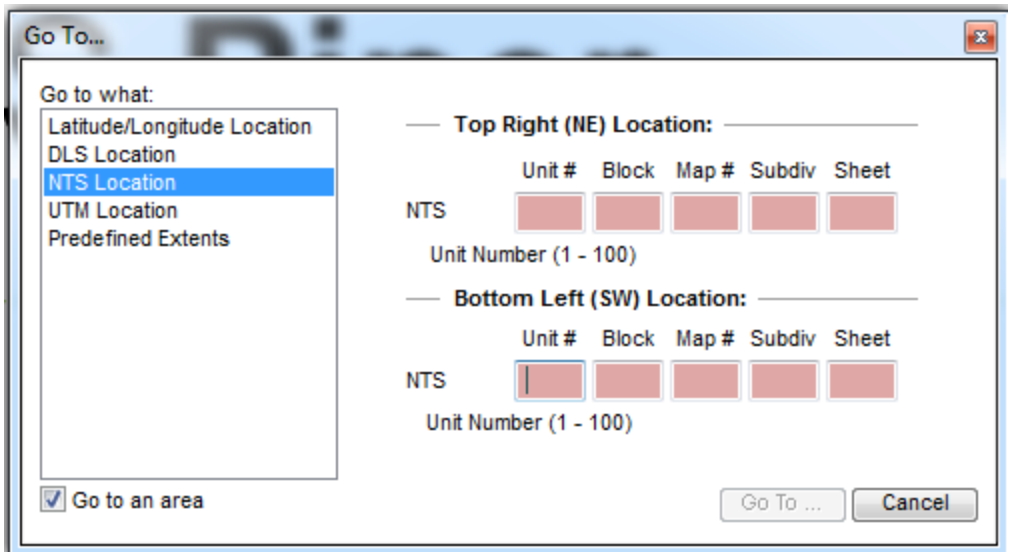
   - Latitude / Longitude Location



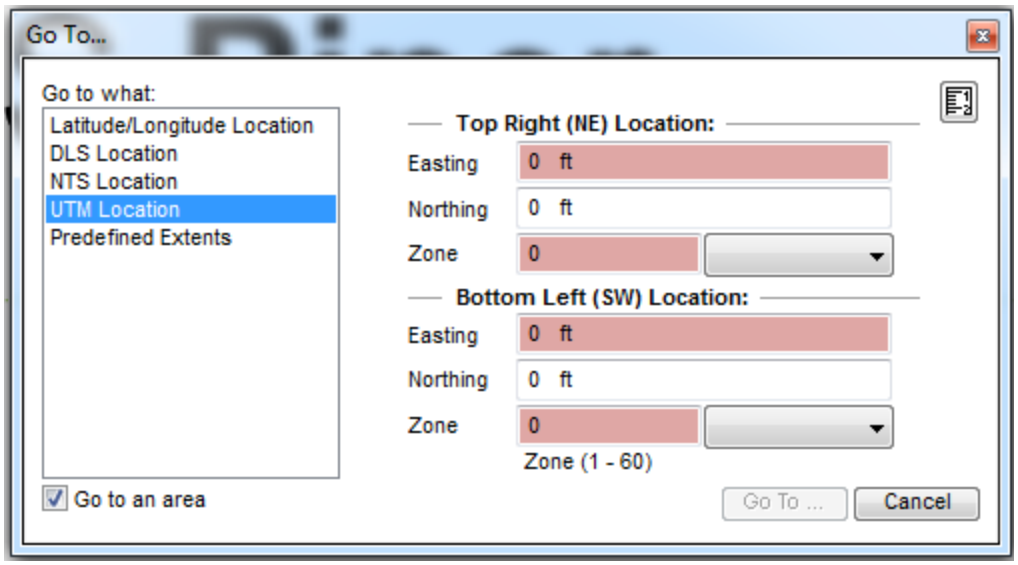
   - DLS Location



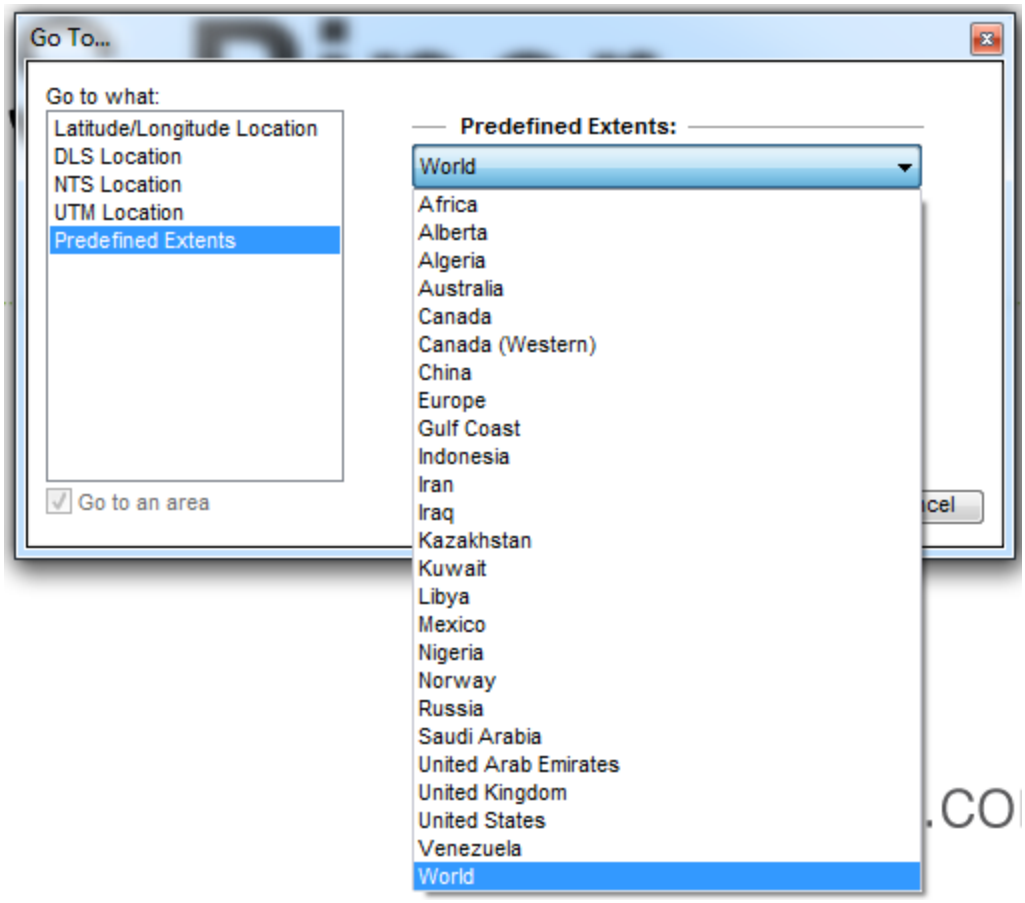
- NTS Location



- UTM Location



- Predefined Extents



2. Enter the information appropriate to the selection.

The Go To button is enabled.

3. Click **Go To**.

   The map displays the specified extent or location.

   For further information on coordinate formats, see GIS coordinates.

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Working with facilities

These procedures relate to working with facilities:

- adding facilities
- using compressors
- using separators
- using pumps
- using the name generator

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Adding Facilities

You can add facilities in Piper by:

- editing the map
- adding facilities from a shapefile
- converting nodes to facilities

Note: You can also add facilities by importing a location text or Excel file.

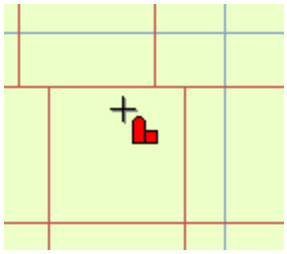
Editing the map

To edit the map:

1. Select the appropriate facility icon from the GIS design toolbar. The mouse cursor changes to the icon selected.



2. Click the map where you want the facility to be located.



   The facility displays on the map.

3. Repeat steps 1 and 2 to add other facility types.

4. Reselect the pointer icon from the GIS map toolbar () to exit design mode after edits are complete.

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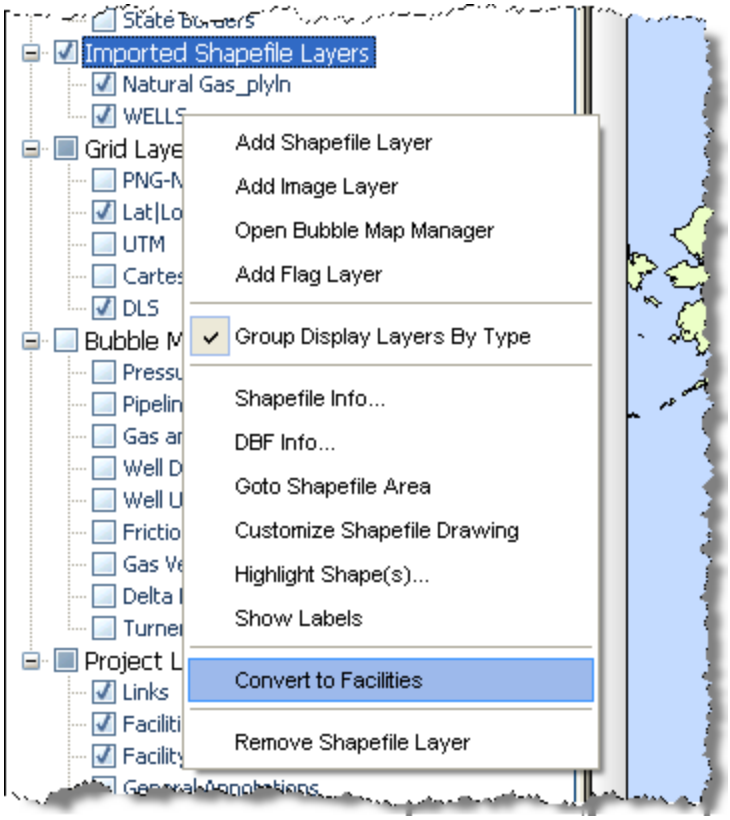
Adding facilities from a shapefile

To add facilities from a shapefile:

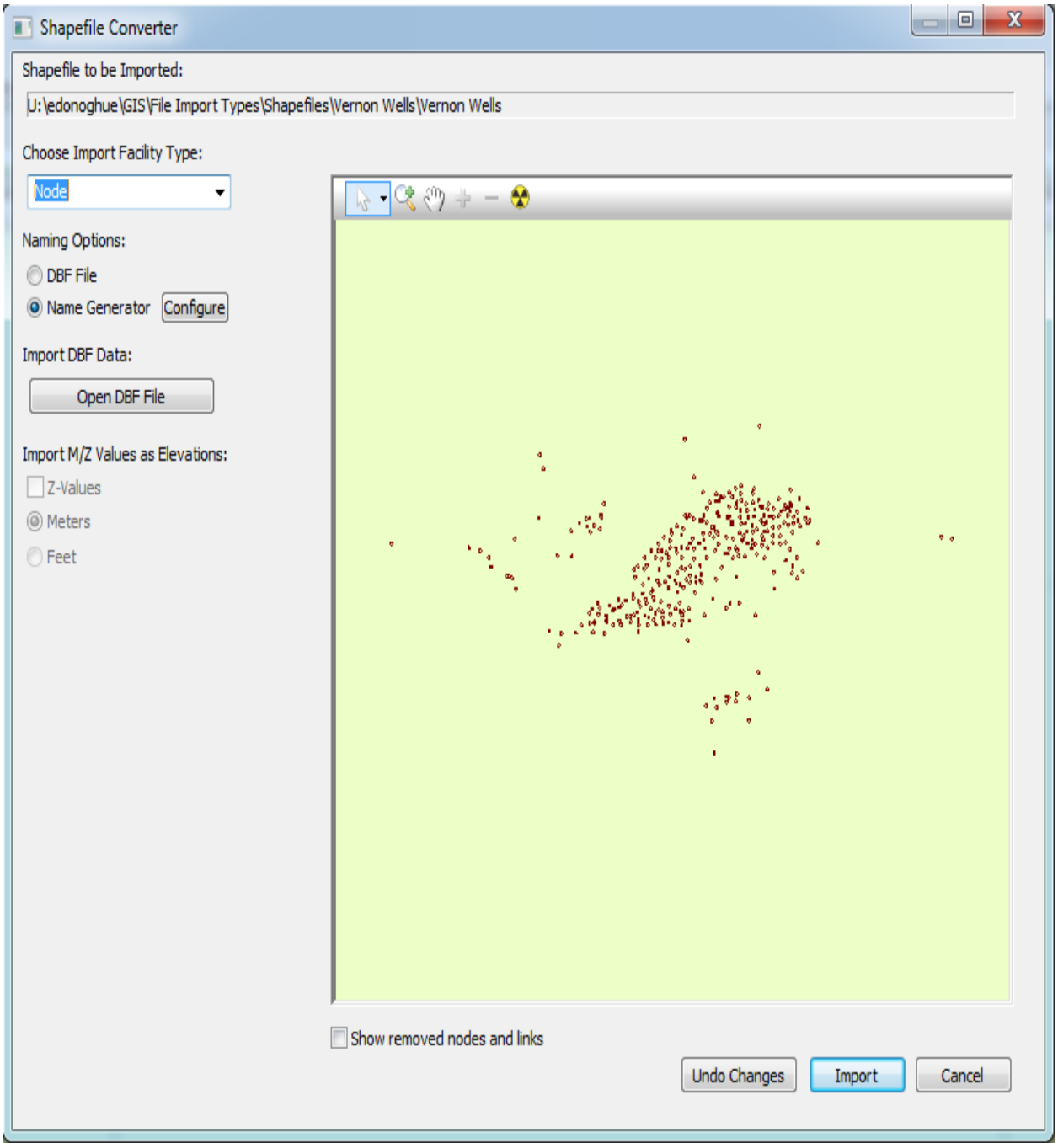
1. Import a shapefile.
2. Right-click the imported shapefile in the Property Manager and select **Convert to Facilities**.

   Or, click the imported shapefile in the Property Manager, click the **Layer-Specific Options** icon (), and select **Convert to Facilities**.

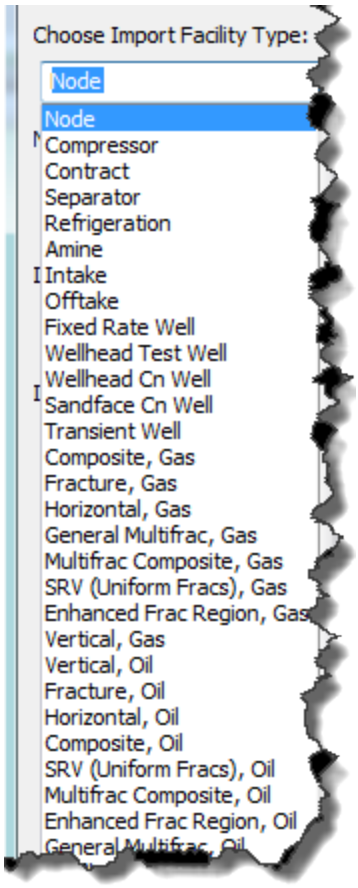
Note: For more information on shapefiles, see the ESRI Shapefile Technical Description at www.esri.com.



The Shapefile Converter dialog box opens.



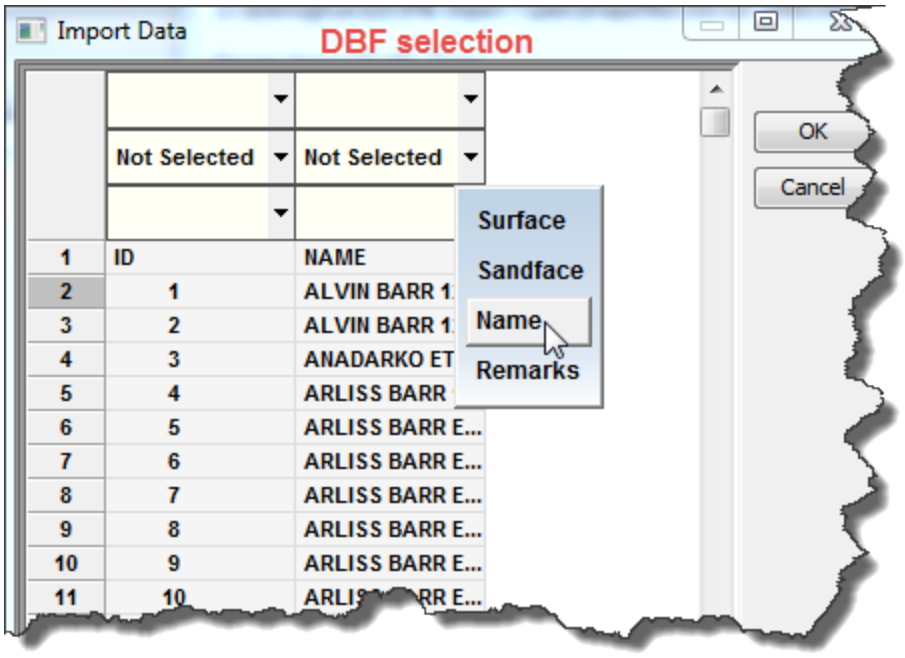
3. Select a facility type from **Choose Import Facility Type** for converting the shapefile.



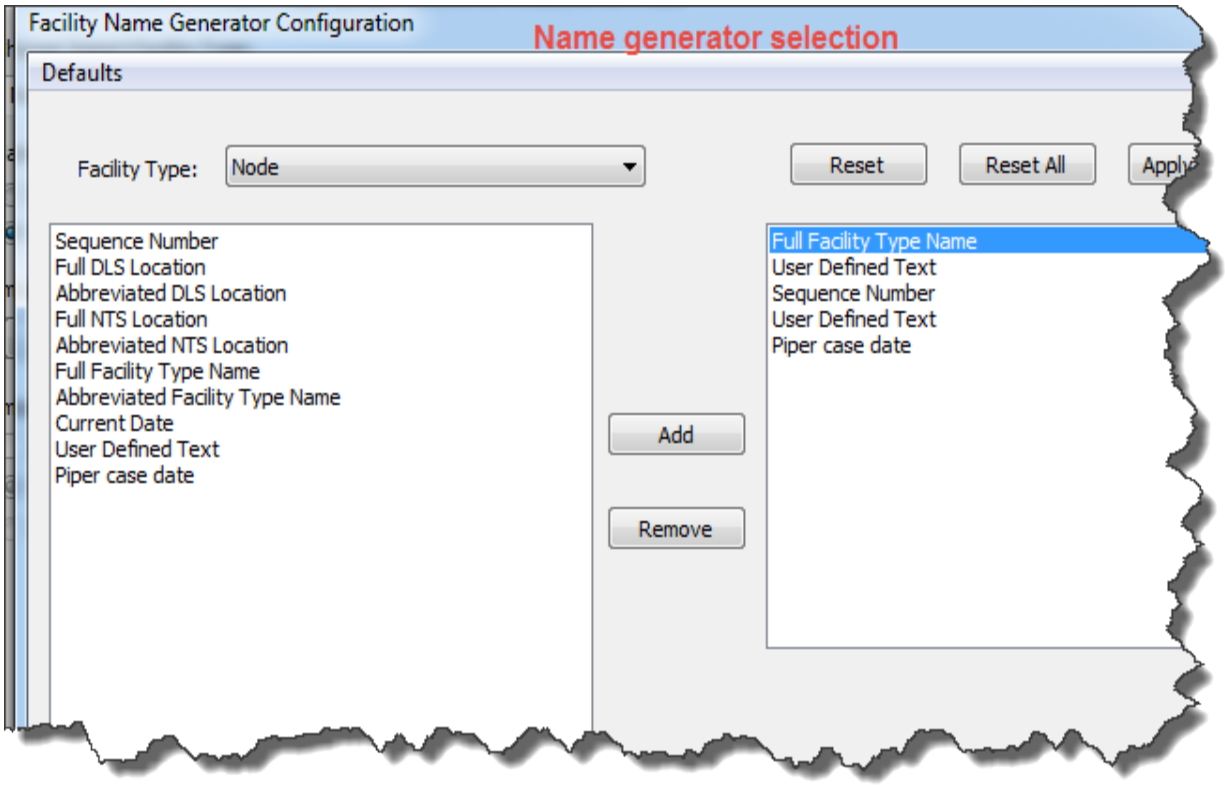
All shapefile points are converted to the selected facility type.

4. Assign a unique name to your facilities by selecting a naming option:

    - select **DBF File** and click the **Open DBF File** button to view the shapefile attribute data. Select a column to apply your name attribute to. For example, if column 2 is selected, your names are ALVIN BARR 1, ALVIN BARR 2 etc.



- or, select **Name Generator** (default setting) and click **Configure** to choose from a list of naming options.



5. (Optional) Click **Import DBF Data** to import other DBF attribute data. Select the data for import from the drop-down lists in the columns of the table.

6. Click **OK**.

7. (Optional) Click the arrow () icon to select any points you want to add or remove before converting.

   The selected points are highlighted in green, and the () icons are enabled.

8. To add or remove the selected points:

   - click the () icons to add or remove points
   - or, right-click the map and select **Add** or **Remove**



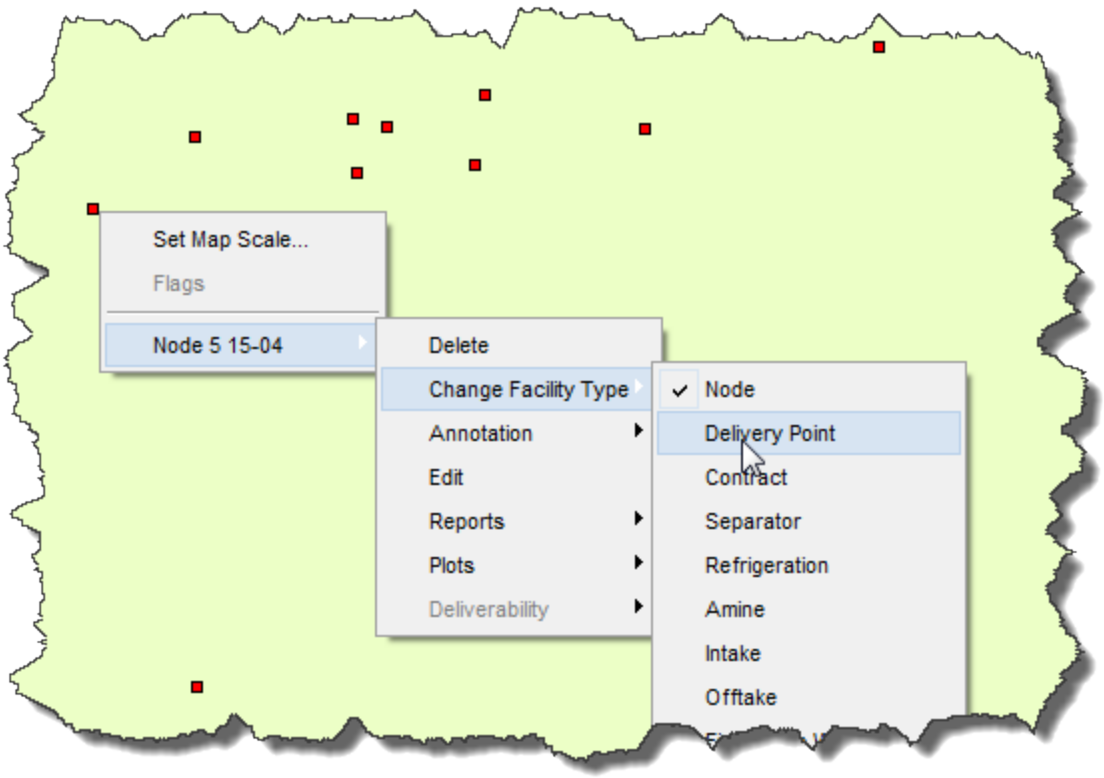
9. (Optional) To view removed points, click the **Show removed nodes and links** checkbox. Removed points are displayed in a light gray color. To add them back, reselect the points, and click the () icon.

10. Click **Import**.

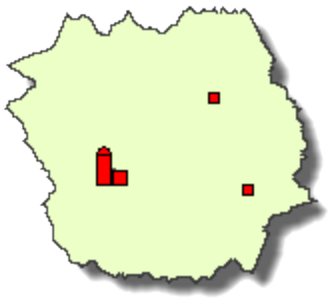
Converting nodes to facilities

To convert nodes to facilities:

Right-click the node, select **Change Facility Type**, and select the facility type to convert to.



For example, if Delivery Point is selected, the node changes to a delivery point facility.



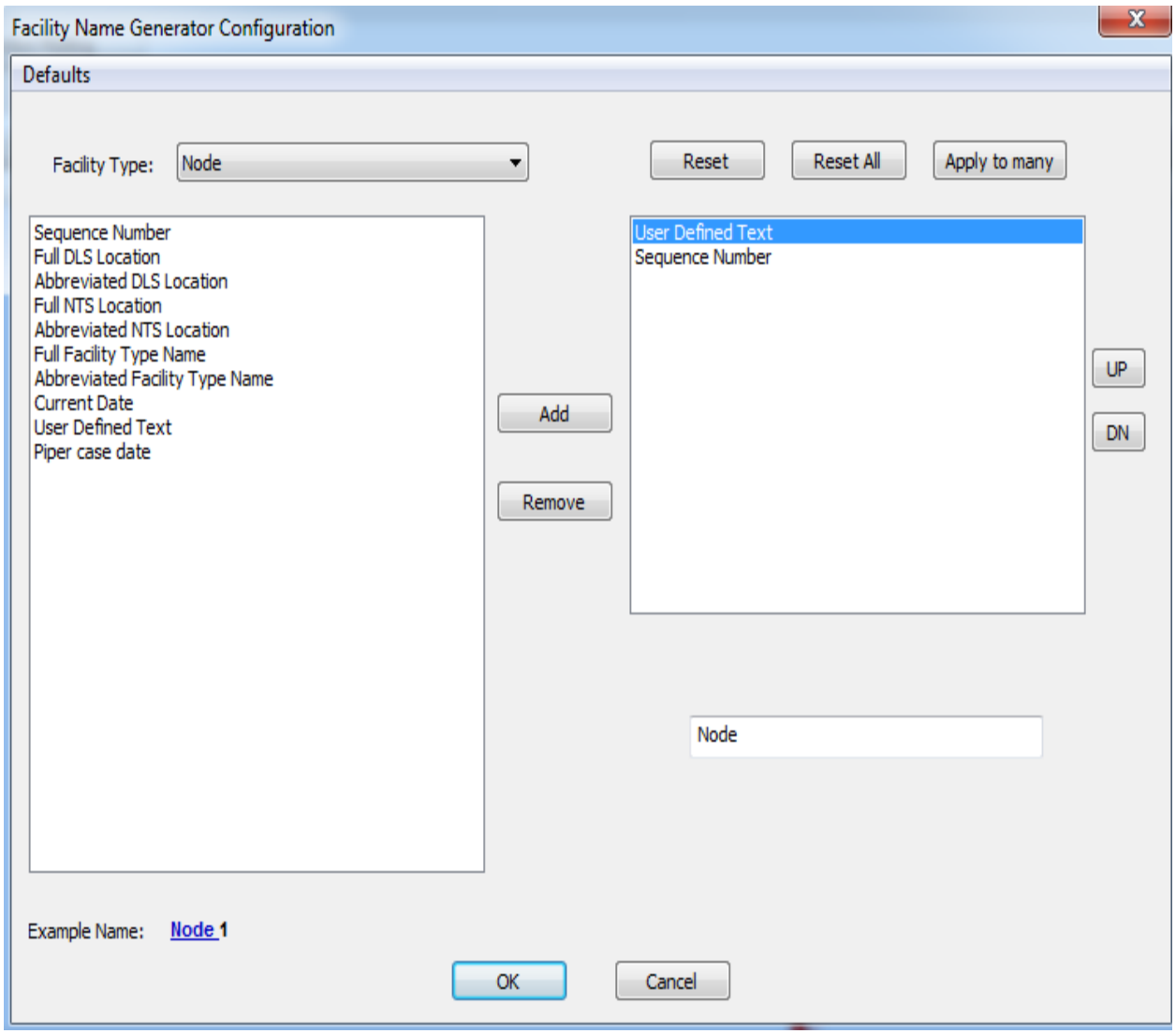
Using the name generator

Piper includes a name-generating tool that enables you to customize the names of nodes and facilities as they are created in the gathering system model.

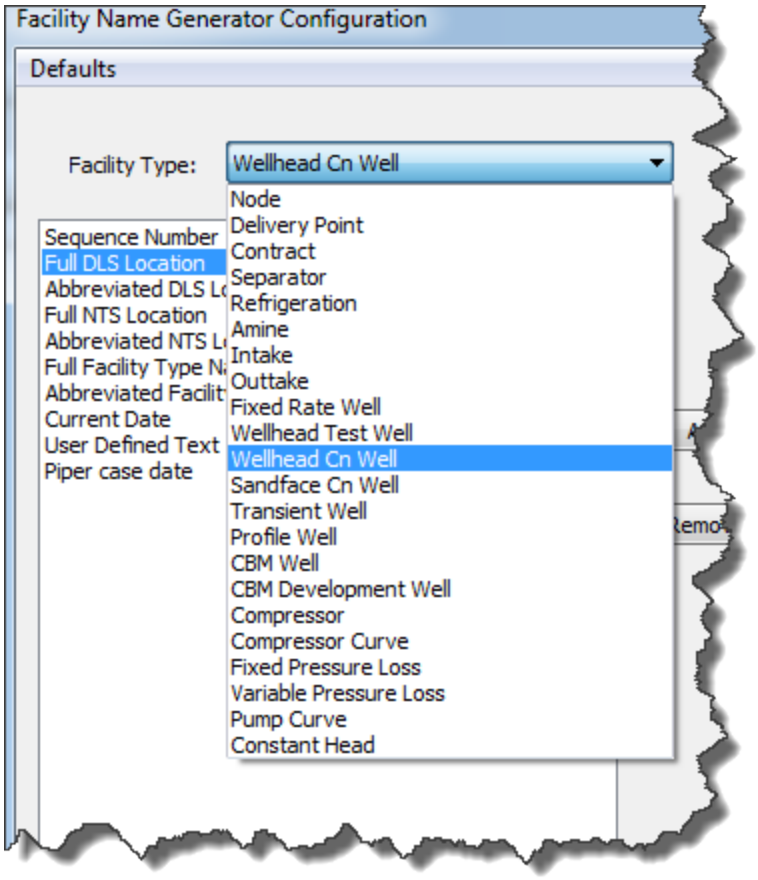
To use the name generator:

1. .Click the **Configure Name Generator** icon ( ) in the GIS design toolbar.

   The Facility Name Generator Configuration dialog box opens.



2. Select the **Facility Type** from the drop-down list.



3. Select your name elements from the left-side box and click **Add** to form the naming scheme for the facility type:

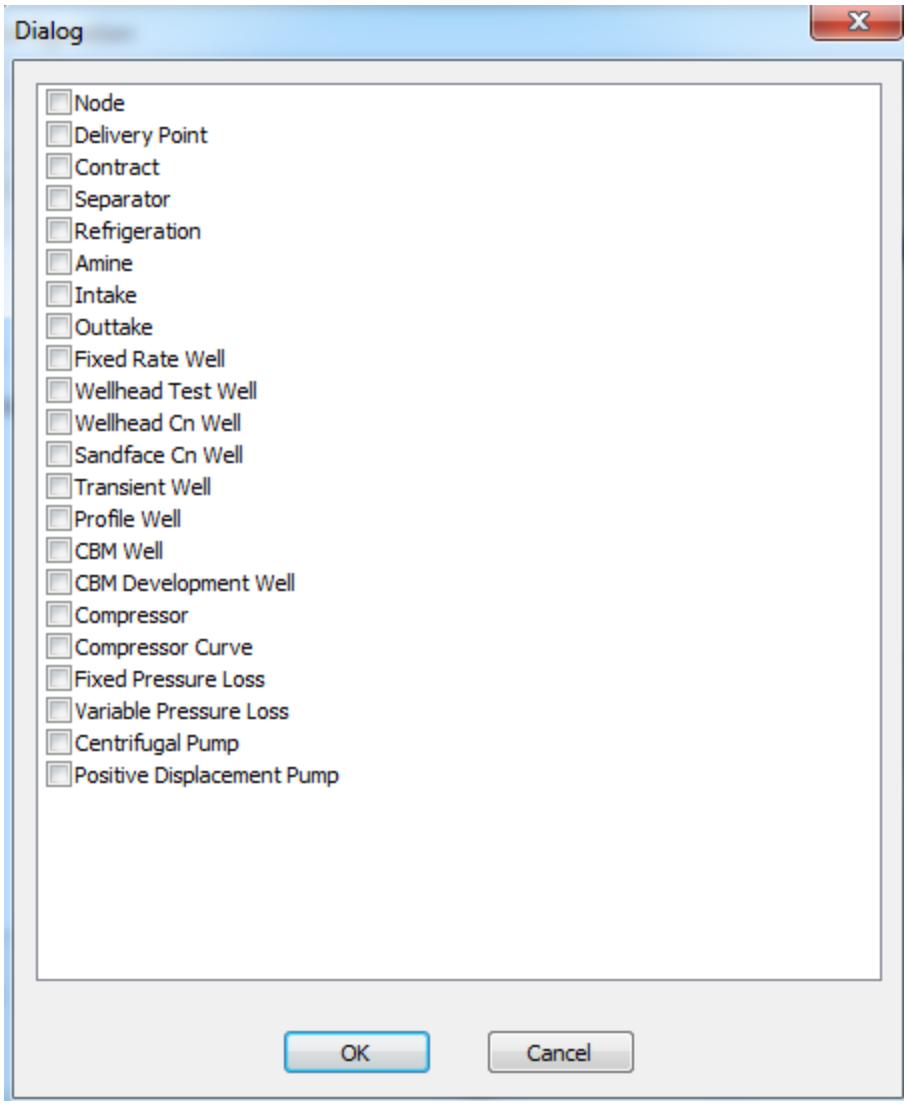
    - **Sequence Number** — specify your **Start** and **Increment** values.
    - **Full DLS Location** — when facilities or nodes are placed in a location covered by the Dominion Land Survey coordinate system, the facility name reflects that location.
    - **Abbreviated DLS Location** — only the ”LSD-Section” component of the DLS string is included.
    - **Full NTS Location** — when facilities or nodes are placed in a location covered by the National Topographical Survey coordinate system, the facility name reflects that location.
    - **Abbreviated NTS Location** — only the ”1/4 Unit - Unit -Block” component of the NTS string is included.
    - **Full Facility Type Name** — uses the facility name (e.g. Compressor, Fixed Rate Well, etc).

- **Abbreviated Facility Type Name** — uses an abbreviated facility name (e.g. Comp, Sep, Well, etc).
- **Current Date** — specifies the date when the facility was added as per the local time clock.
- **User Defined Text** — any text string can be added, including spaces to separate other text strings.
- **Piper Case Date** — specifies the current configuration date when the facility is being added.

Selected name elements are displayed in the right-side box, and an example is displayed at the bottom (providing a preview of the generated name).

4. (Optional) To apply the customized naming scheme to other facility types, click **Apply to many**.

   A dialog box opens with a list of facility types to select.



5. (Optional) Select the additional facility types and click **OK**.

   All selected facility types have the same naming convention applied.

6. Click **OK** again to apply the name selections, and close the Name Generator dialog box.

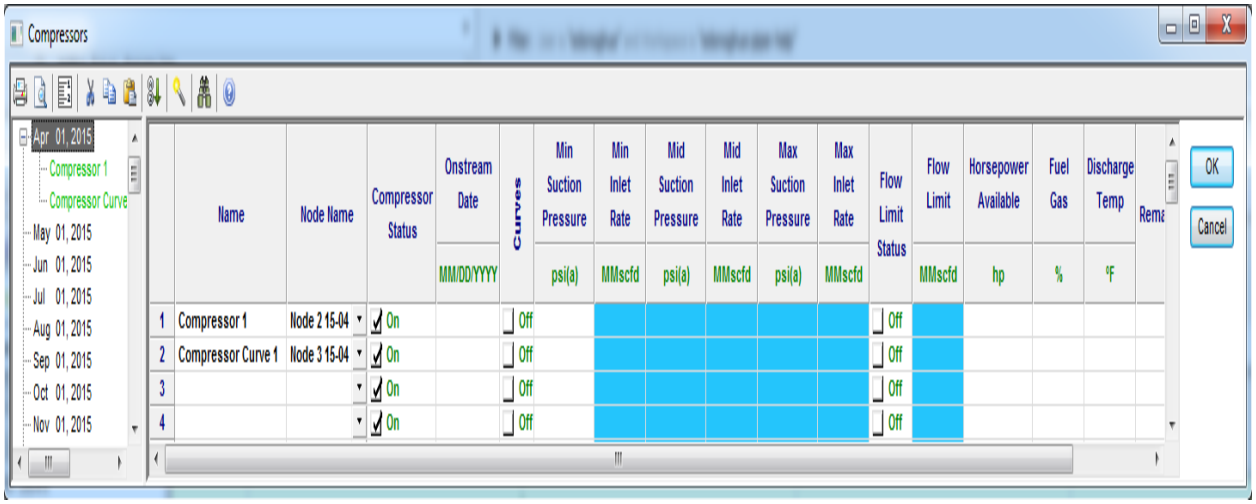
Using compressors

To use compressors:

1. Click the **Facilities** menu and select **Compressors**.

   Or, right-click the compressor on the map, select the compressor, then select **Edit**.

   The Compressors dialog box opens.



2. Set the **Compressor Status** by toggling the checkbox on or off. If the compressor status is **Off**, it is displayed in gray on the map ( ). If the compressor status is **On**, it is displayed in blue ( ).

3. By default, the compressor Onstream Date is blank. If there is no Onstream Date, the compressor is On (i.e., operational) by default. If you want the compressor to come online at a later date, enter the **Onstream Date**. A compressor is not operational until it reaches its onstream date. It is displayed in gray on the map if it is not operational ( ). If a compressor does not have an onstream date, or has reached its onstream date, it is displayed in blue ( ).

4. If the compressor is modeled with no compressor curves (**Curves** is not selected), and no horsepower limit (**Horsepower Available** is not set), enter the **Min Suction Pressure**. Proceed to step 9.

   Note: A minimum suction pressure is often used for wellhead compression, or in fixed-rate models to force the suction pressure. However, if you are producing in a looped gathering system and compressors are competing for gas volumes and / or are operating

at different suction pressures, we recommend entering compressor capacity curves. Compressor capacity curves account for the physical operating conditions of the unit and gathering system.

5. If the compressor is modeled with no compressor curves (**Curves** is not selected), but with a horsepower limit (**Horsepower Available** is set), enter the **Min Suction Pressure** and the **Horsepower Available**. Proceed to step 8.

6. If the compressor is modeled with compressor curves, and it is not limited by the power constraints of its driver, **Curves** is selected. Enter the following:

   - **Min Suction Pressure**
   - **Min Inlet Rate**
   - **Max Suction Pressure**
   - **Max Inlet Rate**

   Proceed to step 8.

   For more information on compressor capacity curves, see compressors.

7. If the compressor is modeled with compressor curves, and it is limited by the power constraints of its driver, also enter the following:

   - **Mid Suction Pressure**
   - **Mid Inlet Rate**

8. (Optional) If the compression facility is subject to contract limitations, or you need to choke all wells upstream of the compressor, set the **Flow Limit Status** to On and enter the **Flow Limit**.

   Note: If you are using Fixed Rate or Profile wells in your model, the summation of gas must not exceed the flow limit or maximum compressor capacity.

9. (Optional) In order to remove fuel gas on compressor discharge, enter **Fuel Gas** as a percentage of the inlet rate.

10. (Optional) Enter the discharge temperature of fluid exiting the compressor.

11. Click **OK**.

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Using separators

When using separators, you can recombine separator outlets to model your downstream gathering system, edit separator parameters, and change the separator's orientation on the map.

Setting the recombine state

To set the recombine state:

- Right-click the separator on the map, select **Recombine**, and click one of the options: none, all, gas oil, gas water, and liquid.
- Or, click the **Facilities** menu; select **Separators**; then select a Recombine state from the drop-down list in the **Recombine** column.

For more information on recombine states, see separator outlet options.

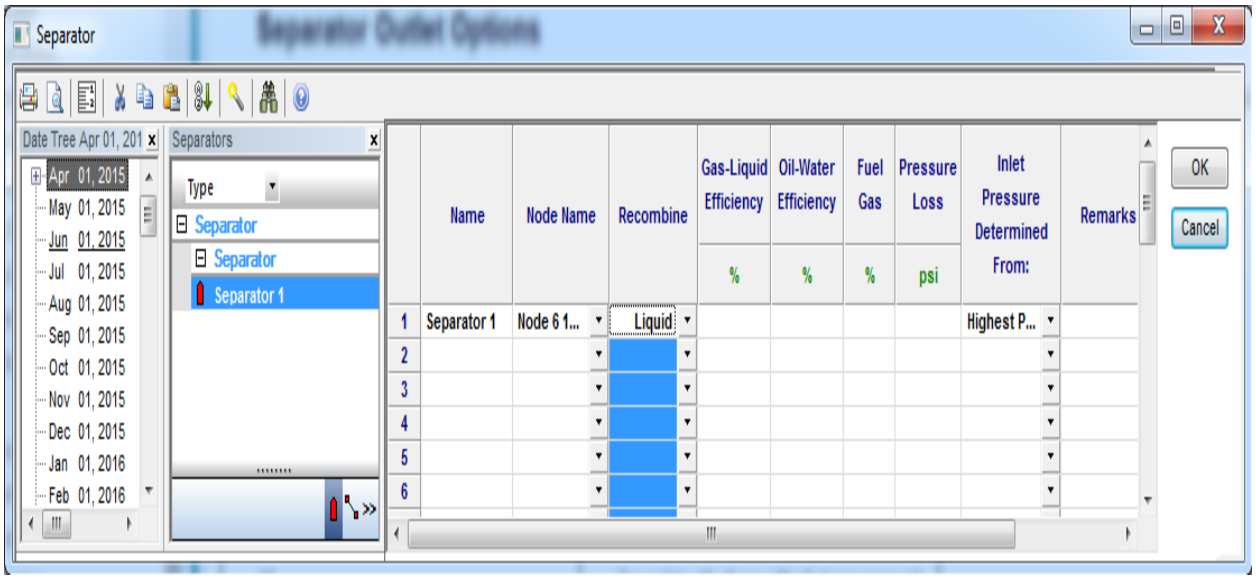
Editing separator parameters

To edit separator parameters:

1. Click the **Facilities** menu, and select **Separators**.

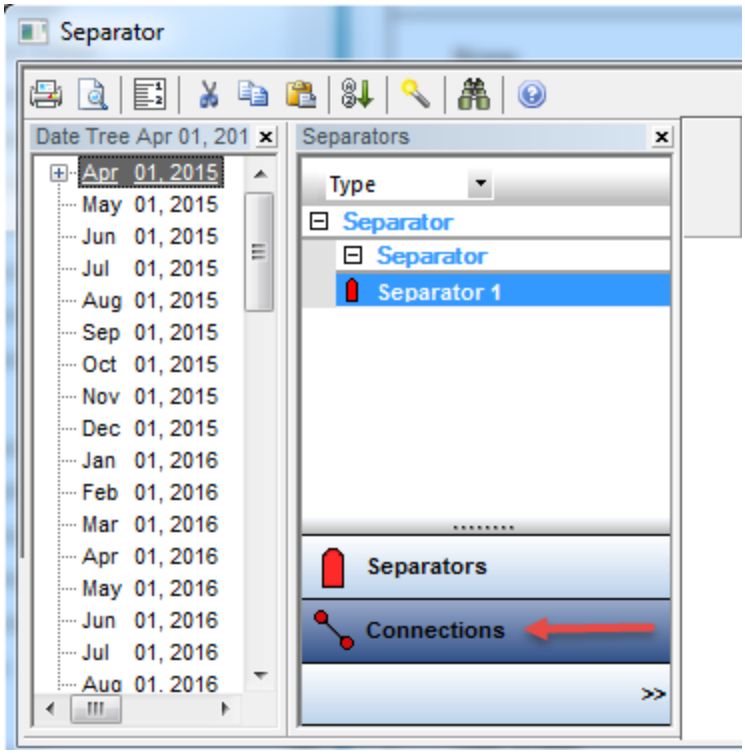
   Or, right-click the separator on the map, select the separator, and click **Edit**.

   The Separator dialog box opens.



2. Set the **Recombine** state from the drop-down list.

3. (Optional) Set the **Gas-Liquid** and **Oil-Water Efficiencies** based on the operational performance of the separator.
4. (Optional) Enter the **Fuel Gas** extracted.
5. (Optional) Enter the **Pressure Loss**.
6. Set the source for your **Inlet Pressure** from the drop-down list.
7. (Optional) Click the **Connections** button to view the separator's links.



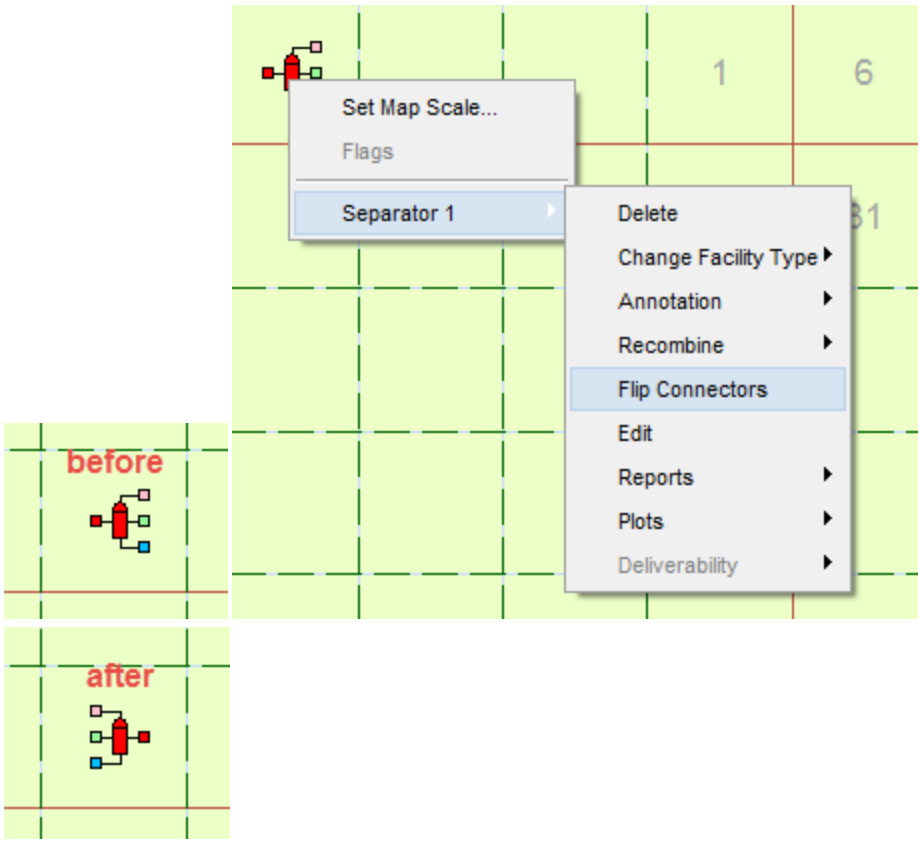
8. Click **OK**.

Changing the orientation of separators

To make sure the links to your separator do not overlap, you can change the orientation of a separator:

Right-click the separator on the map, and select **Flip Connectors**.

The orientation of the separator inlet and outlets is rotated 180°.


1
6
31
Set Map Scale...
Flags
Separator 1
Delete
Change Facility Type
Annotation
Recombine
Flip Connectors
Edit
Reports
Plots
Deliverability
before
after

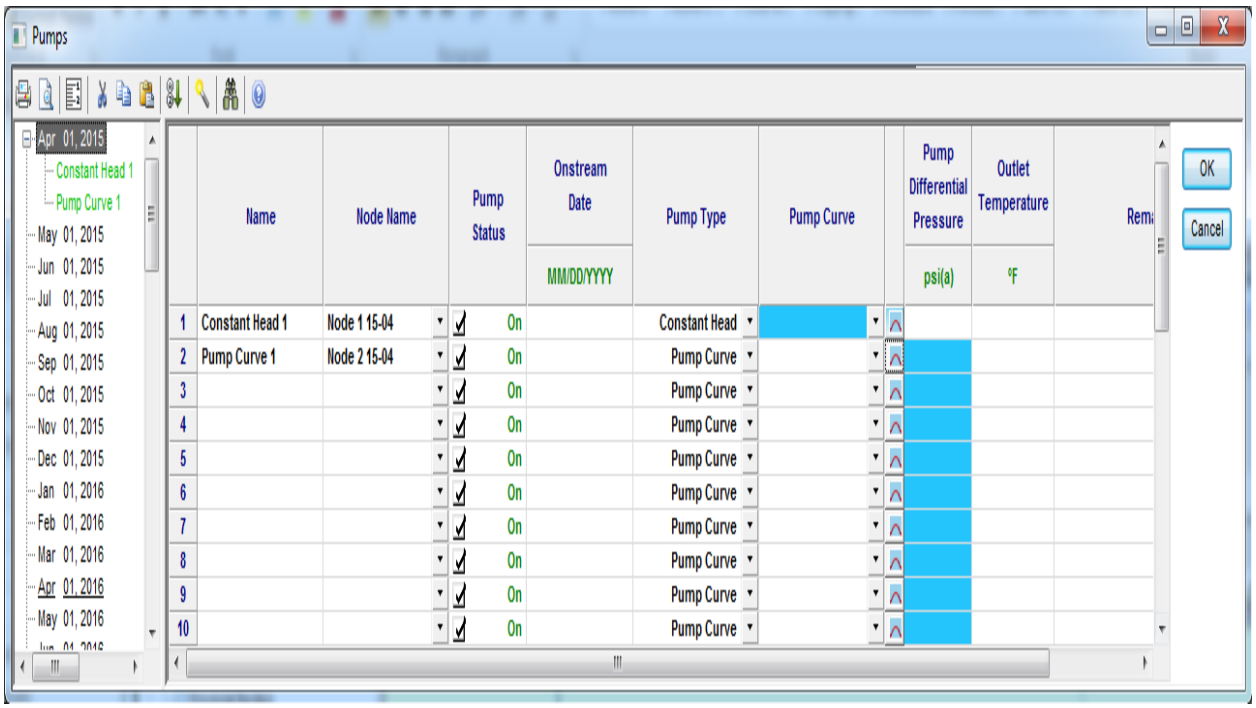
Using pumps

To use pumps:

1. Click the **Facilities** menu and select **Pumps**.

   Or, right-click the pump on the map, select the pump, then select **Edit**.

   The Pumps dialog box opens.



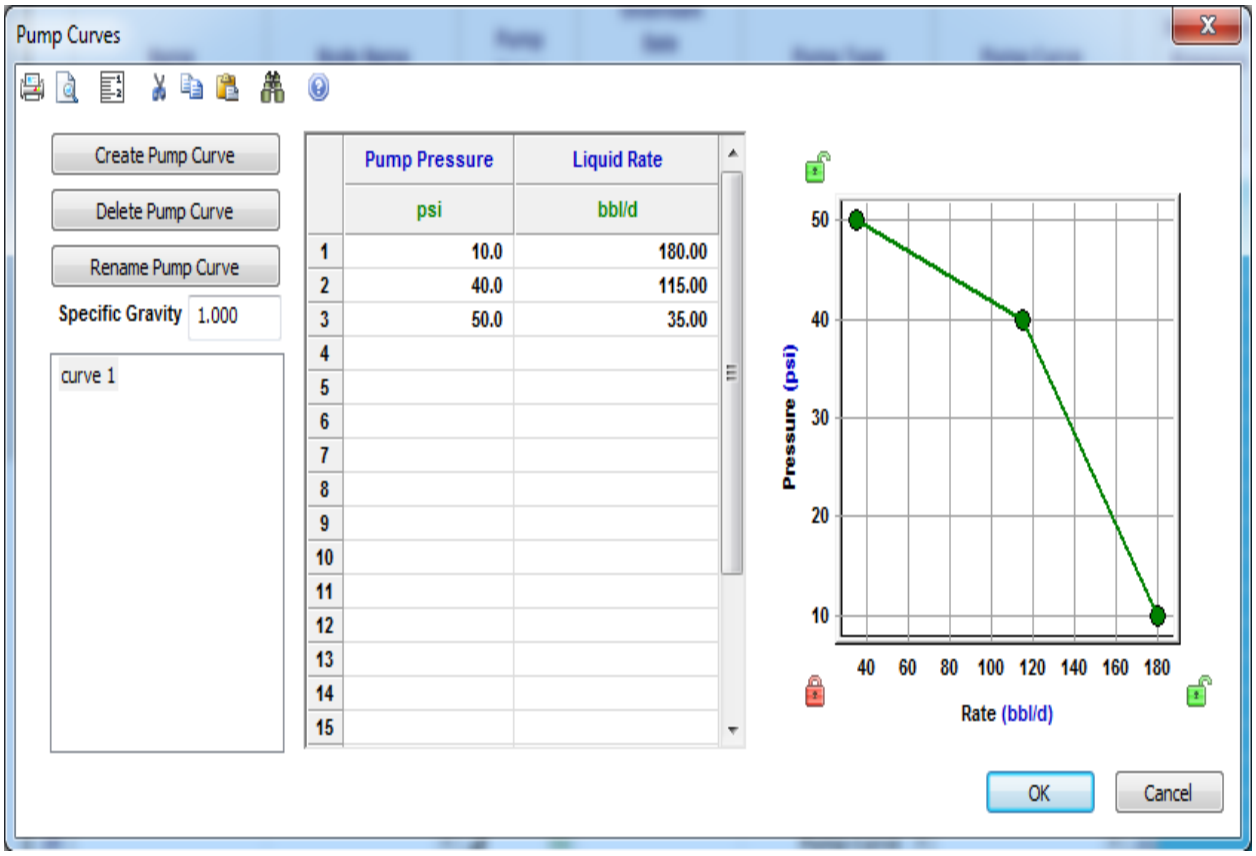
2. Set the **Pump Status** by toggling the checkbox on or off. If the pump status is **Off**, the pump is displayed in gray on the map. If the pump status is **On**, it is displayed in green.

3. By default, the pump Onstream Date is blank. If there is no Onstream Date, the pump is On by default. If you want the pump to come online at a later date, enter the **Onstream Date**. A pump is not operational until it reaches its onstream date. It is displayed in gray on the map if it is not operational. If a pump has reached its onstream date, it is displayed in green.

4. Enter your pump data:

   - for constant head pumps, enter the **Pump Differential Pressure**
   - for pump curves, click the pump curve icon () to enter the capacity curve data

   The Pump Curves dialog box opens.



a. Click **Create Pump Curve**, enter a name for the pump curve and click **OK**. The **Pump Pressure** and **Liquid Rate** grid / table is enabled.

b. Enter the data for the capacity curve. The pump data is graphically displayed in the plot. Note that as the pressure increases, the rate must decrease, otherwise an error message is displayed.

c. (Optional) Enter the **Specific Gravity** for the pump's fluid.

d. Click **OK**.

By default, the name of the most-recently-created pump curve is displayed in the Pump Curve column of the Pumps dialog box. If you have several different pump curves, make sure the appropriate pump curve is selected for each pump. Note that pump curves can be attached to more than one pump.

5. Click **OK**.

See Pumps for more information.

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Working with links

These topics relate to working with links:

- adding links
- optimizing loop links
- splitting links
- editing link diameters
- reconnecting links

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Adding Links

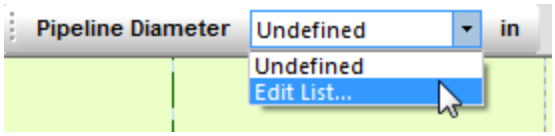
You can add links in Piper by:

- editing the map
- adding links from a shapefile
- modifying loop links

Editing the map

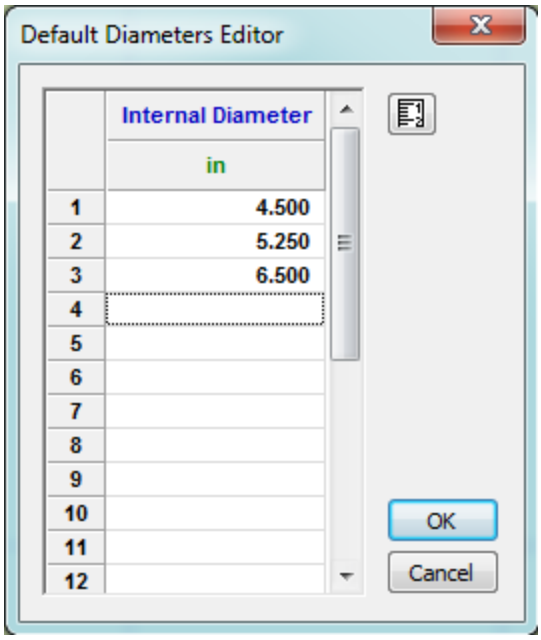
To edit the map:

1. Enter the model's pipeline diameters. Click the **Pipeline Diameter** drop-down list from the Pipeline Diameter toolbar, and select **Edit List**.



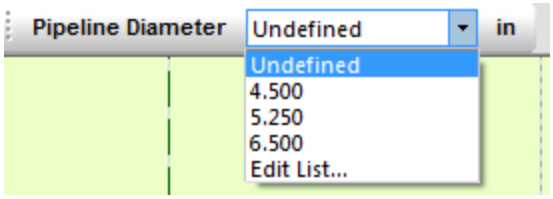
The Default Diameters Editor opens. Note that Undefined is used to create pipelines without a diameter for cases that do not require pressure losses, or if the diameter is not known.

2. Enter pipeline diameter values. Click **OK**.



The Pipeline Diameter drop-down list contains the values you entered.

3. Select a pipeline diameter from the Pipeline Diameter drop-down list.



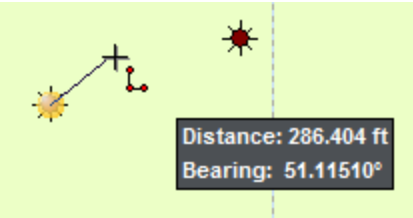
4. Click the link icon ( ) on the GIS toolbar to begin linking the gathering system.

   The mouse cursor changes to a link cursor ( ).

5. Move the mouse pointer over a facility until a highlight bubble appears ( ).

   The highlight bubble indicates the starting point of your link.

6. Click the facility and drag your cursor to the facility you want to connect to. Continue linking, until your gathering system is complete.



7. Right-click the map to stop linking.

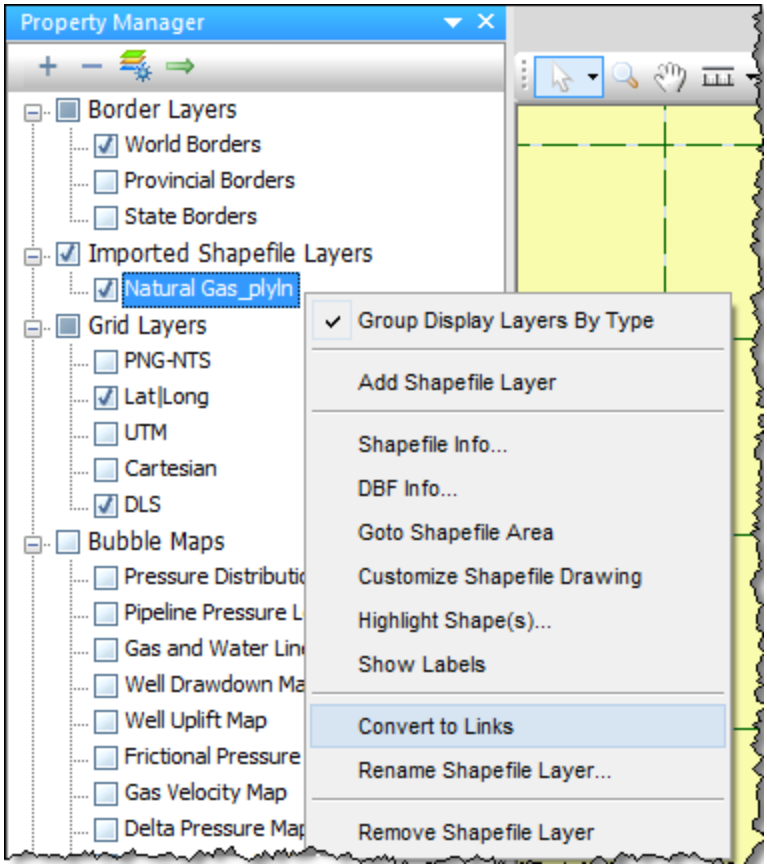
   Pipelines are color-coded based on their diameter. Note that you have to be connected to a delivery point to see your specified pipeline colors, otherwise the links are displayed in black.

   Pipeline diameters affect pressure losses. For more information, see pressure loss calculations.

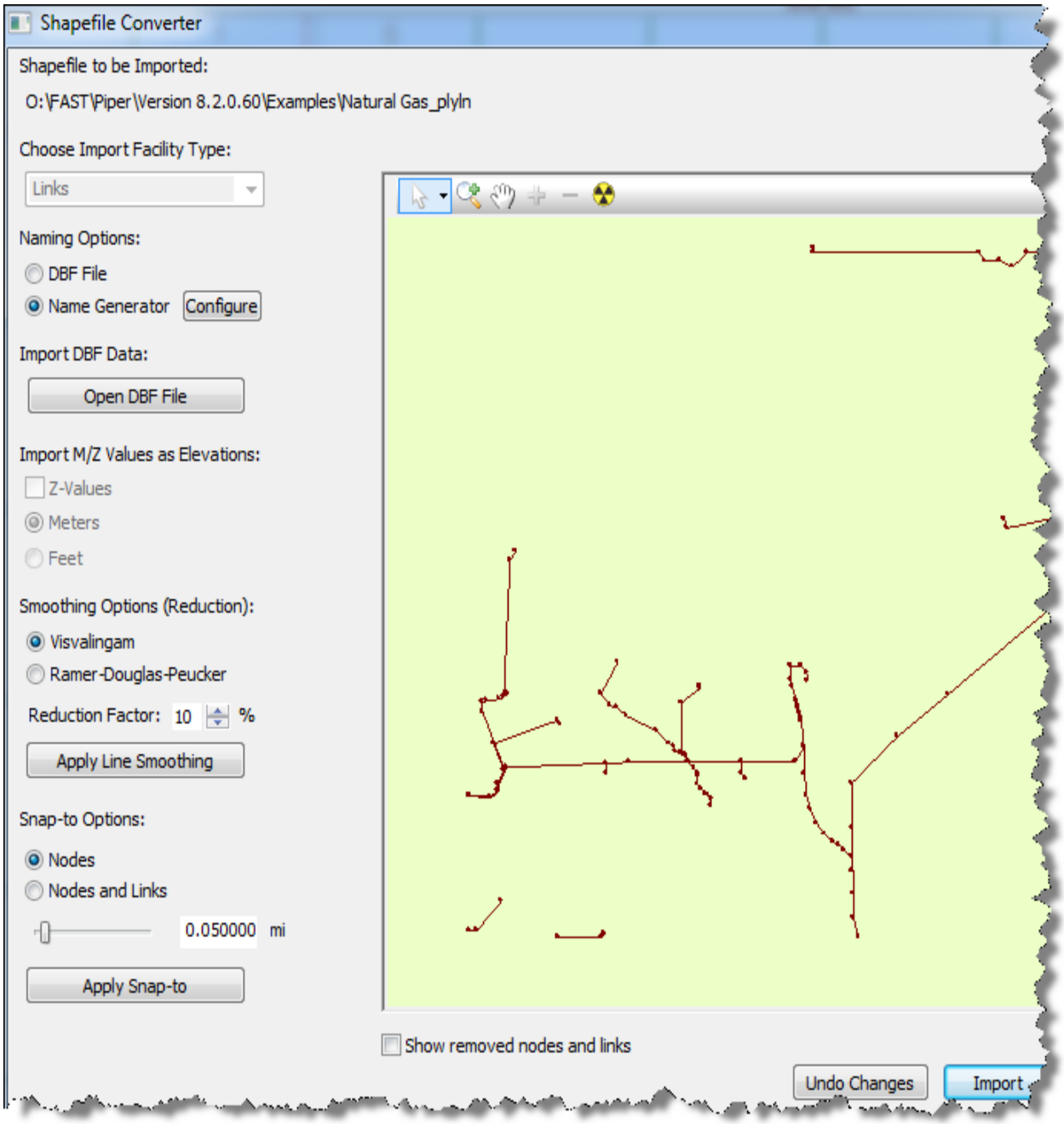
Adding links from a shapefile

To add links from a shapefile:

1. Import a shapefile.
2. Right-click your imported shapefile layer in the Property Manager, and select **Convert to Links**.

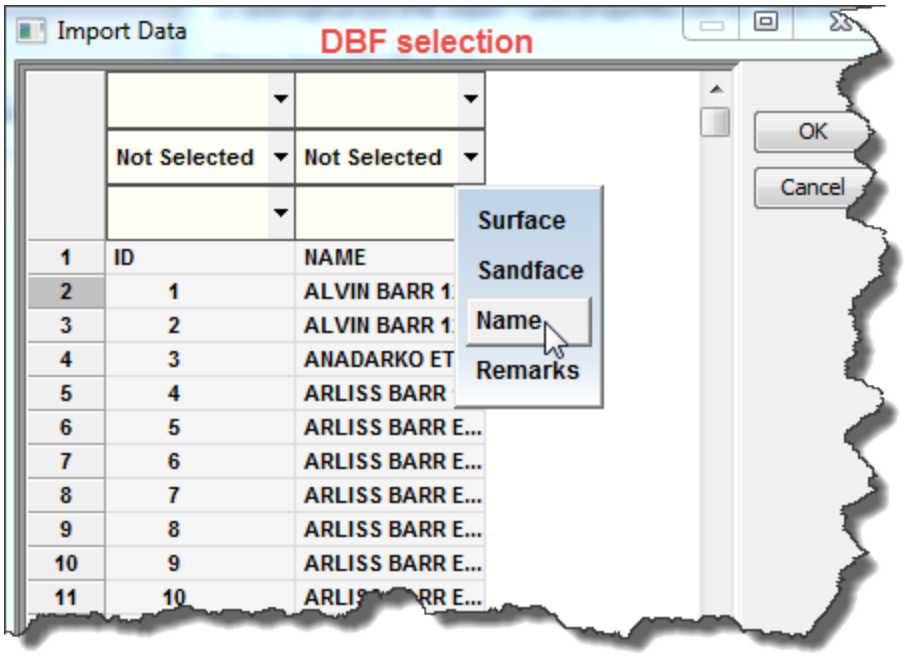


The Shapefile Converter dialog box opens. Note that the Choose Import Facility Type is set to Links, and cannot be changed.

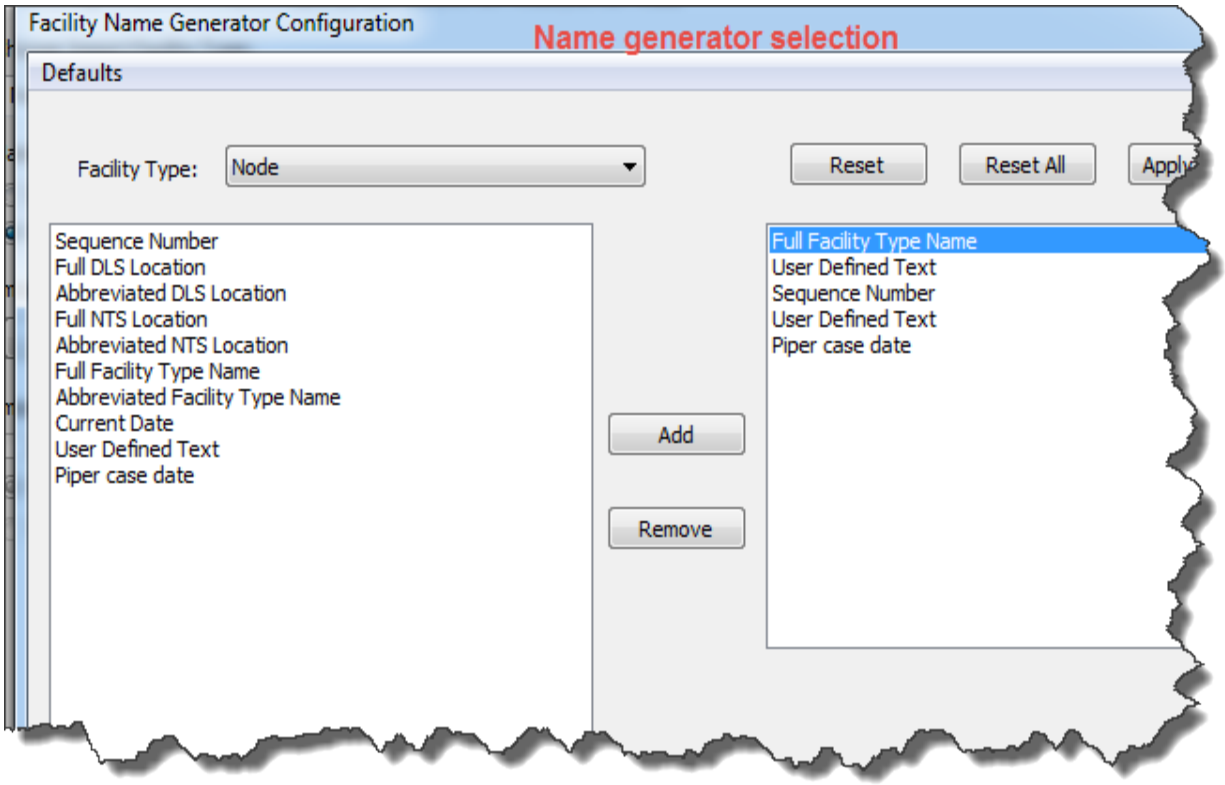


3. Assign a unique name to your links by selecting a naming option:

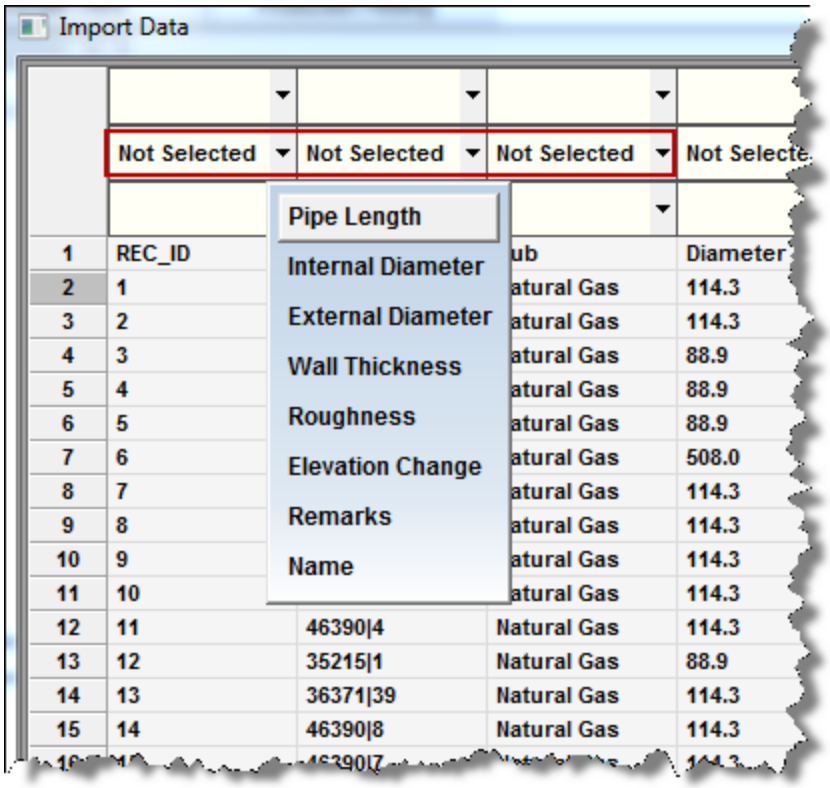
   - select **DBF File** and click the **Open DBF File** button to view the shapefile attribute data. Select a column to apply your name attribute to. For example, if column 2 is selected, your names are ALVIN BARR 1, ALVIN BARR 2 etc.



- or, select **Name Generator** (default setting) and click **Configure** to choose from a list of naming options.



4. (Optional) Click **Open DBF File** to import pipeline specifications from the link attribute DBF data. Select the data for import from the drop-down lists in the columns of the table.



5. (Optional) If elevation data is contained as a z-component in the shapefile, the **Import M / Z Values as Elevations** checkbox is enabled. Click the checkbox to import elevation data.

   Note: If you want to reduce your import time, we recommend that you follow the optional steps below.

6. (Optional) To make sure that the imported links form a single continuous link see Snap-to.

7. (Optional) To reduce the number of nodes imported, under **Smoothing Options (Reduction)**:

   - select the smoothing algorithm to apply (**Visvalingam** or **Ramer-Douglas-Peucker**)
   - select the **Reduction Factor**
   - click **Apply Line Smoothing**

   To view the removed nodes, select the **Show removed nodes and links** checkbox. You may need to zoom in to view the removed points, which are displayed in gray.

Note: If you want to revert your changes, click **Undo Changes**. This retains your import selections, and reverts your smoothing, and snap-to selections.

8. Click **Import**.

Modifying loop link selection

A loop link designates a location where flow rate is being calculated. For example, when flow can go multiple ways, a loop link defines the key pipe link used to calculate how the total rate should be split between those multiple paths. Loop links are required whenever flow is split, such as for parallel flow paths and when multiple delivery points exist.

The default setting is for Piper to automatically select loop links for each flow split in the gathering system model. We recommend you use this default when building your model. You can also manually select loop links. However, manually selecting loop links should be done only if required, and after your gathering system model is built.

Important: If you manually select loop links, you can only designate one link in a flow split to be a loop link.

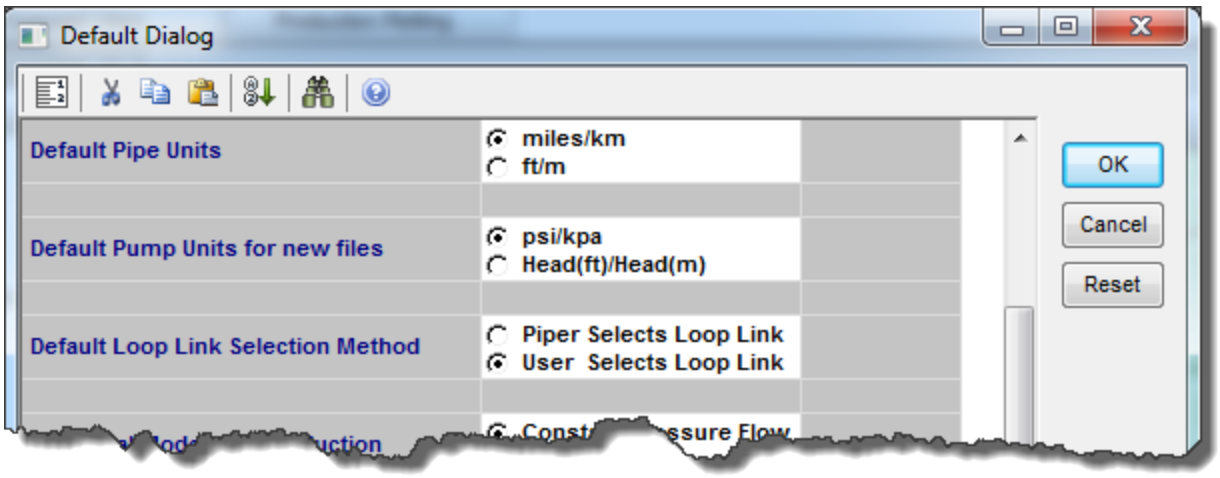
Manually selecting loop links

To manually select loop links:

1. Click the **Properties** menu and select **Defaults**.

   The Default dialog box opens.

2. Select **User Selects Loop Link** for the Default Loop Link Selection Method.



3. Click **OK**.

   The Looped column is enabled in the Gathering System dialog box.

4. (Optional) Click Ctrl+L to review the current loop assignment on the map.

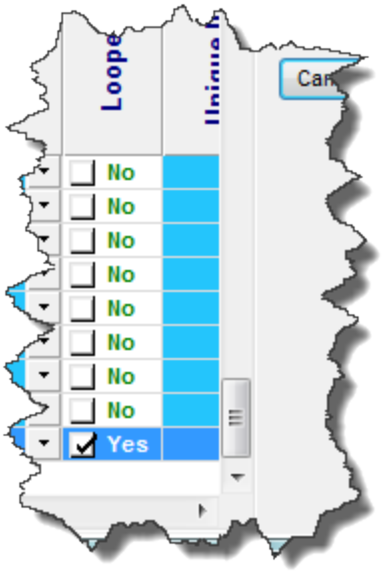
5. On the map, find the loop (i.e., the flow split) where you want to select a loop link.

   If a loop link has already been selected for that loop, make a note of its start and end nodes.

6. Right-click the link you want to designate as a loop link and select **Edit**. To determine optimal loop link selection, see Optimizing loop links.

   The Gathering System dialog box opens with the selected link highlighted.

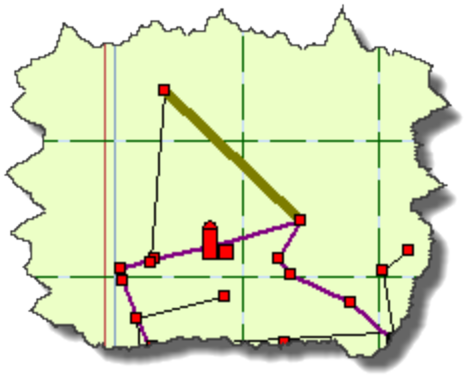
7. Toggle the **Looped** checkbox to **Yes**.



Important: If you noted an existing loop link in step 5, find that link in the Gathering System editor, and toggle its **Looped** checkbox to **No**.

8. (Optional) Enter a remark in the Remarks column.

9. Click **OK**.



Missing loop link

If a message is displayed in the status window indicating that a loop was created without a designated loop link, then you must add a loop link in your gathering system model. Until you specify a loop link, Piper disables one of the flow paths for that loop. Disabled loop links are displayed in black on the map.

To correct missing loop links:

1. Review the loop and select a link to designate as a loop link. See manually selecting loop links above.
2. For the disabled link, toggle the **Disable Link** checkbox in the Gathering System dialog box to **Off** so that the link is now enabled.

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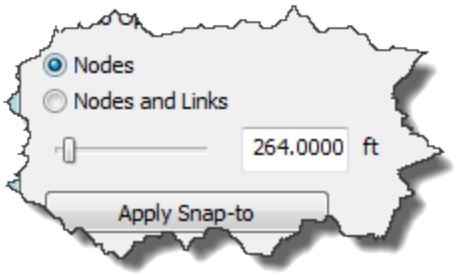
Snap-to

The Snap-to feature is used when adding links from a shapefile. It connects nodes that are close to, or on top of other nodes, so that a single continuous set of links imports into Piper.

Auto snap-to

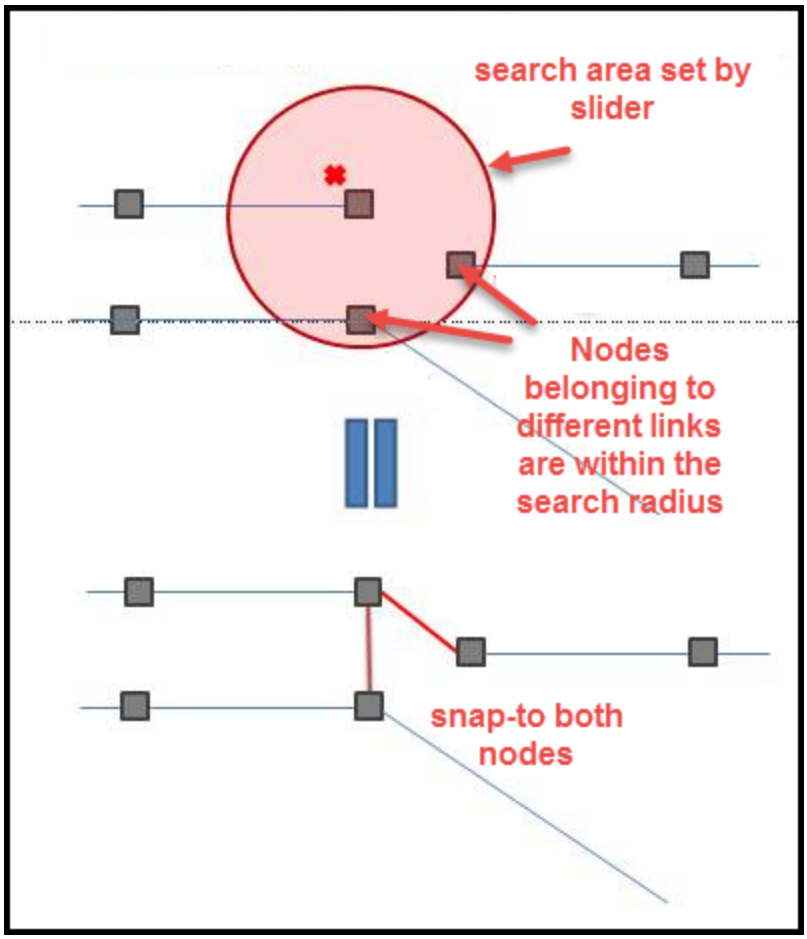
To automatically snap to:

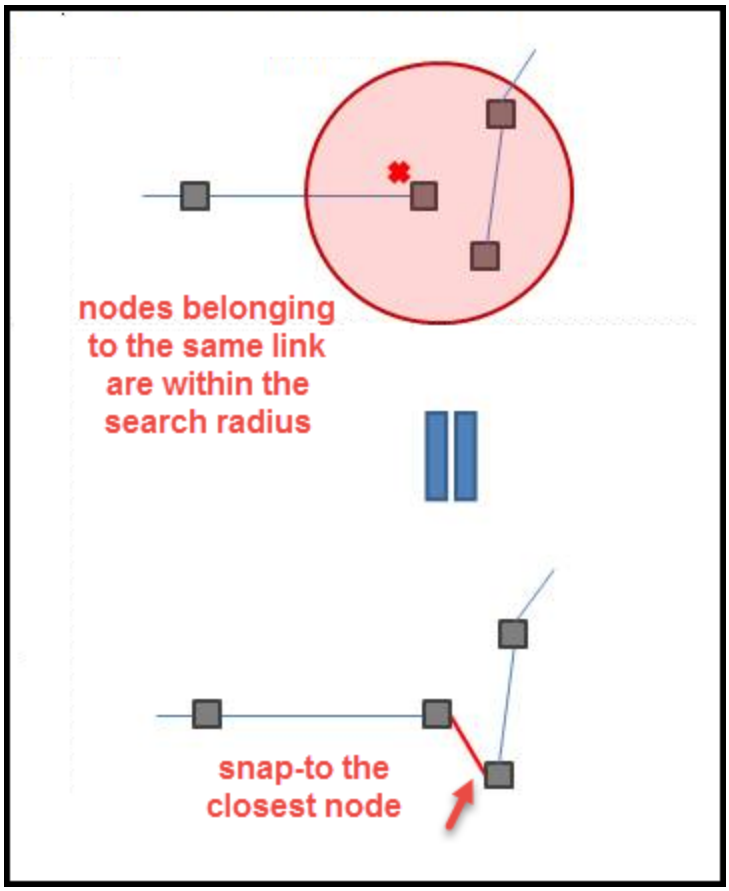
1. In the Shapefile Converter dialog box, set the search radius:
    - move the slider right or left to increase or decrease the search radius
    - or, enter the search radius manually in the edit box



2. In **Snap-to Options**:
    - select **Nodes** to automatically snap-to nodes

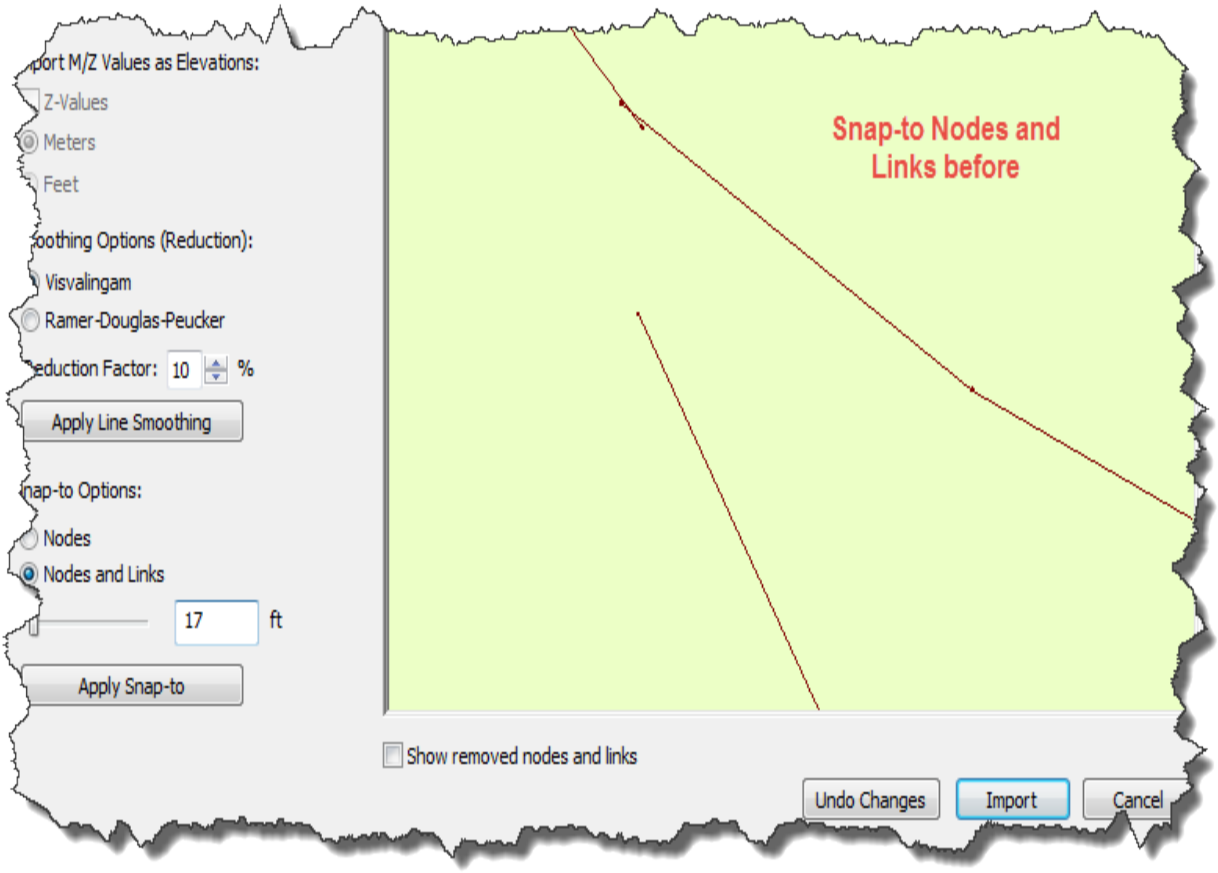
Snap-to functionality is illustrated below.

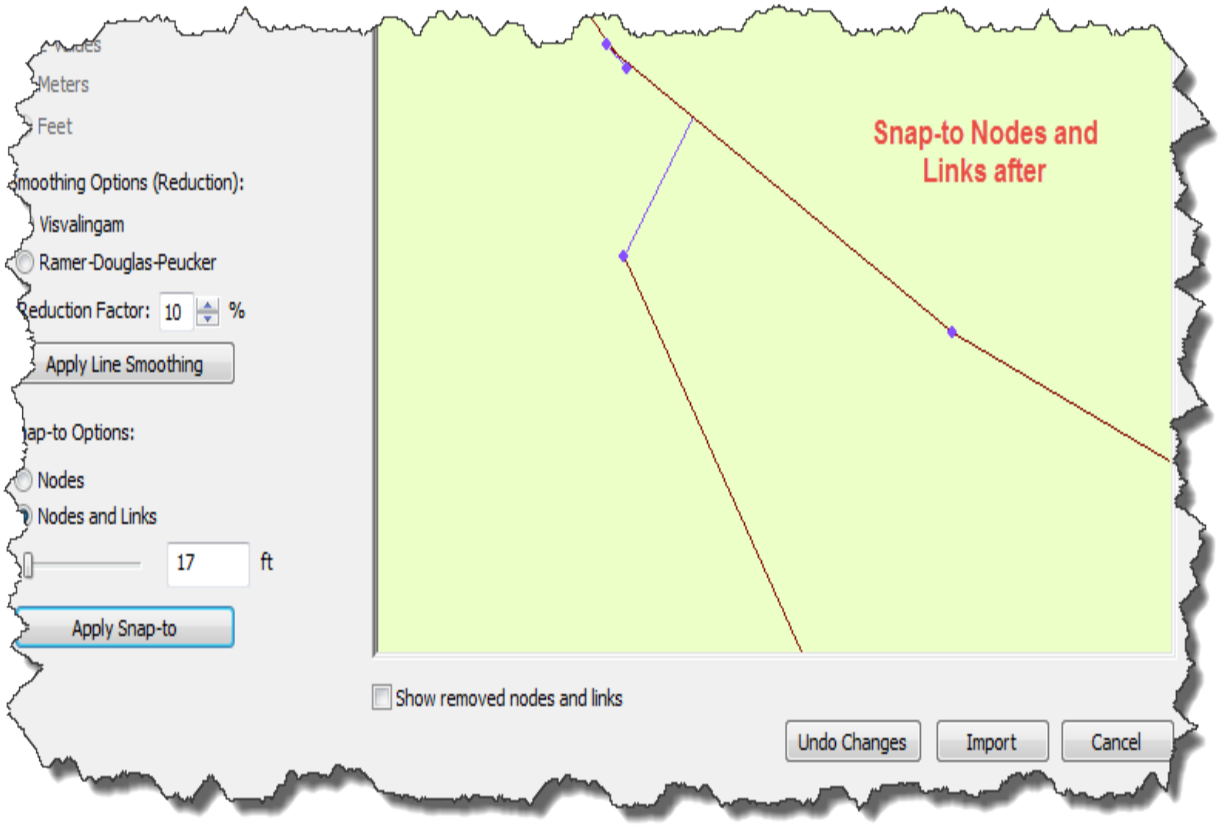

search area set by slider
Nodes belonging to different links are within the search radius
snap-to both nodes



- or, select **Nodes and Links** to automatically snap-to nodes and links

The before and after screenshots below illustrate snap-to nodes and links when a link is within the search radius.


port M/Z Values as Elevations:
Z-Values
Meters
Feet
oothing Options (Reduction):
Visvalingam
Ramer-Douglas-Peucker
eduction Factor: 10 %
Apply Line Smoothing
nap-to Options:
Nodes
Nodes and Links
17 ft
Apply Snap-to
Snap-to Nodes and Links before
Show removed nodes and links
Undo Changes
Import
Cancel



Snap-to Nodes and Links snaps to the shortest perpendicular distance of the adjacent link, even if there is no node at the snap-to point.

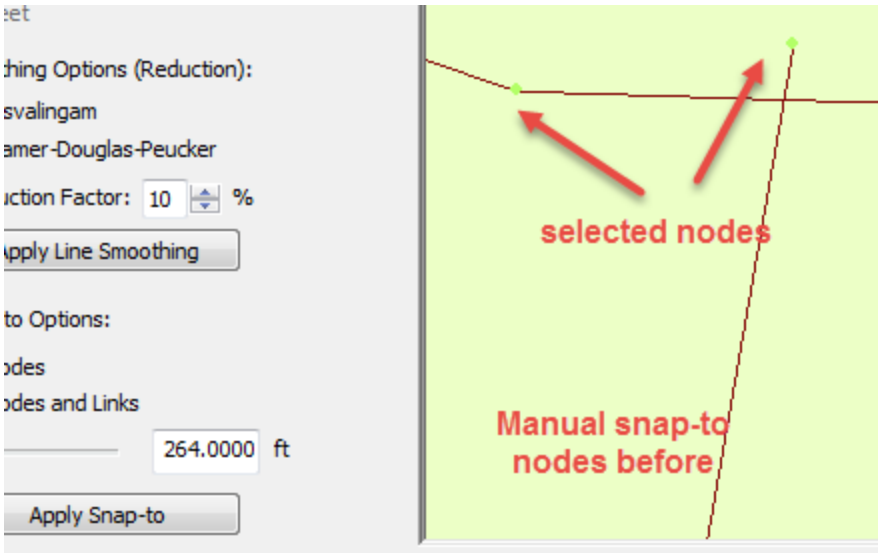
3. Click **Apply Snap-to**.

   All snap-to locations are displayed in purple on the map.

Manual snap-to

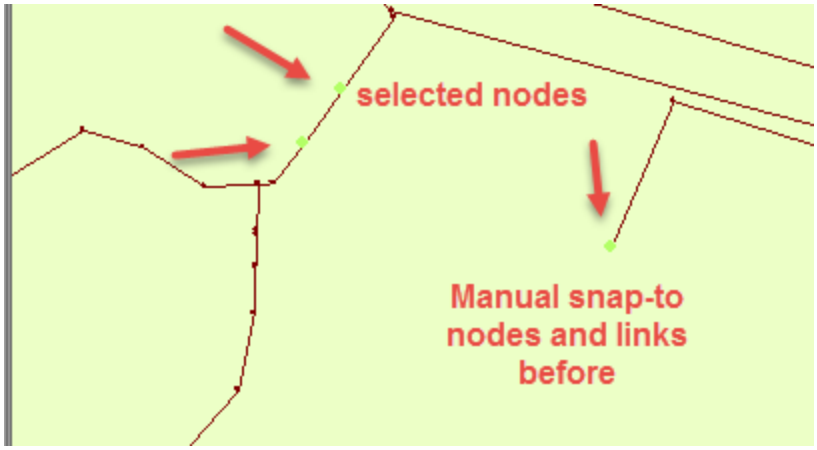
To manually snap to nodes, or snap to nodes and links:

1. On the map, select two nodes to snap together.



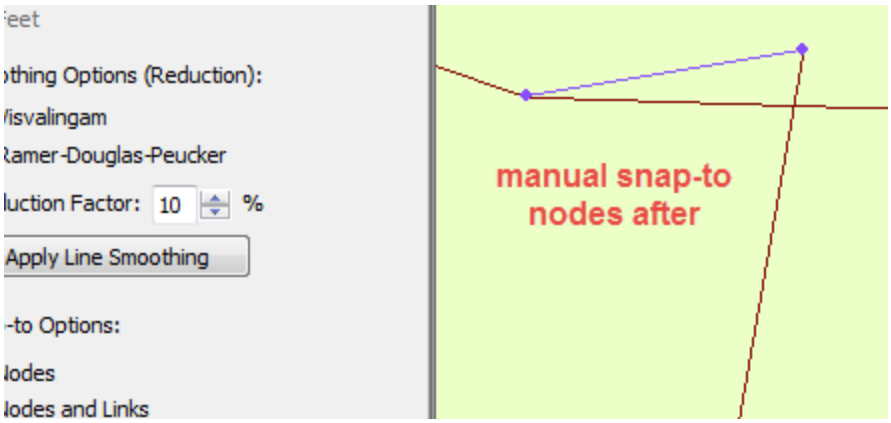
Or, to manually snap-to links, select three nodes to snap-to.

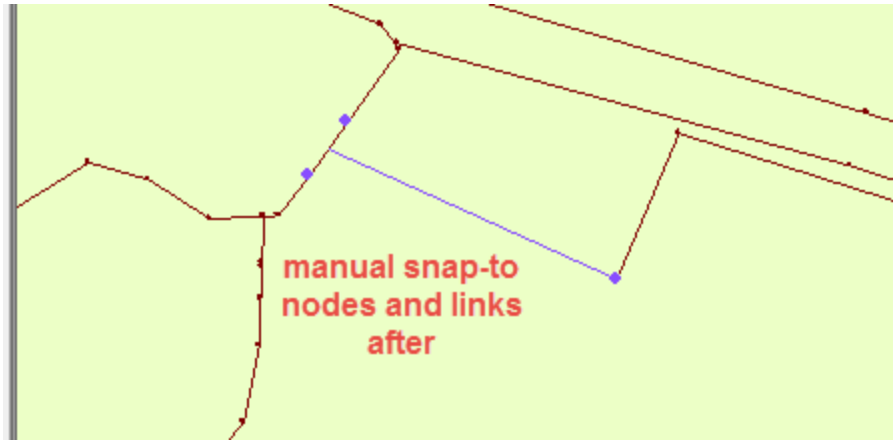
Note: When manually snapping to links, two of the selected nodes must belong to the same link.



Note: The search radius is not used in manual snap-to nodes, or manual snap-to nodes and links.

2. Right-click and select **Snap-to (if permitted)**.





Snap-to Nodes and Links snaps to the shortest perpendicular distance of an adjacent link, even if there is no node at the snap-to point.

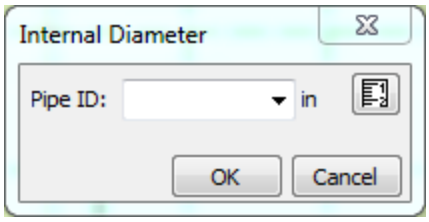
All snap-to locations are displayed in purple on the map.

Editing link diameters

Link diameters can be edited individually, or as a group selection.

1. Select your links (for information on selection, see selection pointer):
   - for an individual link, right-click the link and select **Edit Diameter**
   - for a selected group of links, right-click and select **Edit Selected Diameters**

   The Internal Diameter dialog box opens.



2. Select a Pipe ID from the drop-down list, or if a Pipe ID is not in the list, enter it manually.

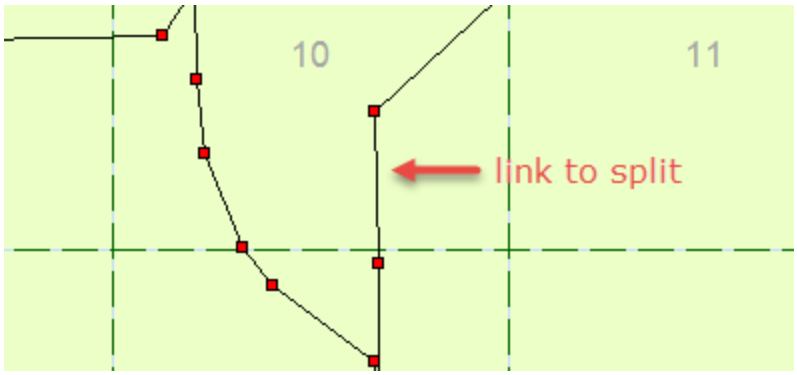
   Manually entered Pipe IDs are added to the Pipeline Diameter drop-down list in the Pipeline Diameter toolbar.

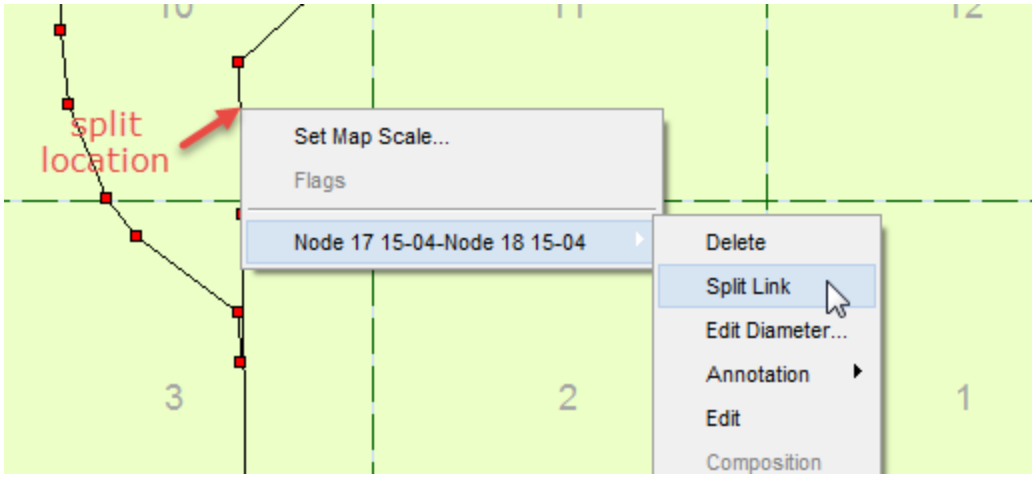
Splitting links

Splitting a link creates two links in the Gathering System dialog box, and one new node in the GIS Position dialog box. When a link is split, the map distance of each new link is based upon where the split occurs. The pipe length, and elevation change for the two new links are recalculated based on the ratio of each new link's distance to the original link's map distance. In the Gathering System dialog box, the following attributes for the two new links are the same as the original link: inner diameter (ID), Bearing, Roughness, and Correlation Adjustment.

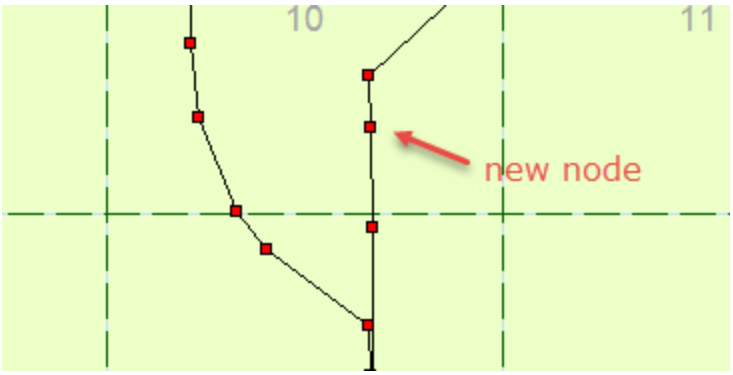
To split a link:

Right-click the link at the location where the split is to occur and select **Split Link**





The link is split in two, and a new node is added at the selected location.


10
11
new node

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Optimizing loop links

If a forecast is not converging quickly, it may be the result of a designated loop link in a non-ideal location. The status window identifies loop links that are not converging.

To optimize loop links for convergence:

1. Make sure loops connect to wells or nodes. Do *not* connect to:
    -  delivery points
    -  compressors
    -  contracts
    -  refrigeration facilities
2. Make sure loop links are upstream of a compressor or contract.
3. Include at least two nodes between a loop line and the upstream side of a compressor.
4. Make sure the pressure loss in a loop link is not zero.
5. Select smaller diameter lines with longer lengths as loop links. (A loop link cannot be on a link where the pipe diameter that is undefined.)
6. Select links with little or no elevation change.
7. Make sure designated loop links are not beside each other, or that they share a common node.
8. Verify that you have no disabled links within a loop in your gathering system. See adding loop links for details.

If a loop link fails to meet the criteria above, you can manually designate another link as the loop link.

Reconnecting links

Links can be reattached to other parts of the model by using the Reconnect Links tool.

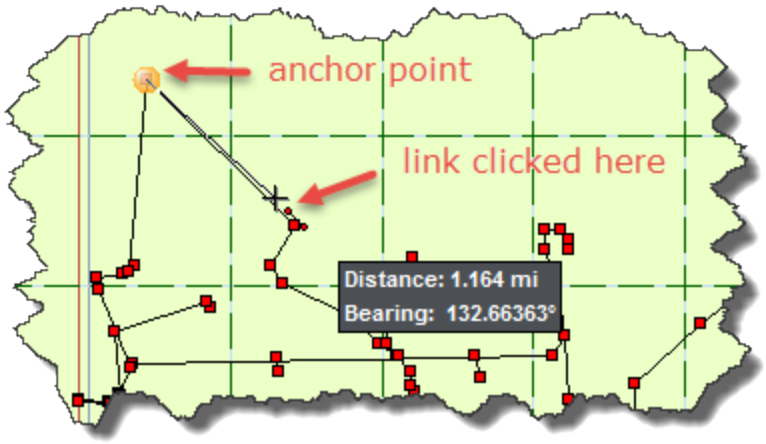
To reconnect links:

1. Click the **Reconnect Links** icon ( ).

   The cursor changes to this:

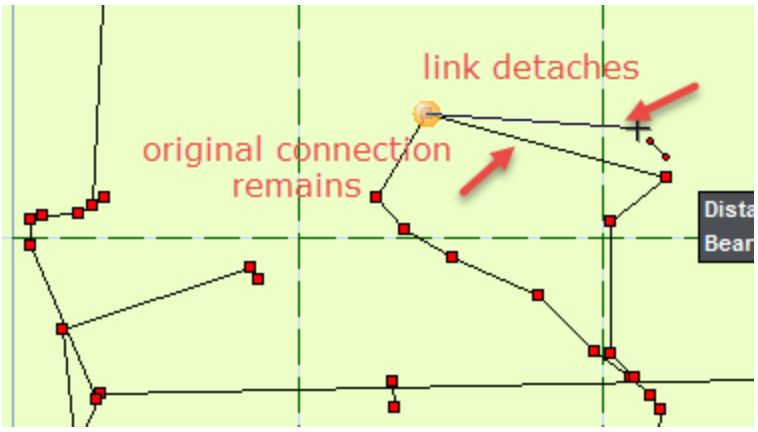
2. Click near the end of the link you want to reconnect.

   A highlight bubble displays on the opposite end of the link indicating that this is now the link's anchor point.



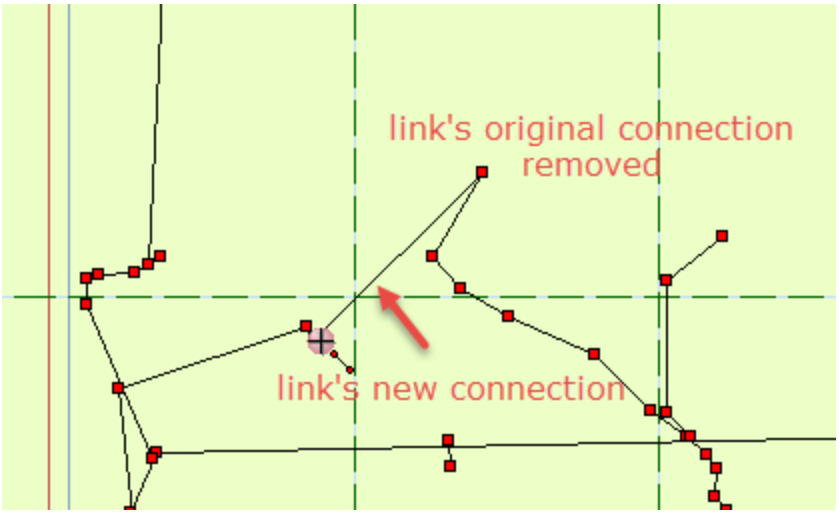
3. Drag the link to a new location.

   The link detaches. The original connection remains until the link is reconnected. Note that you can right-click at any time to exit reconnect link mode.



4. Click another facility or node to reconnect the link.

   The link's original connection is removed, and the link is reconnected to its new location.



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Working with an existing model

You need to make sure that your Piper model represents gathering system conditions. To do so, it is important to determine that the data is correct, such that it constrains the model to field conditions, and that appropriate correlations are being used.

The critical components to review for system calculations are:

- forecast period
- facility and link data, and configuration dates
- inputs for pressure loss correlation data
- model connectivity

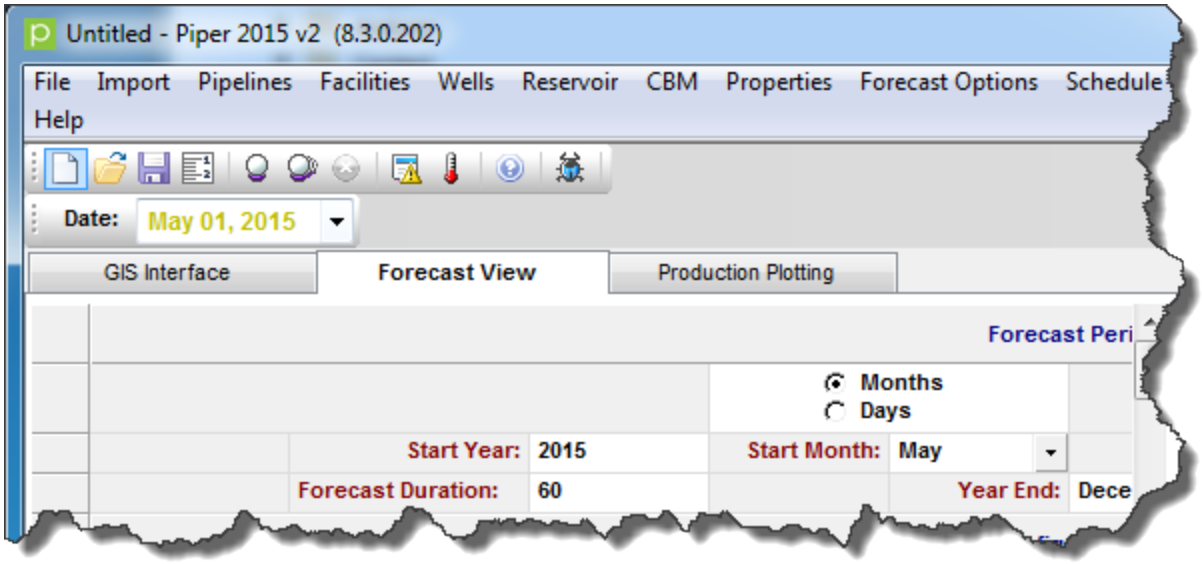
When you open an existing model, you may be prompted to locate missing files. For more information, see locating missing files.

Review your forecast

You need to make sure that forecast parameters and configuration change dates accurately reflect the gathering system through time.

To review your forecast:

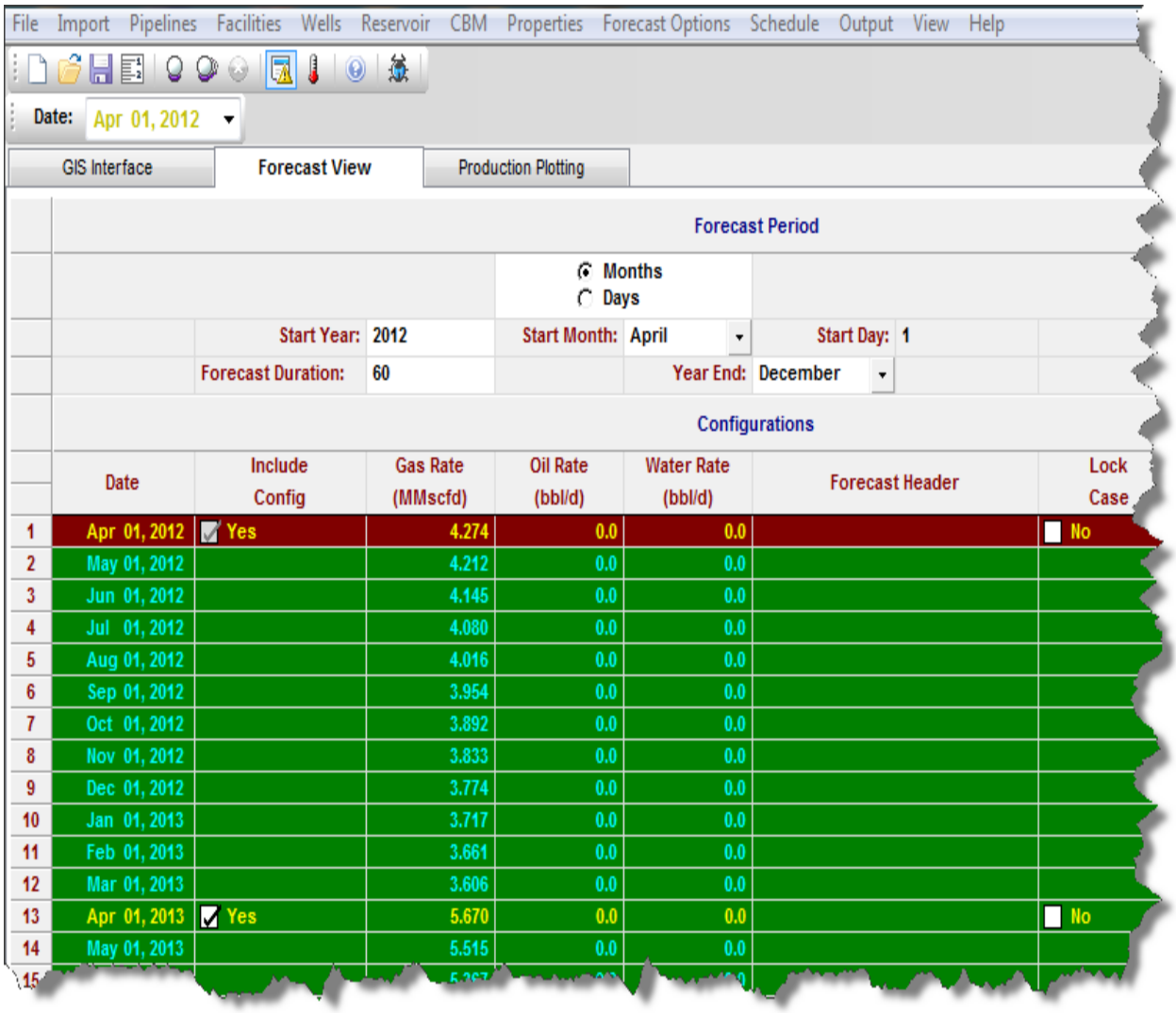
1. Click the **Forecast View** tab.



2. Make sure that the forecast period selection (Months or Days) applies to your model. (Days are only used with transient inflow models.)

3. Review the Configurations table and verify the accuracy of all configuration dates.

   Configuration dates are highlighted in yellow.



4. For each configuration date, review if different facility types have been added at these times.
5. If the configuration date does not apply, right-click any row in the table and select **Delete Cases**.

   The Select Cases To Delete dialog box opens.

6. Select each configuration date you want to delete and then click **OK**.
7. Make sure the Start Year and Forecast Duration occurs after the dates for the imported historical production data. For example, the start year should be after all imported historical production, and is typically the date you entered for your current production data.

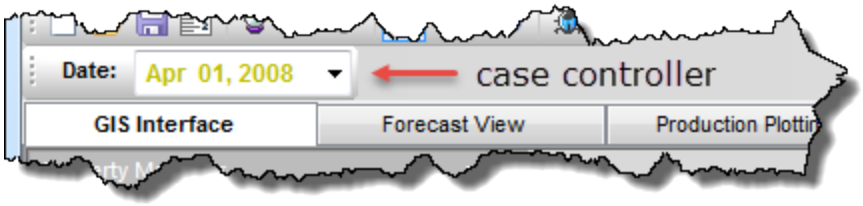
This completes the review of the forecast period.

Review facility and link data, and configuration dates

To make sure that your gathering system model accurately reflects the gathering system, you need to review: the facilities and links included in the model, facility and link data, and the configuration dates that reflect how the data changes throughout the forecast period.

To review this data:

1. Select the first configuration date in the case controller.



2. If you do not have the GIS interface tab selected, click the **GIS Interface** tab, and:

   a. Click the **Go To** icon (); a list of all facilities in the model is displayed in the Go To dialog box. Verify the facilities listed for the first configuration date are correct.

   b. If there are additional configuration dates, select the next date in the case controller. Repeat step a) and verify if any facilities have been added or deleted.

3. Click the **Facilities** menu and select each facility type identified in steps 2 a) and b).

   Or, right-click a facility on the map and select **Edit**.

   The editor for the selected facility type is displayed.

4. Verify that the data entered in the editor is valid.

5. In the date tree on the left side of the editor, expand each configuration date.

   The configuration of the model is listed for each configuration date. The entries are color-coded as follows:

   - green — new additions
   - red — existed in a prior configuration, but changes have been made, or the facility was deleted
   - black — unchanged and existed in a prior configuration

You can also verify changes made to the model by viewing the systems changes report.

6. Click **OK**.
7. Click the **Wells** menu and select **Well Editor**.

   Or, right-click a well on the map and select **Edit**.

   The Well Editor is displayed.

8. Repeat steps 4 - 6.
9. Click the **Pipelines** menu and select **Gathering System**.

   The Gathering System editor is displayed.

10. Repeat steps 4 - 6.

This completes the review of facility, link, and configuration dates.

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Verifying inputs for pressure loss correlation

Verify the inputs used for pressure loss correlations. The following components need to be reviewed:

- properties and correlation selection
- wellbore descriptions

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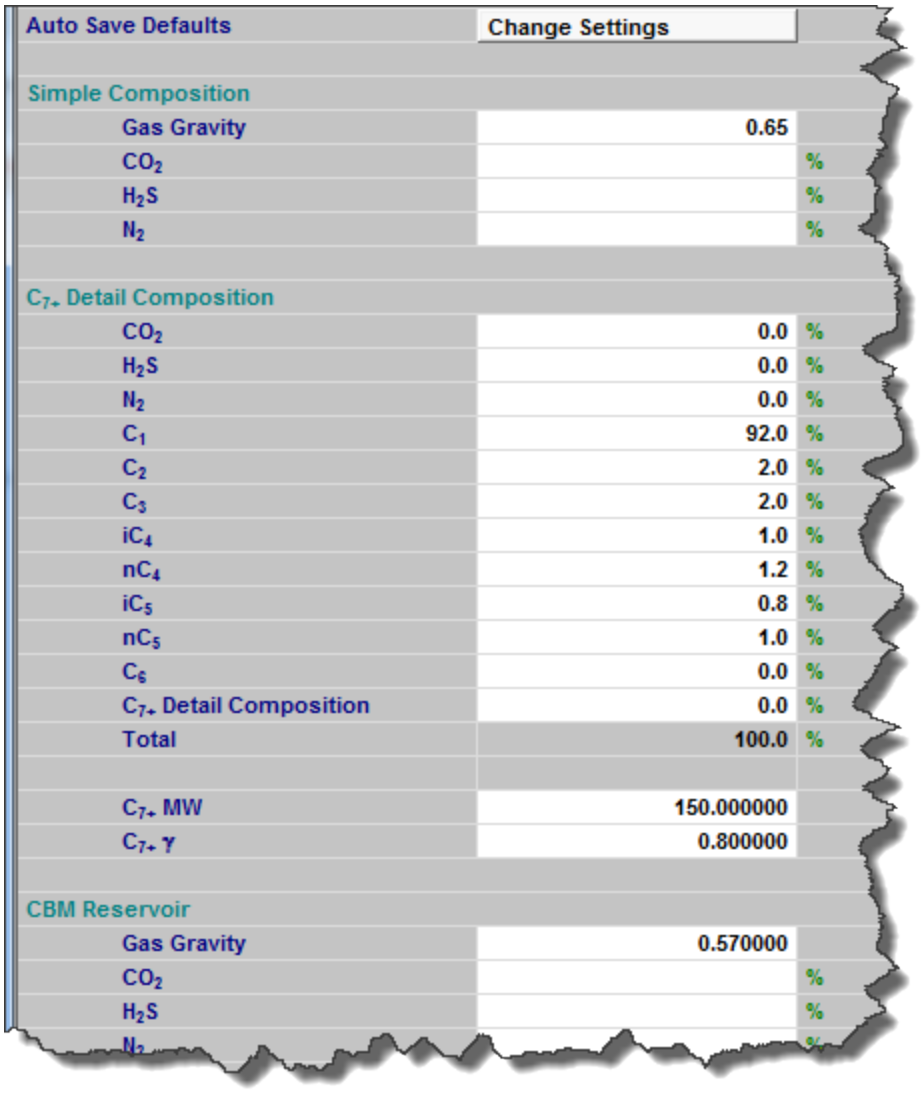
Verifying default property settings

To make sure that Piper models represent system conditions, you need to review the default properties settings.

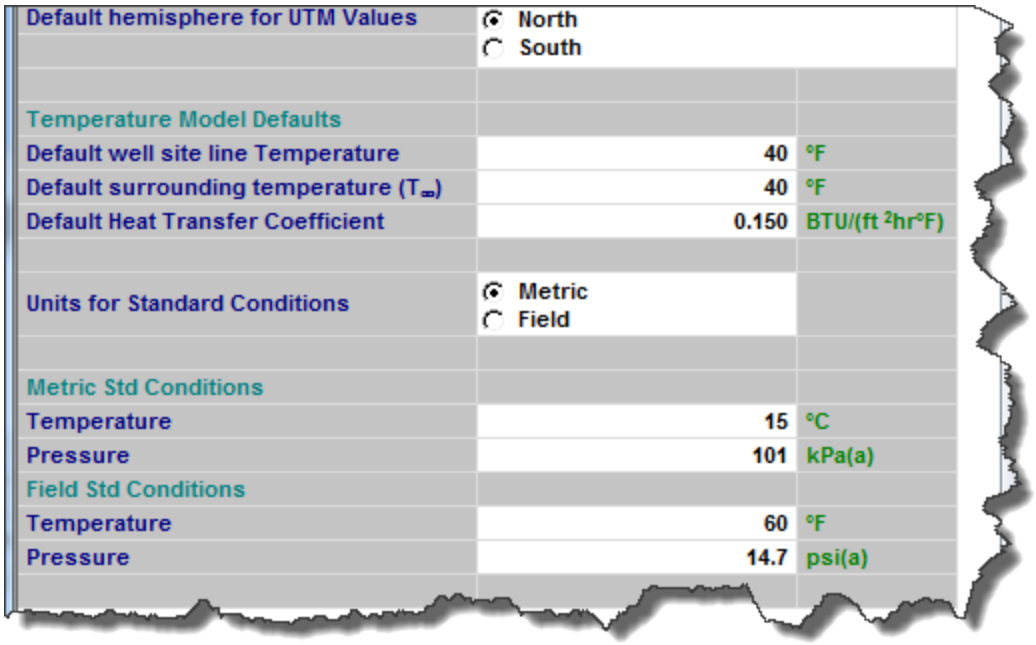
To verify default properties:

1. Click the **Properties** menu and select **Defaults**.
2. Review the global settings for fluid compositions and temperature.

   If required, make changes a global level.



Auto Save Defaults	Change Settings	
Simple Composition		
Gas Gravity	0.65	
CO_2		%
H_2S		%
N_2		%
C_{7+} Detail Composition		
CO_2	0.0	%
H_2S	0.0	%
N_2	0.0	%
C_1	92.0	%
C_2	2.0	%
C_3	2.0	%
iC_4	1.0	%
nC_4	1.2	%
iC_5	0.8	%
nC_5	1.0	%
C_6	0.0	%
C_{7+} Detail Composition	0.0	%
Total	100.0	%
C_{7+} MW	150.000000	
C_{7+} γ	0.800000	
CBM Reservoir		
Gas Gravity	0.570000	
CO_2		%
H_2S		%
N_2		%



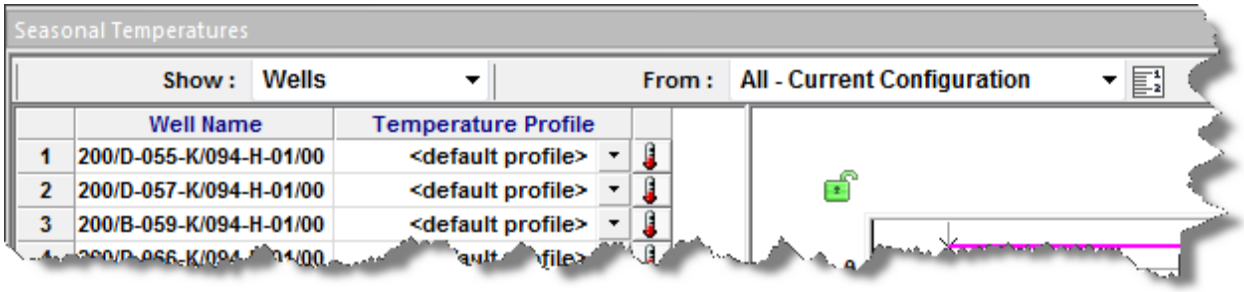
Default hemisphere for UTM Values	North / South	
Temperature Model Defaults		
Default well site line Temperature	40	°F
Default surrounding temperature (T_∞)	40	°F
Default Heat Transfer Coefficient	0.150	BTU/(ft ²hr°F)
Units for Standard Conditions	Metric / Field	
Metric Std Conditions		
Temperature	15	°C
Pressure	101	kPa(a)
Field Std Conditions		
Temperature	60	°F
Pressure	14.7	psi(a)

3. Click **OK**.

4. Click the **View** menu and select **Seasonal Temperatures**.

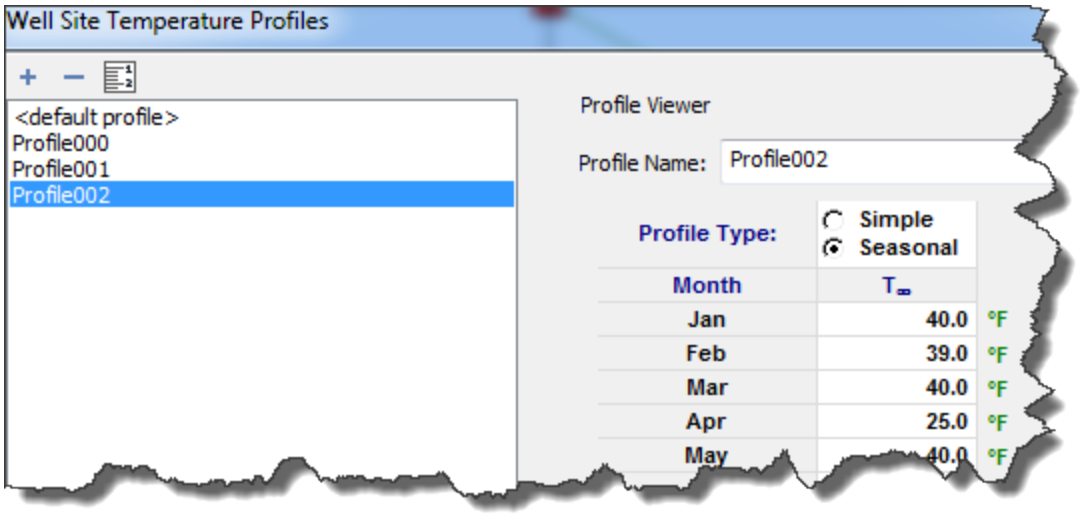
   The Seasonal Temperatures pane opens. If required, make adjustments to this data.

5. Select **Wells** from the **Show** drop-down list.



6. Click the **Seasonal Temperature** icon ( ) and review the temperature profiles for wells and then click **OK**.

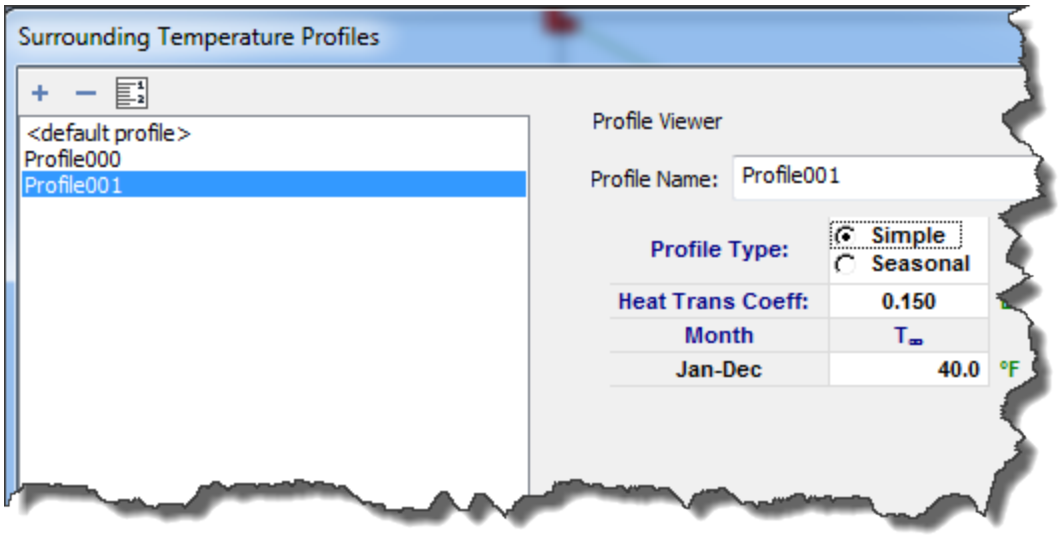
   If required, make adjustments to this data.



7. Select **Links** from the **Show** drop-down list.

8. Click the **Seasonal Temperature** icon ( ) and review the temperature profiles for links and then click **OK**.

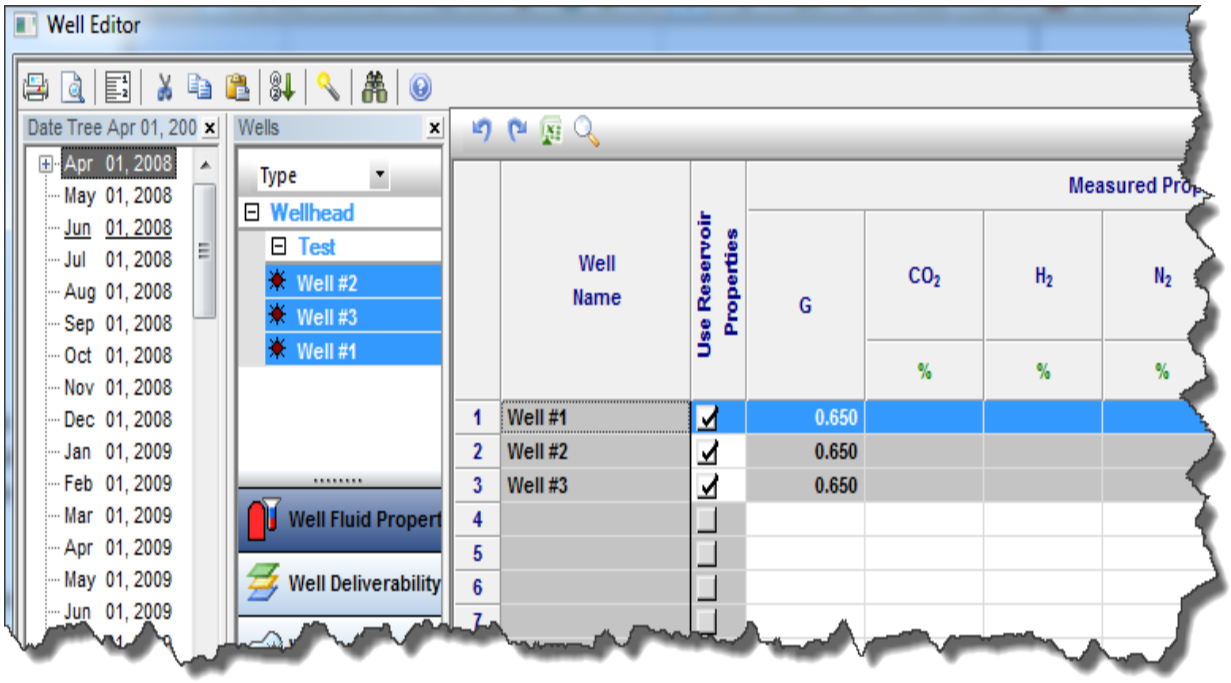
   If required, make adjustments to this data.



9. Click the **Wells** menu and select **Well Editor**.

   The Well Editor dialog box opens.

10. Click the**Well Fluid Properties** button and review or revise the individual well compositions.



11. Click the **Properties** menu and select **Correlations**.

    The Correlations dialog box opens.

12. Review the selected pressure loss correlation and the selected fluid correlation.

    If multiphase correlations are selected, make sure elevations are entered in the gathering system editor, and liquids are entered in the well deliverability editor.

    For more information on correlations, see setting correlations.

Verifying wellbore descriptions

To make sure that Piper models represent gathering system conditions (if you have wellbores in your model), you need to review the vertical wellbore parameters for Sandface C,n, and RTA type wells.

To verify wellbore descriptions:

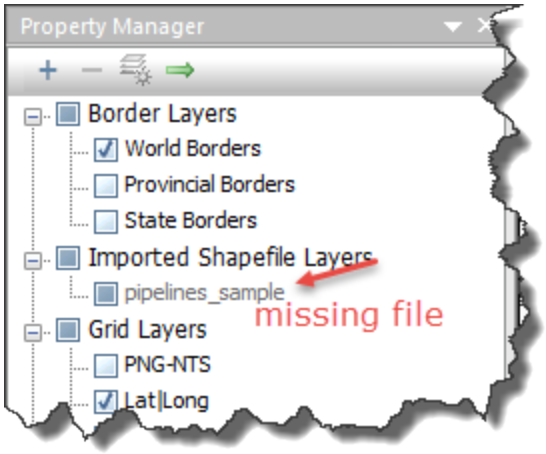
1. Click the **Wells** menu and select **Well Editor** > **Wellbore Descriptions**.
2. Review the flow path tubular data. If required, make adjustments to this data.
3. Review the Liquid Lift Correlation, Method Used When Well Loads, and Multiphase Pressure Loss Correlation data.

   If liquid loading occurs, these parameters can affect a well's production.

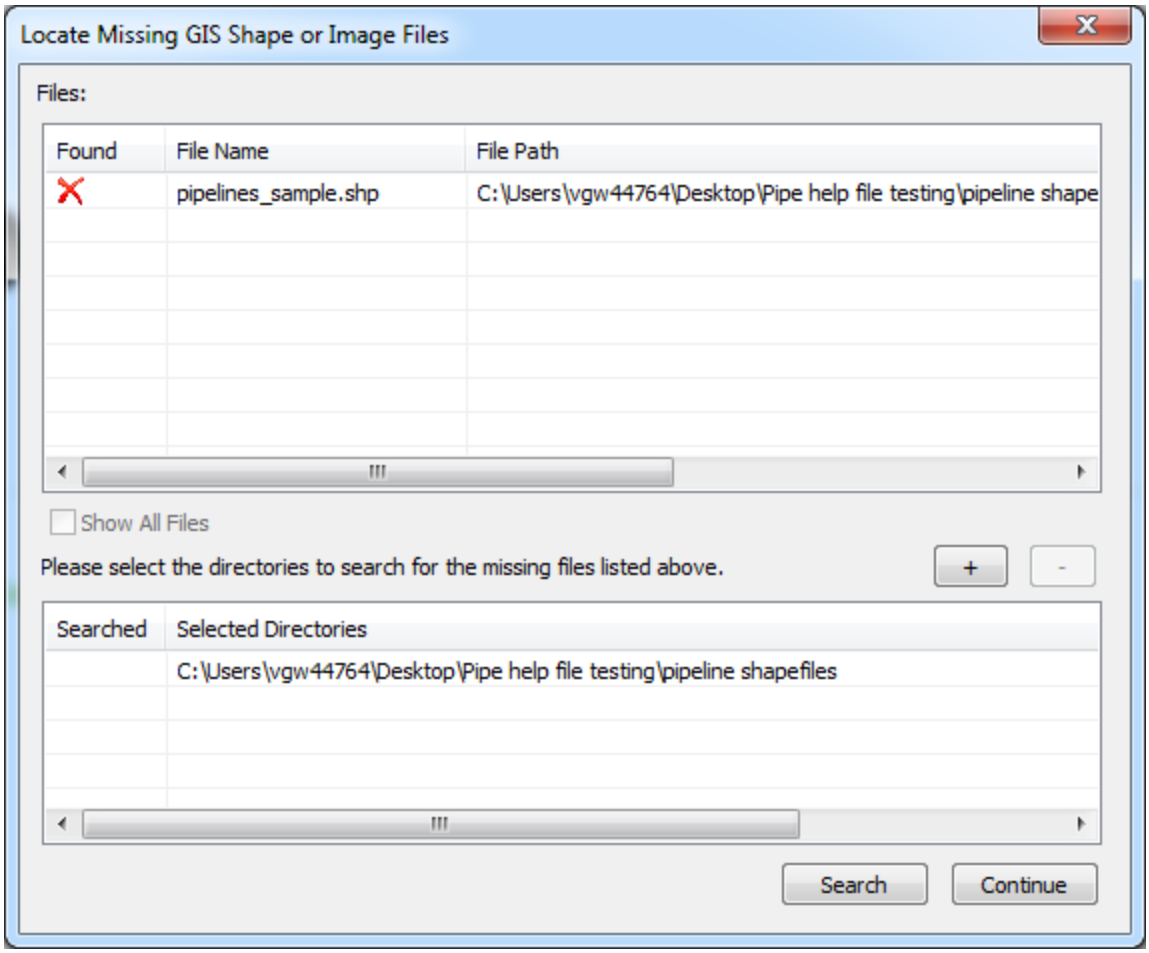
Note: Items displayed in blue are not used in the model calculations.

Locating missing files

When a shape or image layer file is added to a project, the content is referenced using a link to a directory path (it is not copied to the project file). If the file is moved to a new location, this invalidates the previously saved directory path. This most commonly occurs when files are shared between users, or when files are re-organized. When the directory path for a layer is invalid, its name is grayed-out, and it is not used by the application (see below).



If you have an invalid directory path, the Locate Missing GIS Shape or Image Files dialog box opens. This dialog box lists all missing layer files and their invalid file paths in the top table. The icon indicates that these files are missing and need to be located. The dialog box also lists all paths previously selected for search in the bottom table. By default, this dialog box only displays layer files that are currently missing. If you have previously opened the project and found some, but not all missing files, then the Show All Files checkbox is enabled. You can select this checkbox to list all files used by the project (not just the ones that are currently missing).



Note: If you click Continue without locating the missing file or without performing a search, the file is not available in Piper.

To locate missing files:

1. Click + to select the directories you want to search.

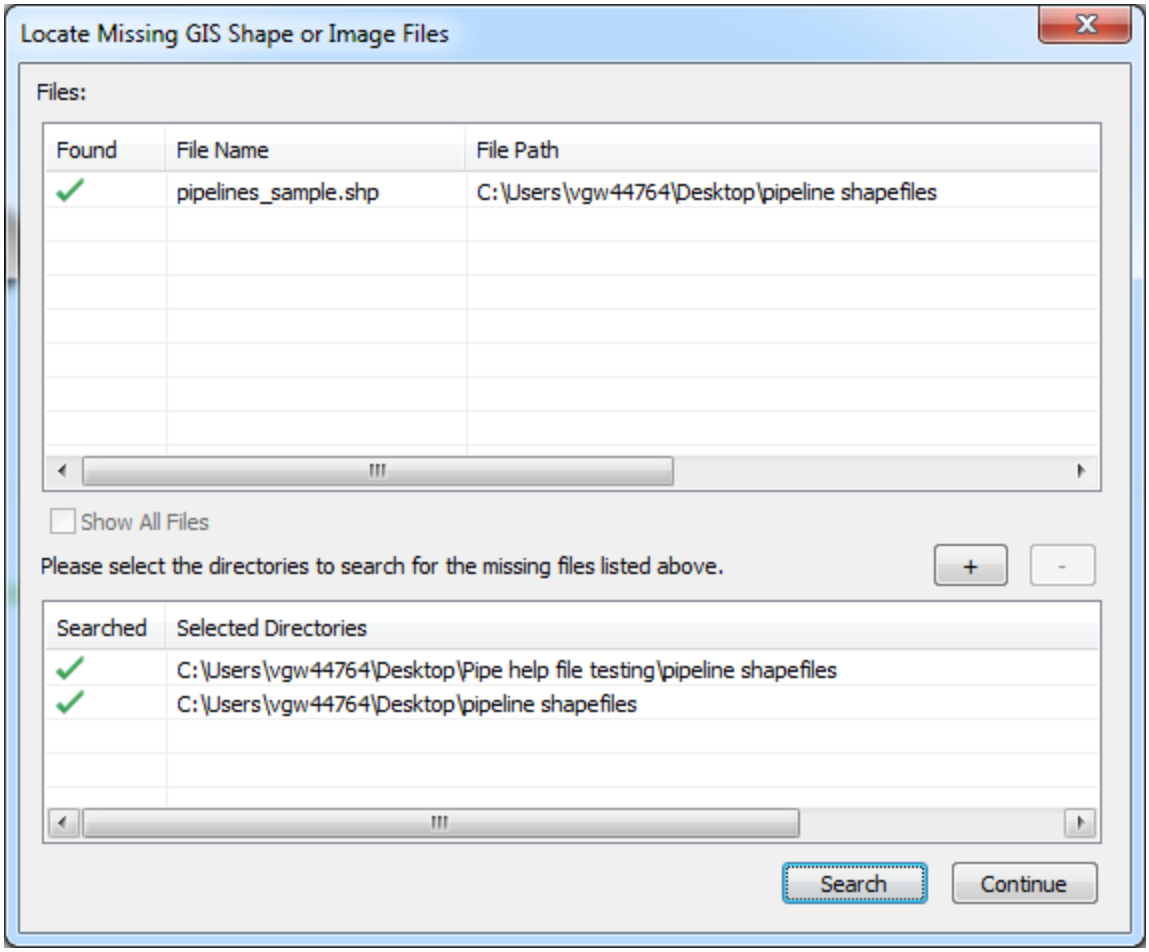
   Each selected directory is added to the list of Selected Directories. Note that Piper also searches all subdirectories.

2. (Optional) If you want to remove a directory from the search, select the directory and click -.

3. Click **Search**.

   If a missing file is found, a ✓ is displayed in the Found column, and its file path is updated.

Any directory you have searched is identified by a ✓ in the Searched column, and is saved for future use.



4. Click **Continue** to open Piper.

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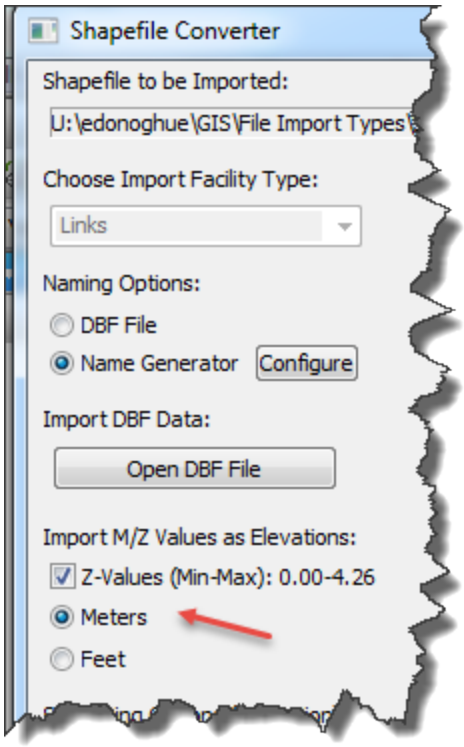
Adding elevations

Piper uses elevation data when running multiphase pressure loss calculations.

To include elevation change data for multiphase pressure loss calculations:

1. Import elevation data into Piper from a shapefile when you convert a shapefile to facilities or links.
2. Select the **Z-Values** checkbox in the Shapefile Converter dialog box, and select the applicable units.

   If a shapefile does not have elevation data, the Z-Values checkbox in the Shapefile Converter dialog box is disabled.



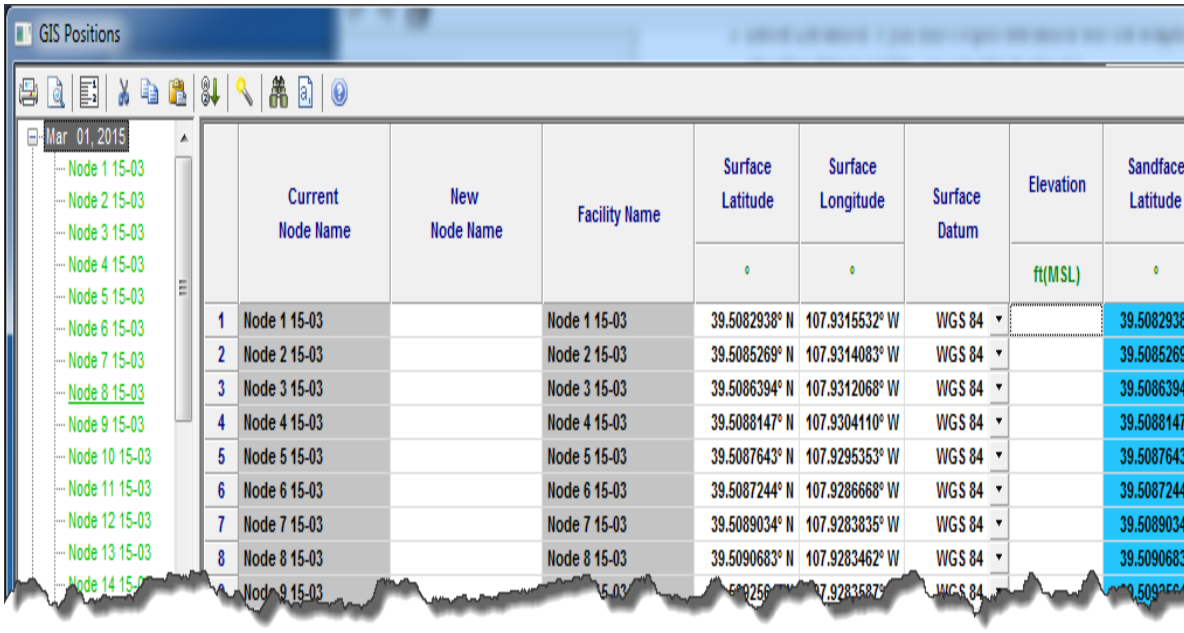
Elevations are displayed in the GIS Positions dialog box after they are imported.

Or, enter elevation data manually in the GIS Positions dialog box.

a. Click the **Pipelines** menu and select **GIS Positions**.

   The GIS Positions dialog box opens.

b. Enter the elevation data for each node in the **Elevation** column.



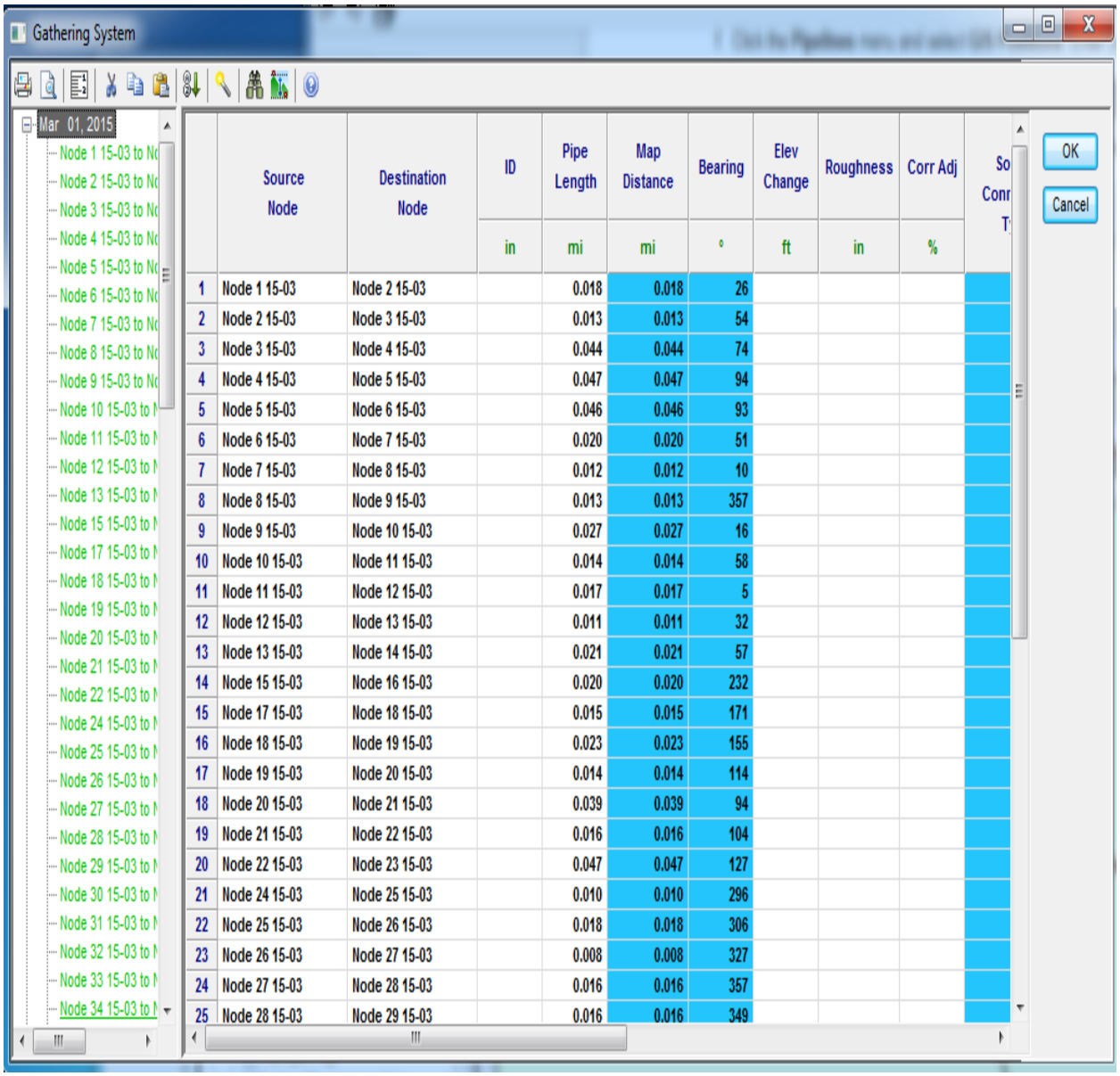
	Current Node Name	New Node Name	Facility Name	Surface Latitude	Surface Longitude	Surface Datum	Elevation	Sandface Latitude
				°	°		ft(MSL)	°
1	Node 1 15-03		Node 1 15-03	39.5082938° N	107.9315532° W	WGS 84		39.5082938
2	Node 2 15-03		Node 2 15-03	39.5085269° N	107.9314083° W	WGS 84		39.5085269
3	Node 3 15-03		Node 3 15-03	39.5086394° N	107.9312068° W	WGS 84		39.5086394
4	Node 4 15-03		Node 4 15-03	39.5088147° N	107.9304110° W	WGS 84		39.5088147
5	Node 5 15-03		Node 5 15-03	39.5087643° N	107.9295353° W	WGS 84		39.5087643
6	Node 6 15-03		Node 6 15-03	39.5087244° N	107.9286668° W	WGS 84		39.5087244
7	Node 7 15-03		Node 7 15-03	39.5089034° N	107.9283835° W	WGS 84		39.5089034
8	Node 8 15-03		Node 8 15-03	39.5090683° N	107.9283462° W	WGS 84		39.5090683

c. Click **OK**.

3. Click the **Pipelines** menu and select **Gathering System**.

   The Gathering System dialog box opens.

4. Click the **Calculate Link Elevation Change** icon ( ) to calculate link elevation change.



	Source Node	Destination Node	ID	Pipe Length	Map Distance	Bearing	Elev Change	Roughness	Corr Adj	So Conn T
			in	mi	mi	°	ft	in	%	
1	Node 1 15-03	Node 2 15-03		0.018	0.018	26				
2	Node 2 15-03	Node 3 15-03		0.013	0.013	54				
3	Node 3 15-03	Node 4 15-03		0.044	0.044	74				
4	Node 4 15-03	Node 5 15-03		0.047	0.047	94				
5	Node 5 15-03	Node 6 15-03		0.046	0.046	93				
6	Node 6 15-03	Node 7 15-03		0.020	0.020	51				
7	Node 7 15-03	Node 8 15-03		0.012	0.012	10				
8	Node 8 15-03	Node 9 15-03		0.013	0.013	357				
9	Node 9 15-03	Node 10 15-03		0.027	0.027	16				
10	Node 10 15-03	Node 11 15-03		0.014	0.014	58				
11	Node 11 15-03	Node 12 15-03		0.017	0.017	5				
12	Node 12 15-03	Node 13 15-03		0.011	0.011	32				
13	Node 13 15-03	Node 14 15-03		0.021	0.021	57				
14	Node 15 15-03	Node 16 15-03		0.020	0.020	232				
15	Node 17 15-03	Node 18 15-03		0.015	0.015	171				
16	Node 18 15-03	Node 19 15-03		0.023	0.023	155				
17	Node 19 15-03	Node 20 15-03		0.014	0.014	114				
18	Node 20 15-03	Node 21 15-03		0.039	0.039	94				
19	Node 21 15-03	Node 22 15-03		0.016	0.016	104				
20	Node 22 15-03	Node 23 15-03		0.047	0.047	127				
21	Node 24 15-03	Node 25 15-03		0.010	0.010	296				
22	Node 25 15-03	Node 26 15-03		0.018	0.018	306				
23	Node 26 15-03	Node 27 15-03		0.008	0.008	327				
24	Node 27 15-03	Node 28 15-03		0.016	0.016	357				
25	Node 28 15-03	Node 29 15-03		0.016	0.016	349				

Click to show / hide an explanation for the link elevation converter...

a. Start at the source node of the first entry in the gathering system.

b. If there is an absolute elevation for this node in the GIS Position editor, make this the zero value for the elevation change of the gathering system. If the elevation is empty, navigate to the next node (i.e., destination node of row one, source node of row two, destination node of row two, etc.) until the value is not blank. This will be the zero value. Since all previous nodes are blank, they are considered to be the same elevation and are assigned a zero elevation change. Or, if there is a value already entered in the gathering system, do not change it.

c. Now we have a starting point for the elevation. Navigate through the Gathering System editor and calculate the relative difference for the elevation change between each node. Replace the old value if it exists. If either source, the destination or both nodes are blank, the elevation change for that link will be zero. Or, if there is a value in the elevation change, do not change it.

5. Click **OK**.

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Make sure you have model connectivity

In order to run calculations on your gathering system model, you must make sure that all links in your model are connected to a delivery point. If your links are not connected to a delivery point, pressure loss is not calculated.

Ensure you identify and correct:

- unused facilities
- disconnected links

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Unused facilities

Unused facilities are facilities that are not connected to your gathering system. This can result in a model that does not represent operating conditions.

To view and correct unused facilities:

1. Click the **Facilities** menu and select **Unused Facilities**.

   The Unused Facilities dialog box opens listing all facilities that are unused.

2. Copy the contents of the Unused Facilities dialog box to Excel.

3. Click **OK**.

4. Click the **Go To** icon ().

5. Copy a facility name from the unused facilities data in your Excel spreadsheet to the Name field of the Go To dialog box.

   The facility is highlighted in the facility tree on the right-side box and the Go To button is enabled.

6. Click **Go To**.

   The map centers on the selected facility.

7. Determine if this facility needs to be connected to the gathering system.

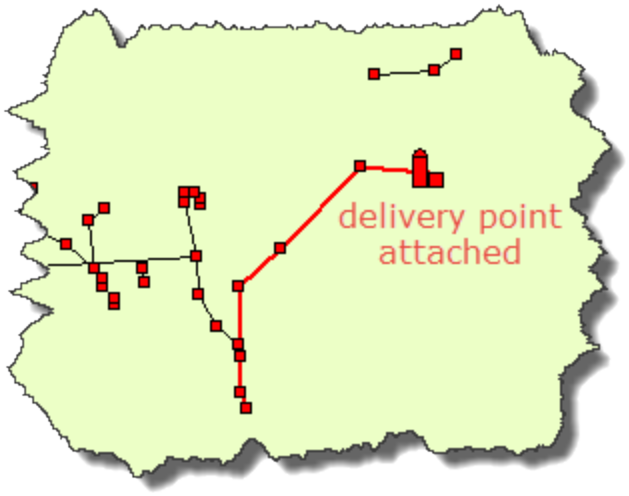
   If the facility needs to be connected, see adding links, or reconnecting links.

Disconnected links

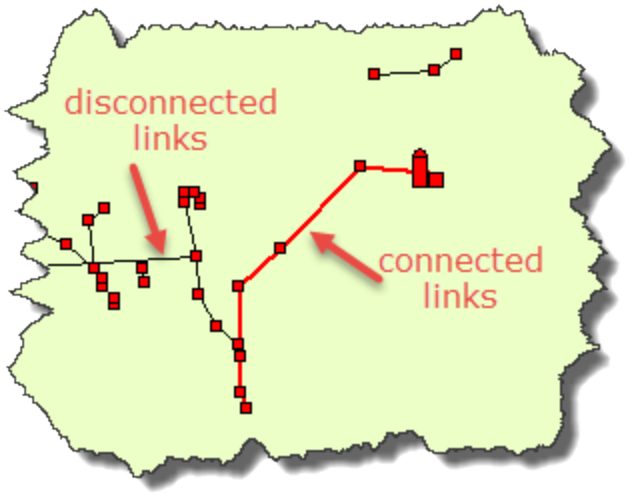
A fully connected model displays links as wide lines based on your settings in the Link Colors dialog box. You can define link colors and line widths by clicking the **Properties** menu and selecting **Link Colors**. Disconnected links display as thin black lines.

To test your model for disconnected links:

1. Make sure at least one delivery point is connected to your gathering system. For more information on attaching a delivery points, see unused facilities.

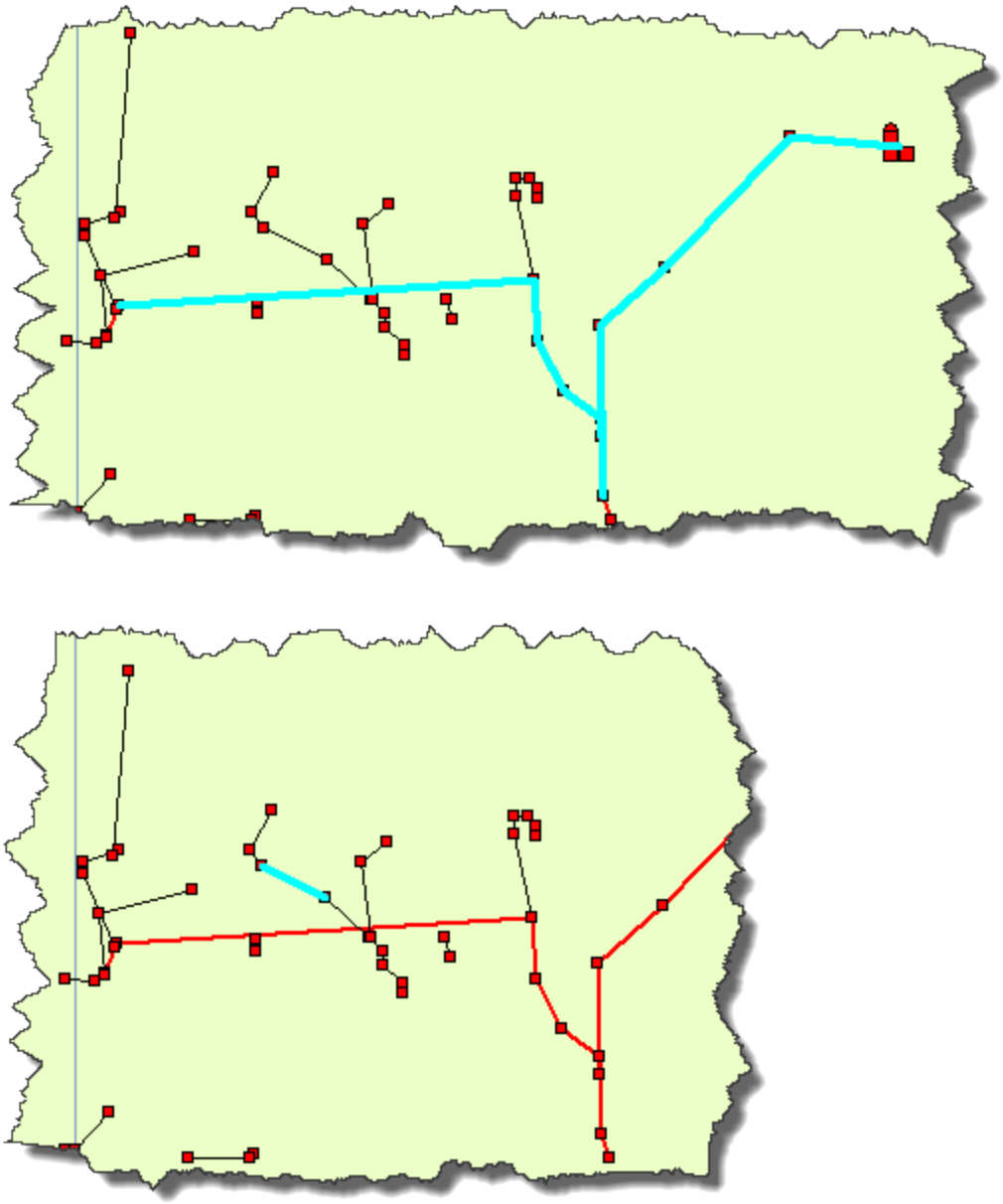


2. Identify disconnected links:
    - look for thin black lines



If you imported your links from a shapefile, the shapefile is displayed as thin black lines. Deselect the shapefile in the Property Manager to hide the shapefile on the map. This makes it easier to identify disconnected links.

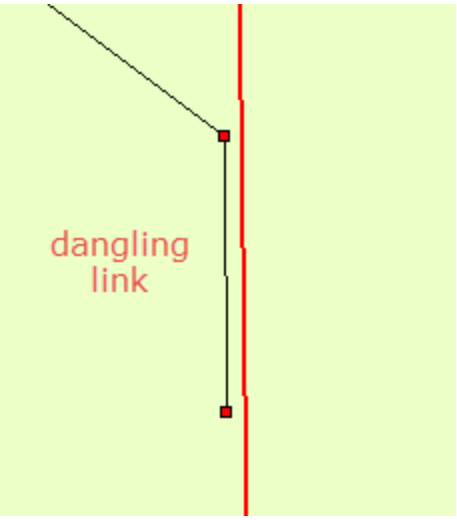
- use the shortcut key Ctrl+L



Link segments that are connected are highlighted in one continuous light blue line; disconnected links are highlighted in a light blue line, which is just for the link segment.

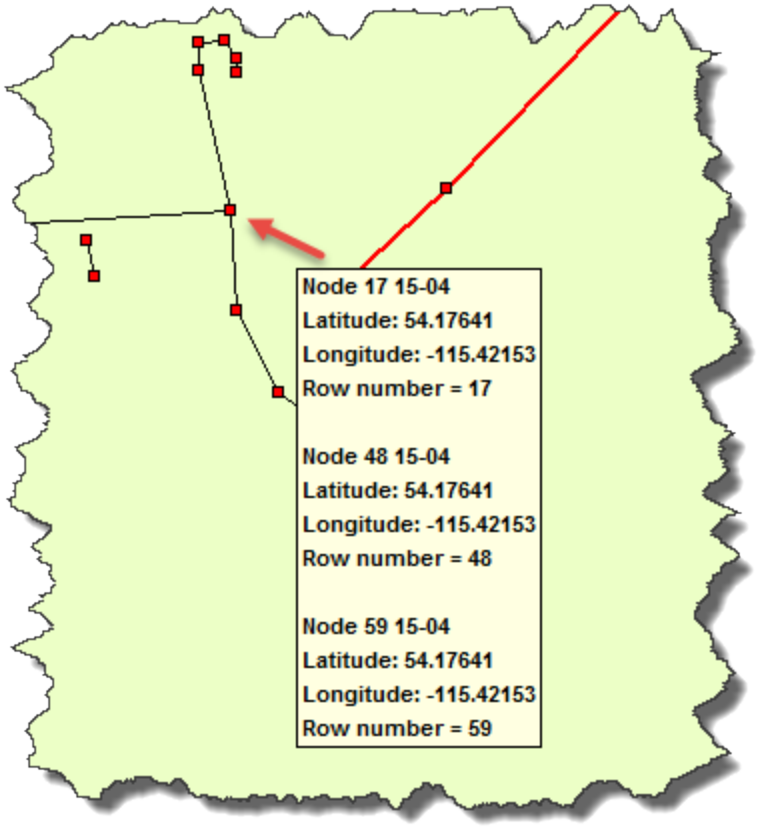
3. Zoom in to the disconnected link:

- verify if it is a dangling link

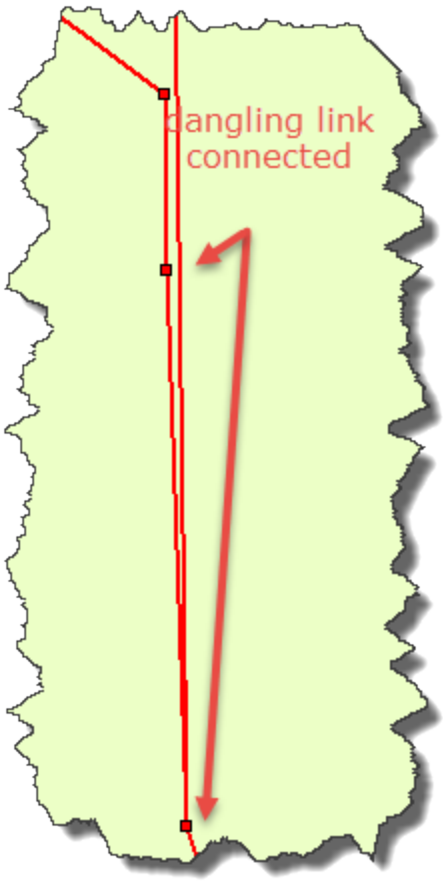


- verify if there are there multiple nodes for a link's endpoints

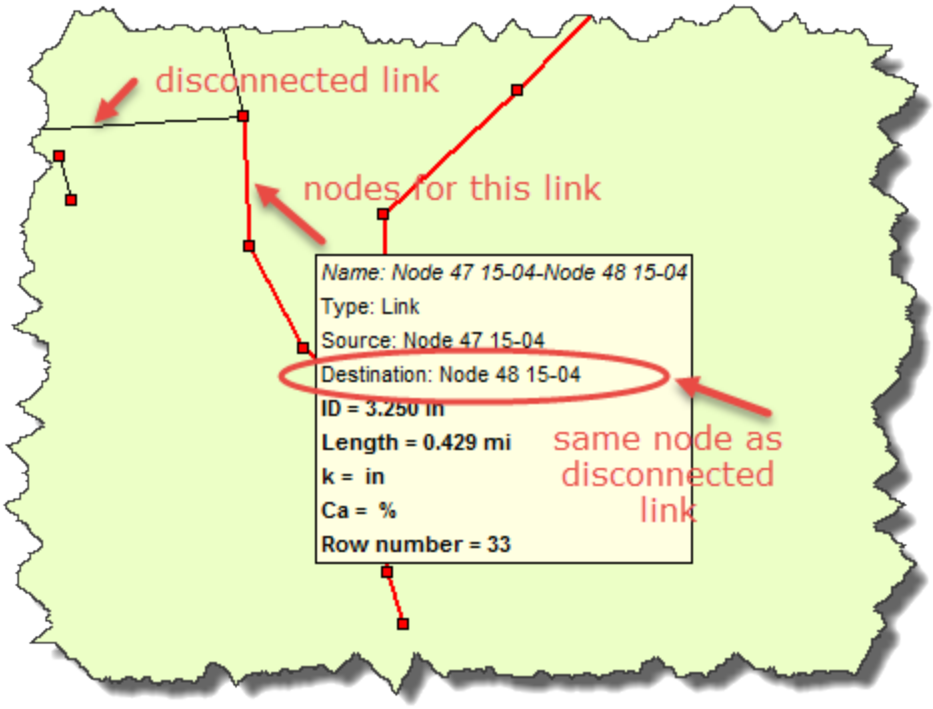
  Hover over the link's endpoint; a tooltip listing the nodes at that location is displayed.



4. If the disconnected link is a dangling link, attach it to an existing link that is connected to the gathering system.



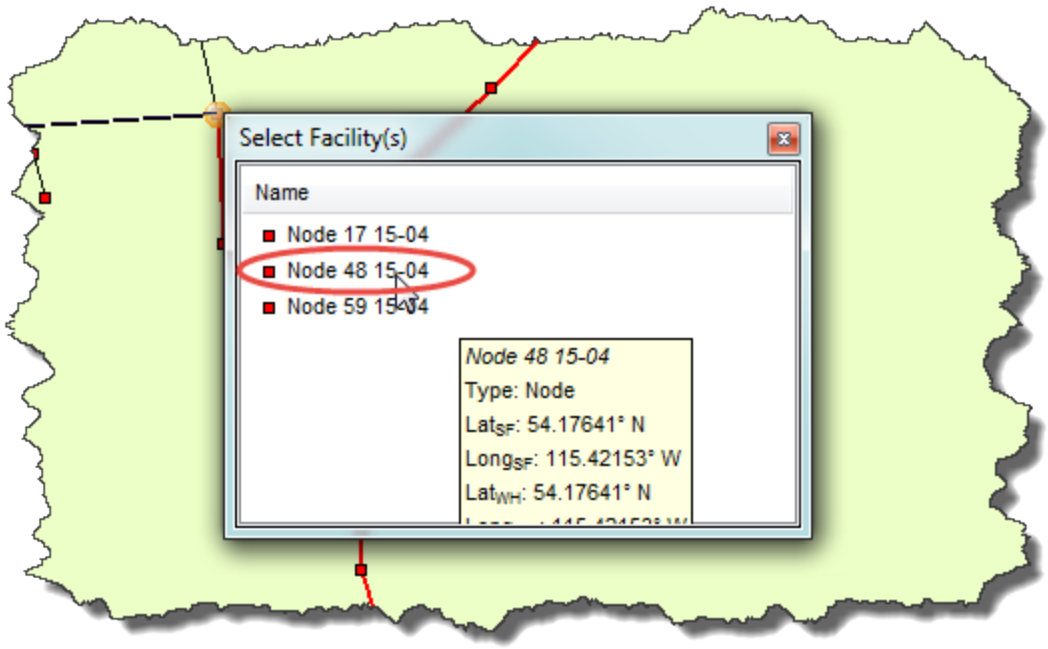
5. If the disconnected link has multiple nodes listed at one of its endpoints, hover over a link adjacent to the disconnected link, and verify if one of its endpoints is one of the multiple nodes listed for the disconnected link.



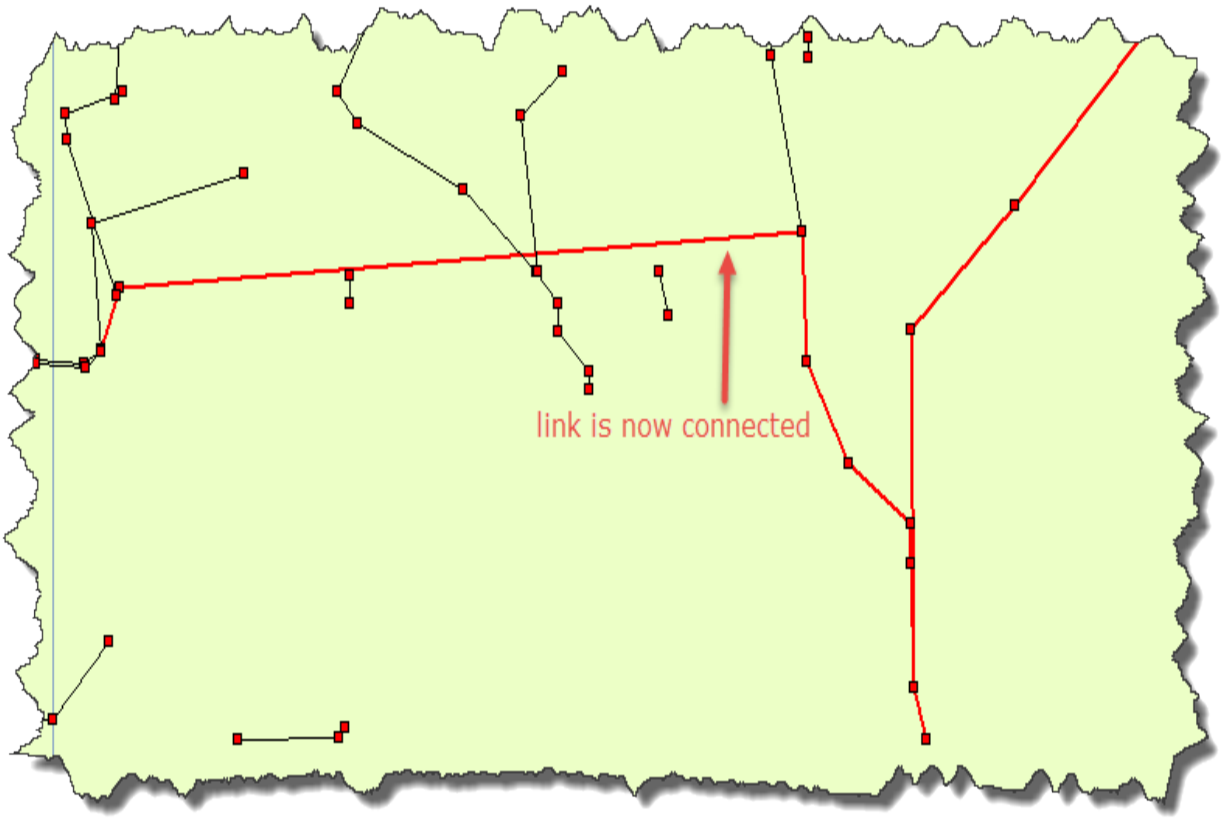
6. If the adjacent link has one of the same endpoints as the disconnected link, reconnect the disconnected link to the same node.

   A highlight bubble is displayed and at the reconnection point, and a dialog box is displayed prompting you to select the node to reconnect to.

   Select the node of the connected link.



The link is displayed as a wide line indicating it is now connected to the gathering system.



7. Repeat steps 2-6 until your gathering system is fully connected.

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Adding a temperature profile

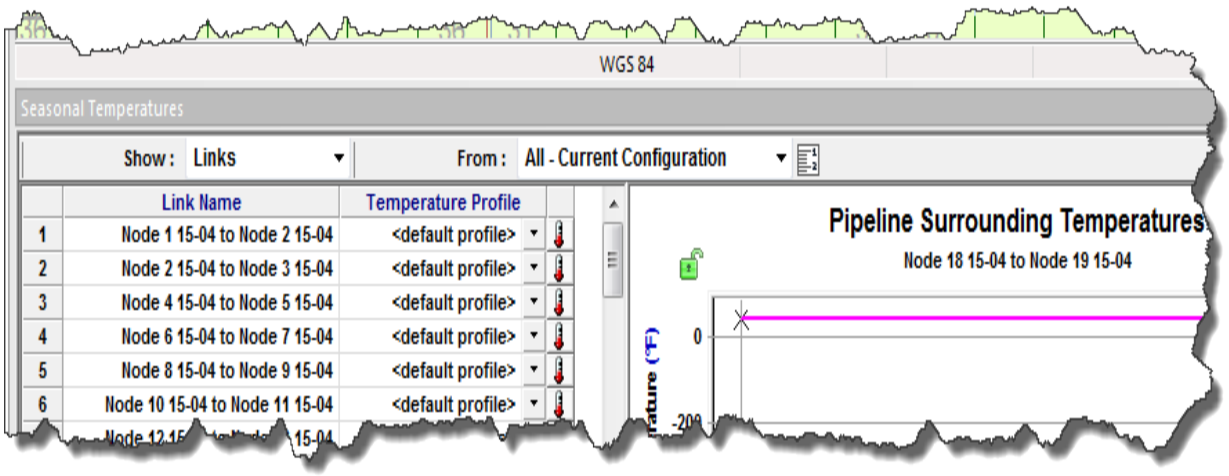
You may want to add a temperature profile to your gathering system model to predict fluid properties.

From the Seasonal Temperatures editor, you can enter field temperature information in your gathering system model, specifically the wellsite line and pipeline ground temperatures. Using these temperatures, Piper calculates heat loss and the corresponding changes in fluid temperatures as fluid travels in the pipe. Changes in temperature affect PVT calculations (if PVT is selected in your correlations).

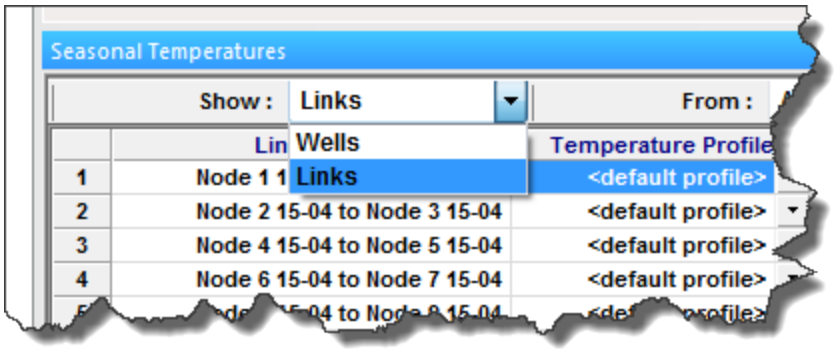
To add a temperature profile:

1. Click the **View** menu and select **Seasonal Temperatures**, or click the  icon in the main toolbar.

   The Seasonal Temperatures pane opens at the bottom of the window.



2. Select either **Wells** or **Links** from the **Show:** list.

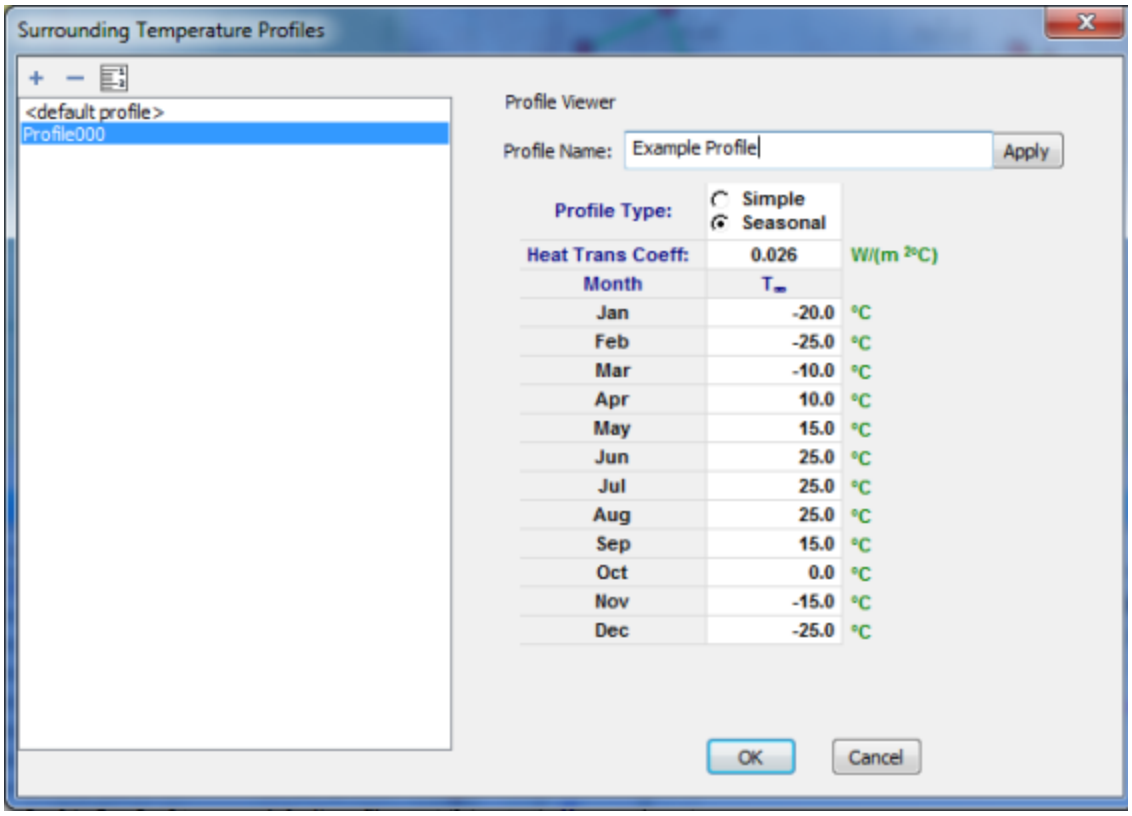


3. Select the list of entities you want to display in the **From** list:

   - **Selected** — the wells or links listed are only those that are selected on the map.
   - **All - Current Configuration** — the wells and links listed are only those that are present in the current configuration (the configuration currently selected in the case controller).
   - **All – All Configurations** — the wells and links listed are those present in all configurations.

4. Select the entity you want to edit and then click the **Temperature** icon ( ) displayed next to the entity.

   For wells, the Well Site Temperature Profiles dialog box opens. For links, the Surrounding Temperature Profiles dialog box opens.



5. Click the + icon.

   A new profile is added to the left-side box and the Profile Name field is enabled.

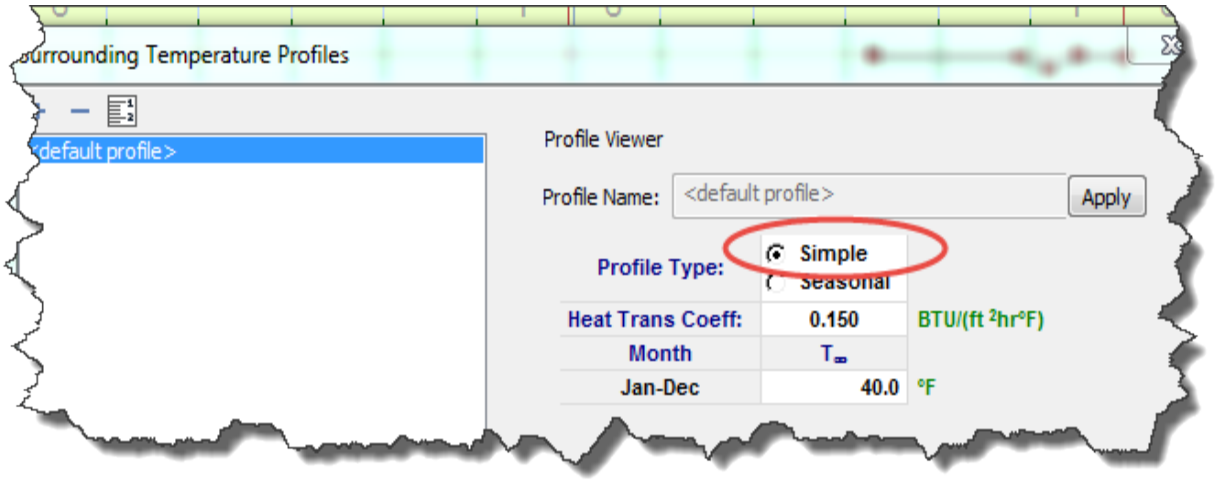
6. Enter a profile name for your temperature profile.

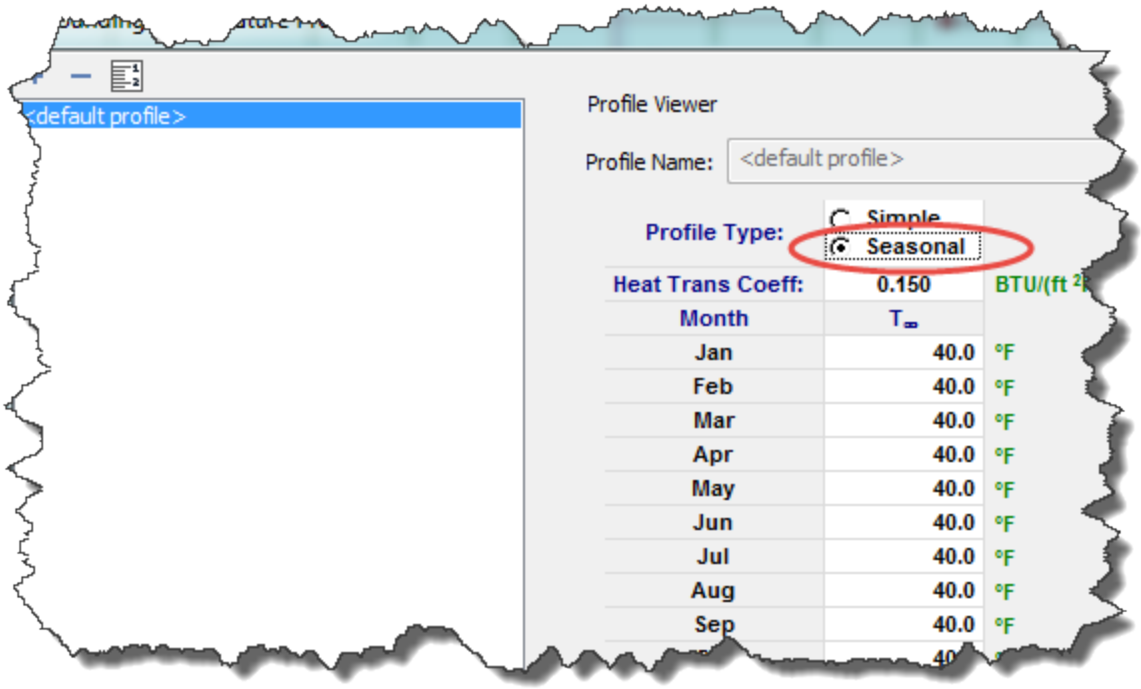
7. Click **Apply**.

   The profile name is updated in the left-side box.

8. Select **Simple** or **Seasonal** as the Profile Type.

   Simple temperatures apply a single temperature value for each forecast period. For seasonal temperatures, you must enter these values on a month-to-month basis, which are applied to each year of the monthly forecast period.





9. For links, enter the heat transfer coefficient (the rate that heat is transferred from the fluid in the pipe to the surrounding environment).
10. Click **OK**.
11. Select the profile from the drop-down list in the **Temperature Profile** column.

The temperature profile is applied to the selected entity and is displayed in the plot to the right.

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Setting correlations

These procedures relate to setting correlations:

- defining compositions
- defining pressure loss correlations
- defining fluid correlations

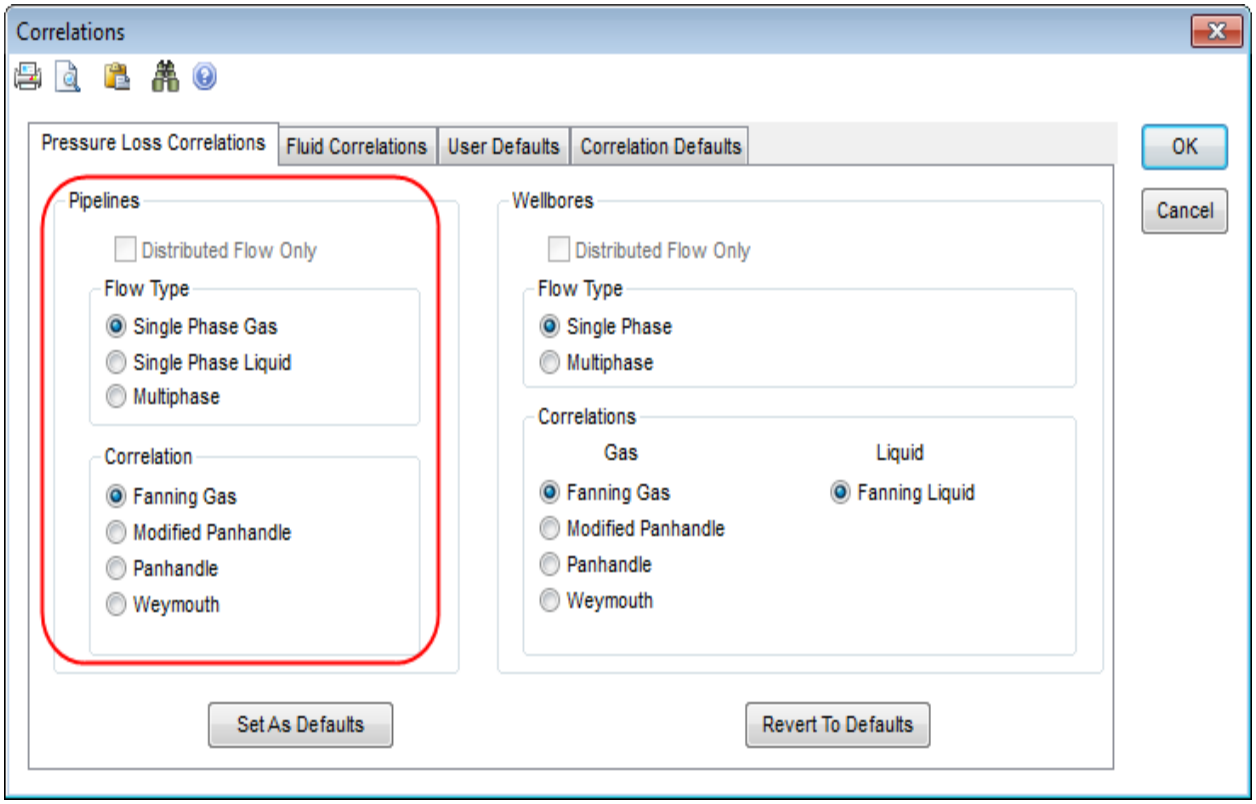
Defining pressure loss correlations

Pressure loss correlations are set independently for pipelines and wellbores. After you select the flow type and correlation, they are applied by default to all pipelines and wellbores. For wellbores only, you can select flow type and correlation properties individually in the Well Editor > Wellbore Descriptions pane.

To define your pressure loss correlations:

1. Click the **Properties** menu and select **Correlations**.

   The Correlations dialog box opens. The Pressure Loss Correlations tab is selected by default.



2. Select a Pipelines **Flow Type**:

   - Single Phase Gas — ignores all liquid rates in your pipelines
   - Single Phase Liquid — ignores all gas rates in your pipelines, used for oil pipelines
   - Multiphase — significant amounts of both gas and liquid coexist in the same pipeline

Note: If you are selecting single-phase oil or gas, make sure you update your convergence settings.

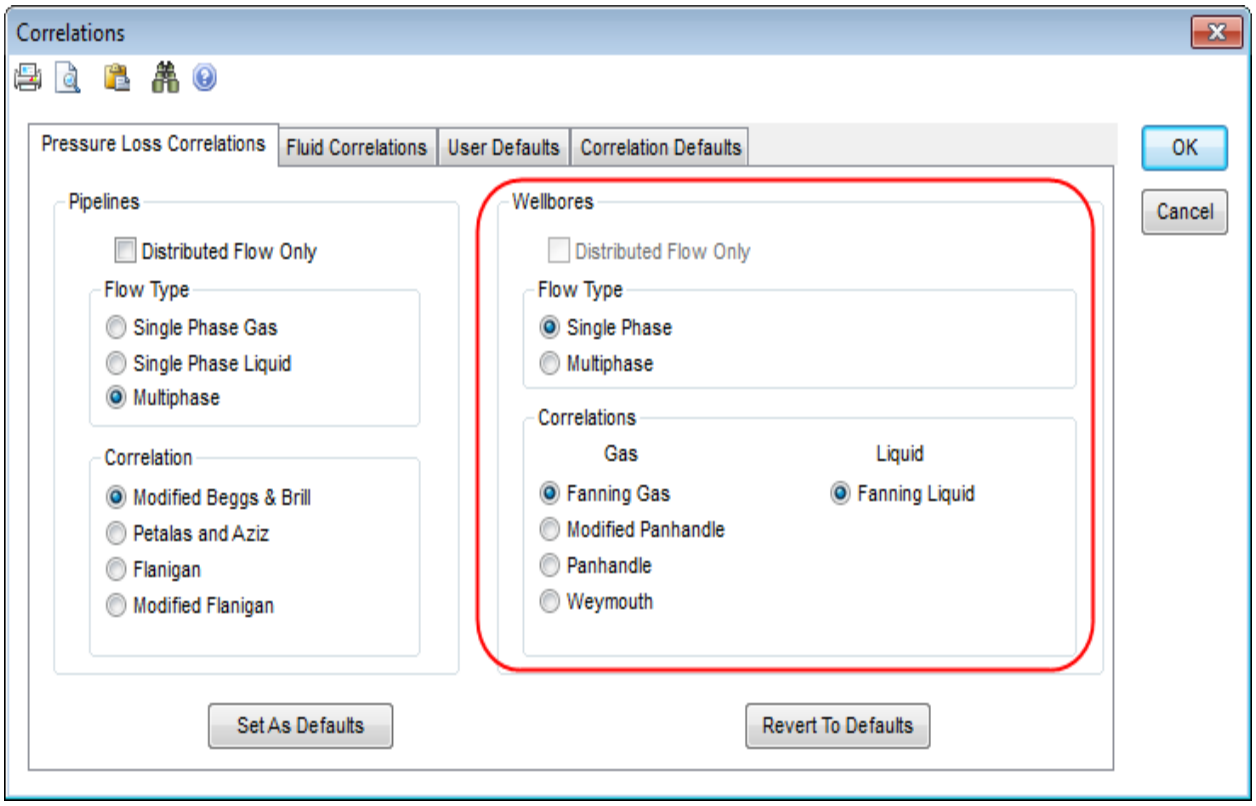
3. Select a Pipelines **Correlation**:

Flow Type	Correlation
Single Phase Gas	Recommended - Fanning Gas (rigorous) (Optional) - Modified Panhandle, Panhandle and Weymouth
Single Phase Liquid	Fanning Liquid Modified Beggs & Brill and Petalas & Aziz- any liquid-to-gas ratio
Multiphase	Flanigan and Modified Flanigan - intended for gas systems with a small amount of liquid

Note: If multiphase flow and Beggs & Brill correlation are selected, then the Distributed Flow Only checkbox is enabled. Beggs & Brill has four flow patterns: distributed, transitional, intermittent, and segregated. Selecting Distributed Flow Only restricts Beggs & Brill to the distributed flow pattern.

4. Select a Wellbores **Flow Type**.

Single Phase Liquid cannot be selected for wellbores.



- Single Phase— only considers gas or liquid in the wellbore
- Multiphase — significant amounts of both gas and liquid coexist in the same wellbore

5. Select a Wellbores **Correlation**:

Flow Type	Correlation
	Recommended - Fanning Gas or Fanning Liquid (rigorous)
Single Phase	(Optional) - Modified Panhandle, Panhandle and Weymouth
Multiphase	For information on wellbore correlation selections (Modified Beggs & Brill, Gray, and Hagedorn & Brown) see pressure loss correlations

6. To save these settings as your default, click **Set As Defaults**.

   Your settings are populated in the User Defaults tab and can be used to revert pressure-loss-correlation changes made at a later point in time.

7. Click **OK**.

Defining fluid correlations

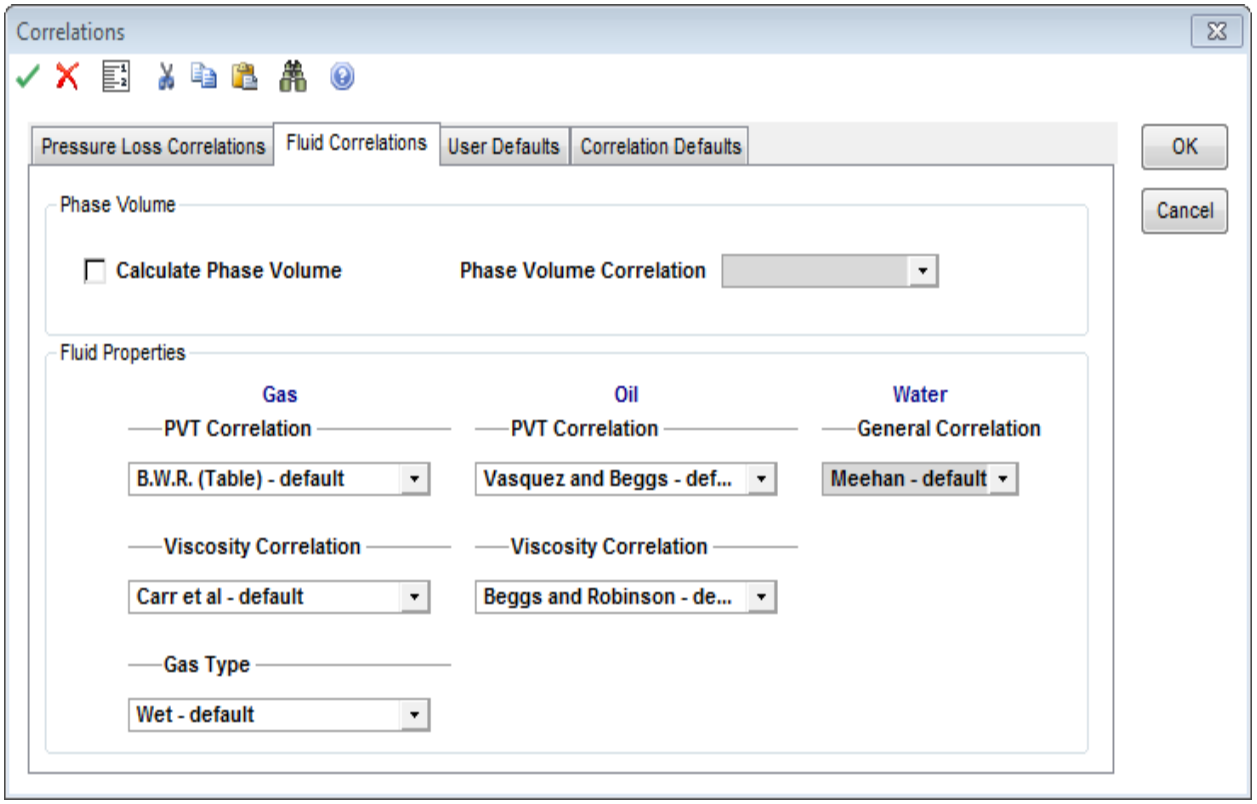
Fluid correlations are used to determine properties that are based on pressure, temperature, and fluid composition. Examples of some of these properties are: formation volume factor, density, and viscosity. For more information, see well fluid properties. Unlike pressure loss correlations, fluid correlation settings cannot be entered individually in the Well editor.

To define your fluid correlations:

1. Click the **Properties** menu and select **Correlations**.

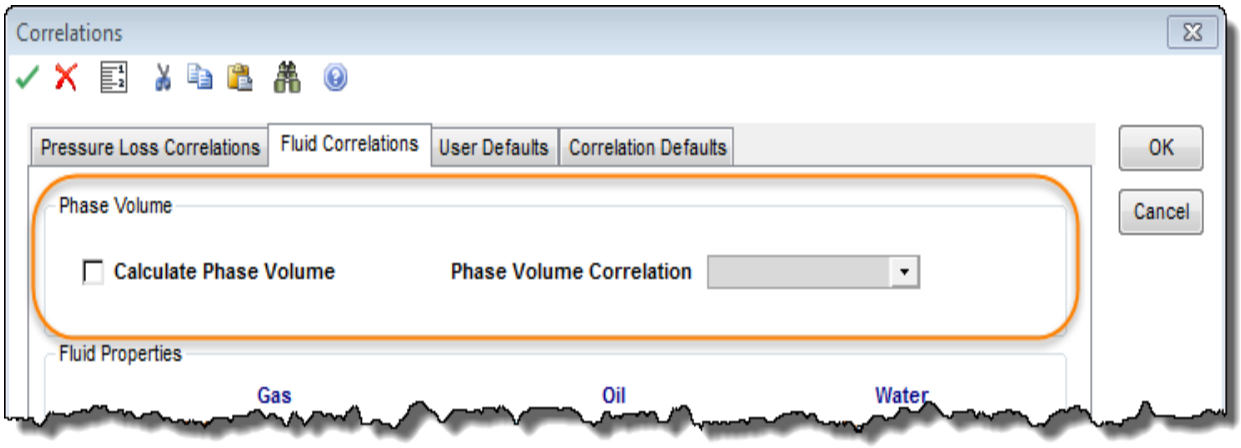
   The Correlations dialog box opens.

2. Click the **Fluid Correlations** tab.

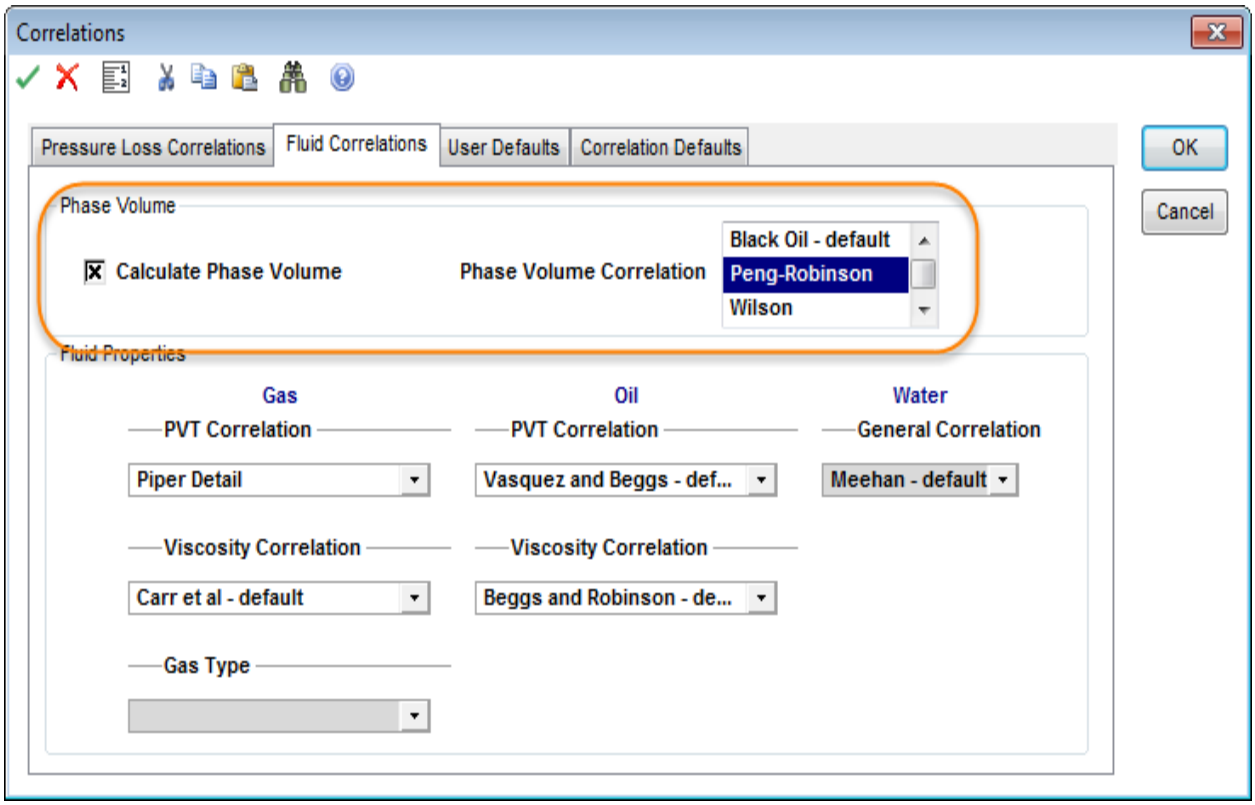


3. To calculate hydrocarbon phase change, select the **Calculate Phase Volume** checkbox.

   Select phase volume calculations for oil, or liquids-rich gas condensate systems.



4. If you selected Calculate Phase Volume in step 3, select a **Phase Volume Correlation**. Otherwise, continue to step 5.



The following data must be entered based on your selected phase volume correlation. This data can be entered in either the Defaults or Well editors, or both the Defaults and Well editors.

Phase Volume Correlation	Required Data
Black Oil	▪ **Gas** - gas gravity

Phase Volume Correlation	Required Data
	or C1 -C7+ detail composition ■ CO_2 / H_2S / N_2 concentrations ■ **Oil**- API gravity ■ **Water** - water specific gravity
Peng-Robinson or Wilson	■ C1 - C7+ detail composition ■ CO_2 / H_2S / N_2 concentrations ■ C7+ MW ■ C7+ specific gravity

Data entered in the Defaults editor is applied globally to all wells. Data entered in the Well editor applies to each individual well. For further information on entering well fluid data, see well fluid properties.

For further information on phase volume correlations, see phase volume correlations.

5. Select the **Gas PVT Correlation**.

The Gas PVT Correlation field is selectable based on the Phase Volume Correlation selected in step 4, and requires additional data to be entered as follows:

Correlation		Data for selected Gas PVT Correlation	
Phase Volume Correlation	**Gas PVT Correlation**	**Benedict-Webb Rubin (B.W.R.) (Table), B.W.R. (8-constant), B.W.R. (11-constant)**	**Piper Detail**
No Phase Volume Correlation (i.e., not calculating phase volume)	can be selected	Required- gas gravity	Required - C1 - C7+ detail composition.
Black Oil	can be selected	Required- gas gravity	n / a
Wilson	can be selected	■ Required- gas gravity	■ Required -C1 - C7+ detail composition.

Correlation		Data for selected Gas PVT Correlation	
Phase Volume Correlation	**Gas PVT Correlation**	**Benedict-Webb Rubin (B.W.R.) (Table), B.W.R. (8-constant), B.W.R. (11-constant)**	**Piper Detail**
		■ Required -C1 - C7+ detail composition. ■ C7+ MW ■ C7+ specific gravity	■ C7+ MW ■ C7+ specific gravity
Peng-Robinson	not selectable, properties are a direct output of Peng-Robinson	■ Required -C1 - C7+ detail composition. ■ C7+ MW ■ C7+ specific gravity	■ Required -C1 - C7+ detail composition. ■ C7+ MW ■ C7+ specific gravity

If it exists, optional data that can be entered for all phase volume / gas PVT correlation combinations includes: H_2S, N_2, and CO_2 volume percent impurities. For more information, see gas PVT correlations.

6. Select the **Gas Viscosity Correlation**.

   No additional data entries are required for gas viscosity correlation options.

   For more information, see gas viscosity correlations.

7. Select a **Gas Type**:

   - **Dry** gas — for dry gas. This option corresponds to the miscellaneous gases curve in gas PVT correlations.
   - **Wet** gas — select this option for most gas wells. This option corresponds to the condensate well fluids curve in gas PVT correlations.

   Note: Gas Type is only available if you are not calculating phase volume. It requires no additional data entry.

8. Select your **Oil PVT correlation** and **Oil Viscosity Correlation**.

   The Oil PVT and Viscosity Correlation fields are selectable based on the Phase Volume Correlation selected in step 4, and require additional data to be entered as follows:

Correlation			
Phase Volume Correlation	**Oil PVT Correlation**	**Oil Viscosity Correlation**	**Required Data**
No Phase Volume Correlation (i.e., not calculating phase volume)	can be selected	can be selected	API gravity.
Black Oil	can be selected	can be selected	API gravity.
Peng-Robinson	not selectable, default is Peng-Robinsson	not selectable, default is Lorenz, Bray and Clark	■ C1 - C7+ detail composition ■ C7+ MW ■ C7+ specific gravity
Wilson	can be selected	not selectable, default is Lorenz, Bray and Clark	■ C1 - C7+ detail composition ■ C7+ MW ■ C7+ specific gravity

For more information, see oil PVT correlations and oil viscosity correlations.

Only one PVT correlation for water exists and therefore it is automatically selected. The only data entry required is water specific gravity. Optionally, salinity can be entered in terms of parts per million.

9. Click **OK**.

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Defining compositions

A well's composition is defined through:

- global defaults
- well fluid properties

Global defaults

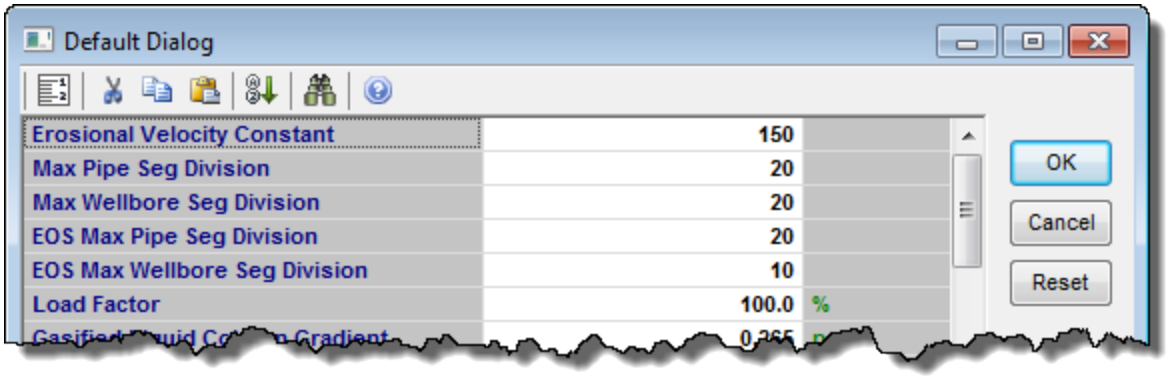
The Default dialog box is populated with a set of default gas, oil, and water properties. Simple fluid properties for wells, and complex fluid properties are entered in this editor. These defaults are applied to all wells automatically, although each well can have unique fluid properties. For further information on setting these properties for individual wells, see well fluid properties.

Simple composition

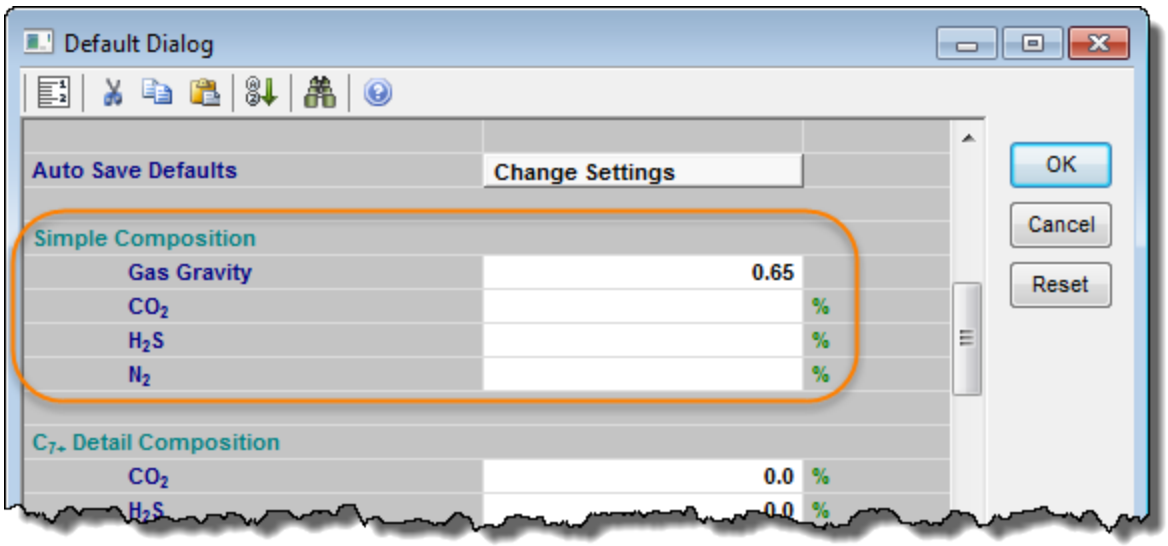
To define simple composition for wells:

1. Click the **Properties** menu and select **Defaults**.

   The Default dialog box opens.



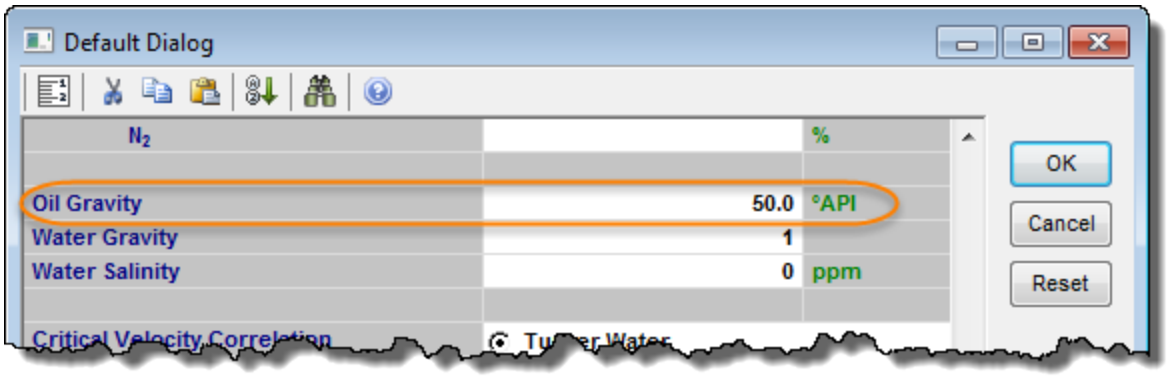
2. Scroll down to the **Simple Composition** section.



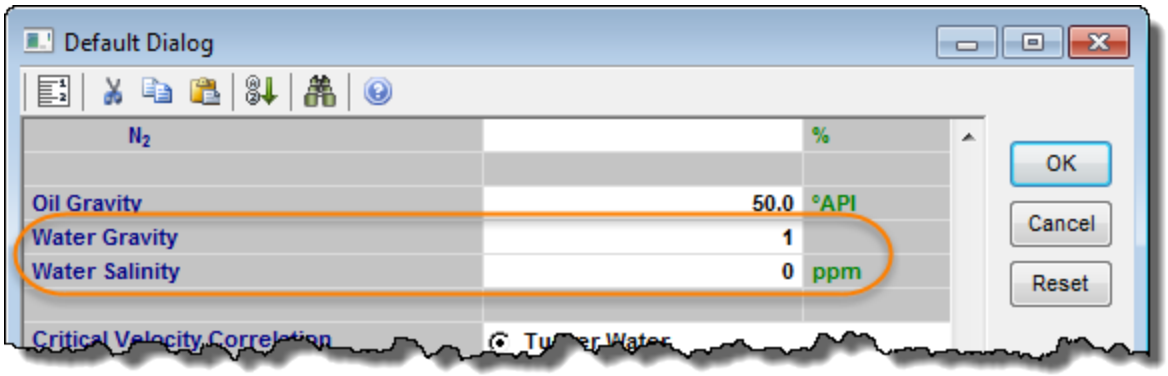
3. Enter your default gas gravity (G).
4. Enter the concentrations for CO_2, H_2S, and N_2.impurities.

   If you do not enter these values, they are set to zero.

5. Scroll down to the section marked Oil Gravity.



6. Enter your **Oil Gravity** in degrees API.
7. Enter your **Water Gravity** and **Water Salinity**.



8. Click **OK**.

Detailed composition

The detailed composition (complex fluid properties) is used if you selected Phase Volume Calculation or Piper Detail PVT correlation for your fluid correlations.

To define a default composition:

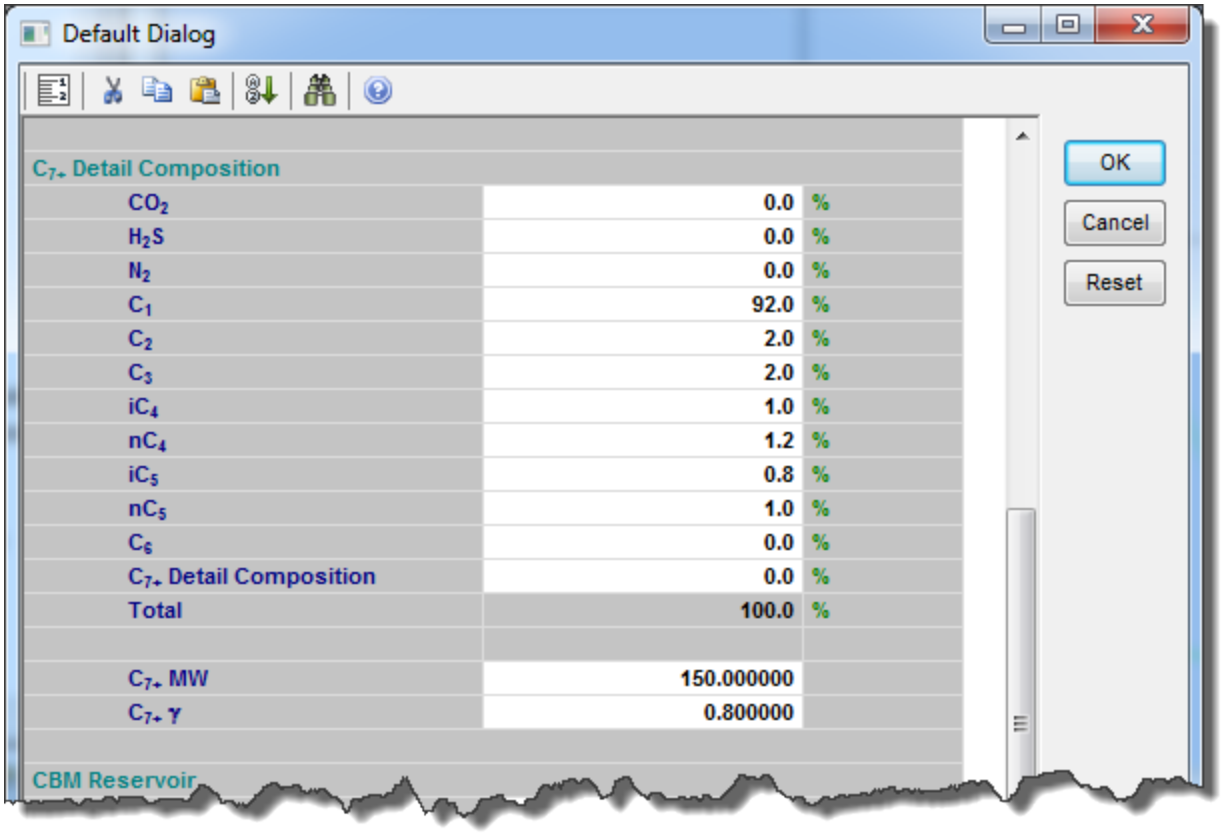
1. Click the **Properties** menu and select **Defaults**.

The Default dialog box opens.

2. Scroll down to the **C7+ Detail Composition** section.

3. Enter your values for each component.

   The Piper Detail Gas PVT Correlation does not require C7+ MW, nor C7+ γ.



4. Click **OK**.

Well fluid properties

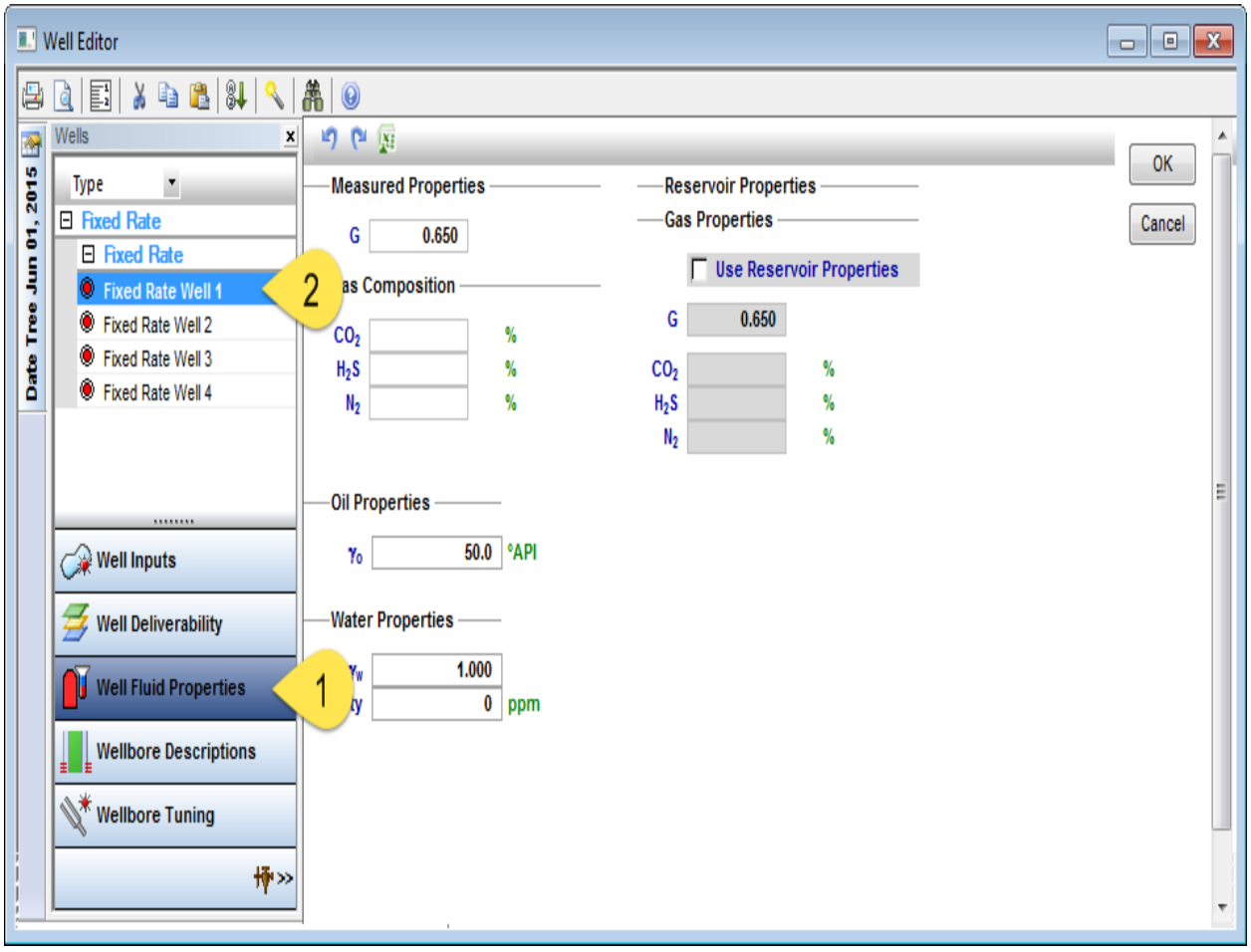
Wells can have unique fluid properties, however all wells must have the same fluid correlation. For information on setting your fluid correlations, see defining fluid correlations. To apply the same fluid properties to all your wells, we recommend using global defaults.

Note: If you have RTA wells, individual fluid properties are automatically set on import.

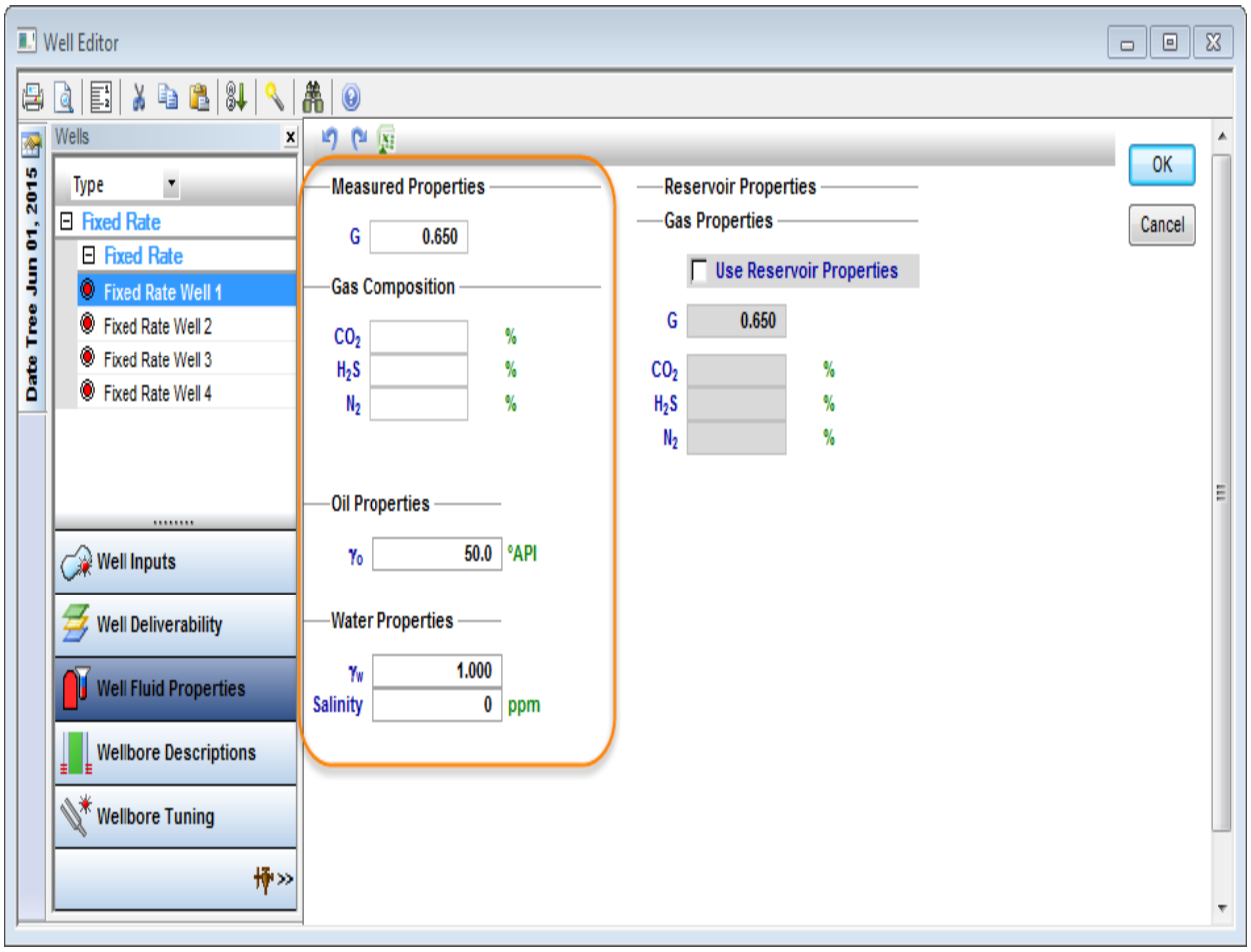
To enter fluid properties for an individual well:

1. Click the **Wells** menu and select **Well Editor**.
2. Click **Well Fluid Properties**, and select a well.

   Depending on the fluid correlations you have selected, the properties displayed in the well fluid properties pane varies.

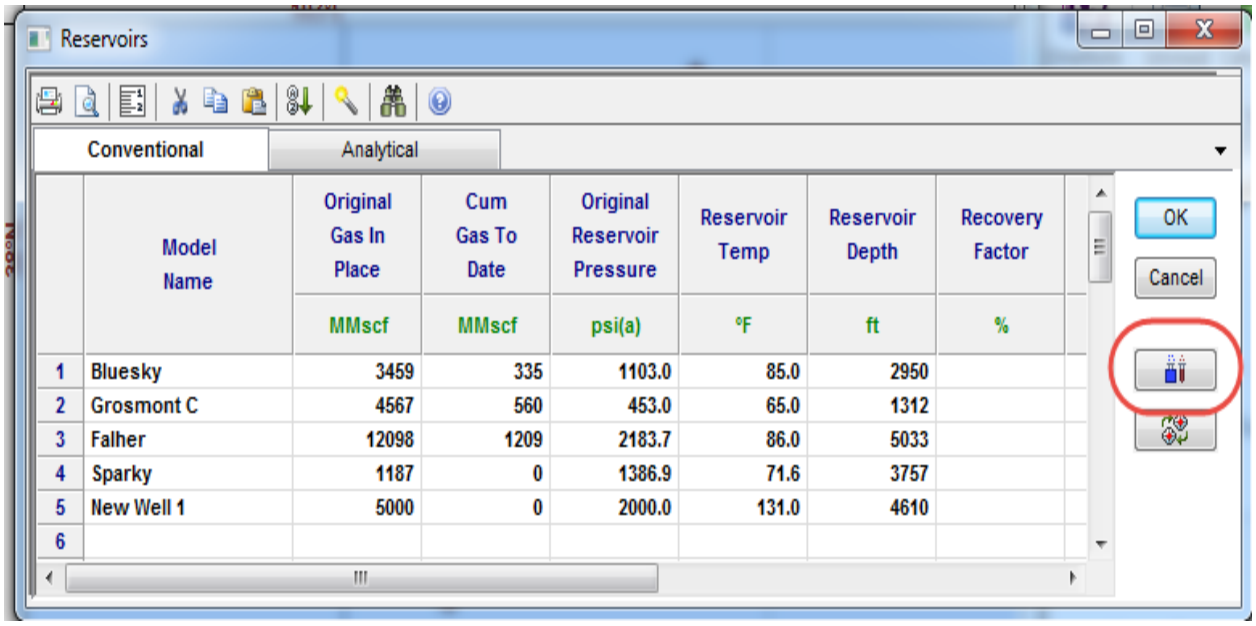


3. Set your properties in the **Measured Properties** column.



4. Click **OK**.

5. If your system contains wells that are attached to conventional gas reservoirs, click the **Reservoir** menu, and select **Reservoirs**. Then, click the **Gas Compositions** icon.

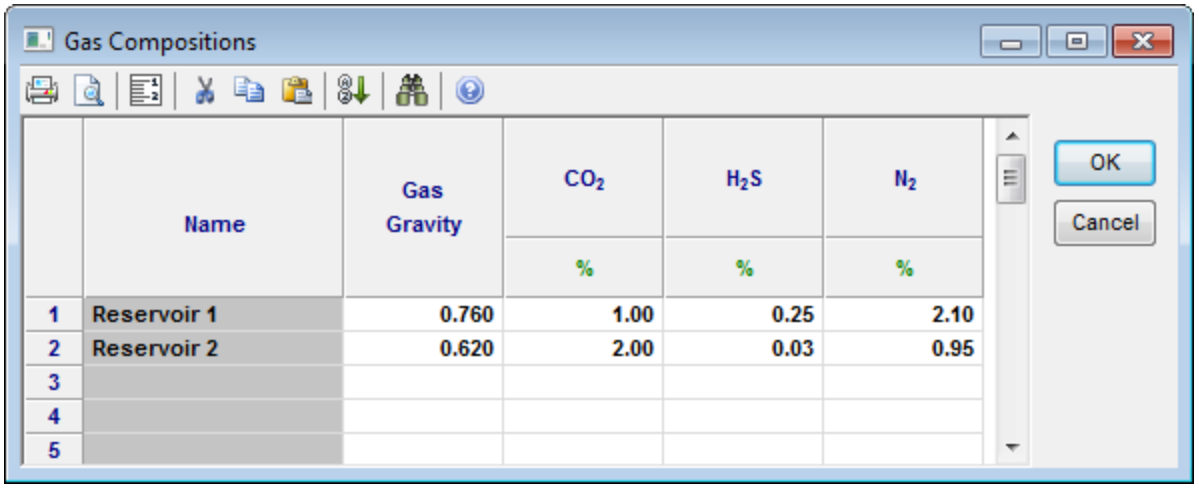


	Model Name	Original Gas In Place	Cum Gas To Date	Original Reservoir Pressure	Reservoir Temp	Reservoir Depth	Recovery Factor
		MMscf	MMscf	psi(a)	°F	ft	%
1	Bluesky	3459	335	1103.0	85.0	2950	
2	Grosmont C	4567	560	453.0	65.0	1312	
3	Falher	12098	1209	2183.7	86.0	5033	
4	Sparky	1187	0	1386.9	71.6	3757	
5	New Well 1	5000	0	2000.0	131.0	4610	
6							

All wells connected to the same reservoir can use the same fluid properties.

Note: Oil and water properties must be set on a well-by-well basis, and cannot be set for a reservoir.

6. Enter your reservoir gas properties: **Gas Gravity**, **CO_2**, **H_2S**, and **N_2**.

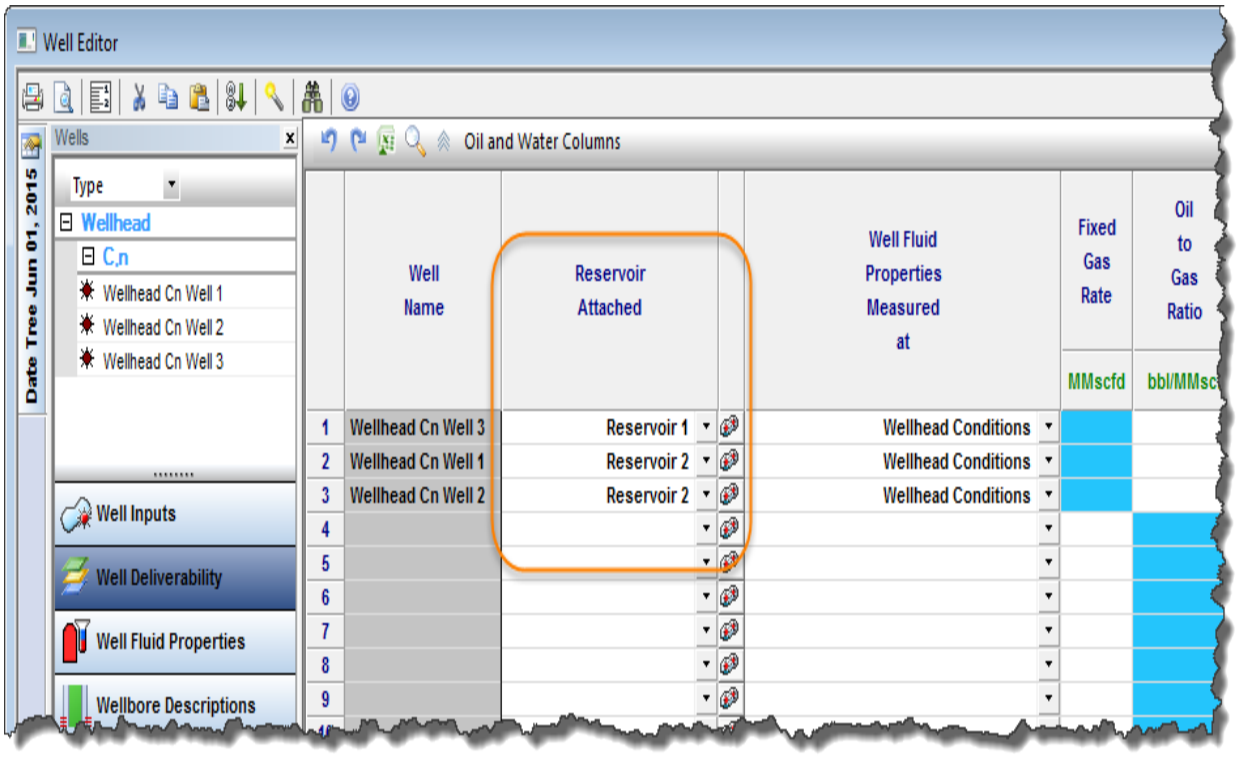


	Name	Gas Gravity	CO_2	H_2S	N_2
			%	%	%
1	Reservoir 1	0.760	1.00	0.25	2.10
2	Reservoir 2	0.620	2.00	0.03	0.95
3					
4					
5					

7. Click **OK**.

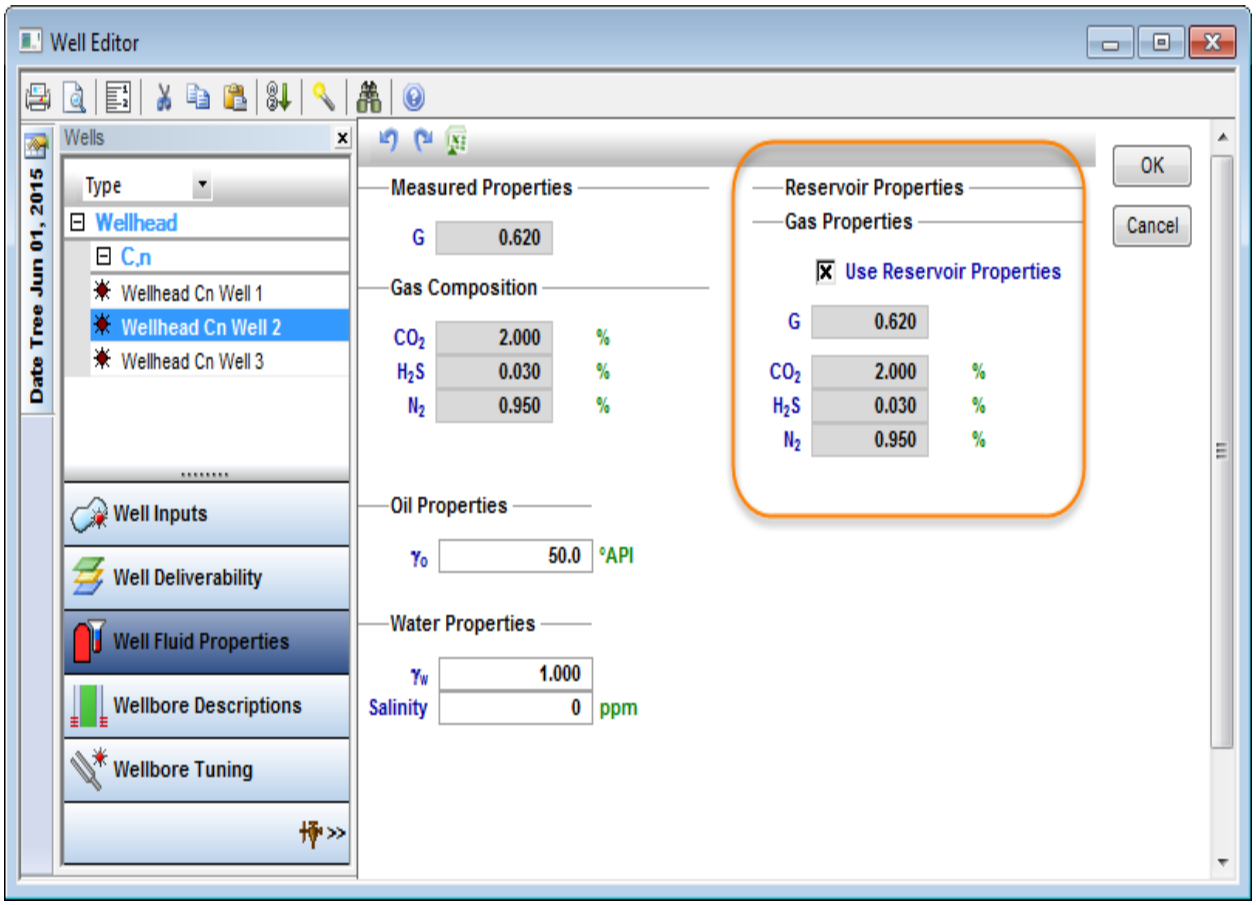
8. Click the **Wells** menu and select **Well Editor**.

9. Click **Well Deliverability**, and for each well attached to a conventional reservoir, select a reservoir from the **Reservoir** drop-down list in the Reservoir Attached column.



10. Click **Well Fluid Properties** and select **Use Reservoir Properties**.

    The values you entered for reservoir gas compositions in step 6 are automatically populated.


Well Editor
Wells
Type
Wellhead
C,n
Wellhead Cn Well 1
Wellhead Cn Well 2
Wellhead Cn Well 3
Date Tree Jun 01, 2015
Well Inputs
Well Deliverability
Well Fluid Properties
Wellbore Descriptions
Wellbore Tuning
Measured Properties
G 0.620
Gas Composition
CO2 2.000 %
H2S 0.030 %
N2 0.950 %
Oil Properties
γo 50.0 °API
Water Properties
γw 1.000
Salinity 0 ppm
Reservoir Properties
Gas Properties
Use Reservoir Properties
G 0.620
CO2 2.000 %
H2S 0.030 %
N2 0.950 %
OK
Cancel

11. Click **OK**.

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Calibrating your model (the surface network)

It is important to make sure that data entered in your model represents operating conditions. The measured production data required for calibration includes: gas rates, liquid rates, wellhead pressure, line pressures, compressor or pump inlet and outlet pressures and rates, pipeline temperatures, and fluid analysis. We recommend using production data that was obtained from a point-in-time when field production was stable.

To calibrate your model:

1. To enter well fluid rates and pressures, click the **Import** menu and select **Production Import (Text, Excel)**. For more information on importing current production, see importing production data.

   Alternatively, you can import a Harmony Enterprise file (.hmy2pip). For more information, see importing data from Harmony Enterprise.

2. Click the **Present Forecast** icon ().

   Forecast results are displayed in the status window.

3. View the facility annotations, and confirm the accuracy of pressures and rates flowing to the compressors and pumps in your model. For more information on annotations, see annotations.

4. Use the pipeline pressure loss diagnostic map to identify where differences between measured data and calculated results exist.

Forecasting gathering systems

Forecasting is used to plan for future development, or to determine when optimization is necessary in your system. In Piper, a delivery facility is required for any system where fluid flows from a reservoir. The delivery facility is used as the sales / fluid destination point. The system may also contain other facility types. Each additional facility type that is included is intended to limit system performance within the range that is, or will be physically available. The following sections discuss models used to forecast gas or oil production:

- gas
- oil

Also see:

- profile
- wellhead deliverability
- sandface deliverability
- CBM
- RTA

Gas

There are multiple ways to account for changing gas production over time. The table below shows the available deliverability types and a summary of when to use each.

Tip: For information on how to add each type, click the hyperlink in the Deliverability Type column.

Deliverability Type	Deliverability model type
Profile	■ to account for 3rd party production ■ with limited or poor reservoir data ■ rate is not sensitive to changes in pressure ■ not concerned with wellbore effects
Wellhead Test	■ calculate the C value using current wellhead producing rates and reservoir conditions ■ not concerned with wellbore effects ■ does not model transient reservoir inflow
Wellhead Deliverability	■ C and n values from pressure transient analysis available ■ not concerned with wellbore effects ■ does not model transient reservoir inflow
Sandface Deliverability	■ C and n values from pressure transient analysis available, or calculate C using current rate and pressure conditions ■ does not model transient reservoir inflow ■ to approximate when liquid loading may occur in the well-bore
RTA	■ models transient inflow affects associated with production from low permeability reservoirs ■ account for wellbore effects including submersible pump flow or gas lift

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Oil

You can forecast oil gathering systems by using fixed rate or profile wells, or by importing or manually adding oil analytical models. With fixed rate and profile wells, you can specify production rates that do not change when pressure changes. If you do not have reservoir data, or your reservoir data is not reliable, we recommend forecasting oil systems using profile wells. When you import oil analytical models, the models are sensitive to changes in pressure, and therefore are responsive to changes in field operating conditions.

Adding fixed rate wells

If you are using fixed rate wells in your gathering system, you must enter the fixed oil rate in Wells > Well Deliverability. This rate is then used for the forecast duration.

Note: For more information on adding fixed rate wells to your model, see editing the map, or converting nodes to facilities. You can also add a fixed rate well with the Well editor. For more information, see well inputs.

Adding a profile to a profile well

To add a profile to a profile well:

Note: You must have profile wells in your model before assigning a profile to a well.

1. For each profile well, select a **Profile** from the drop-down list in the Profile Name column.

   For information on how to create profiles, see profile.

2. Click **Well Inputs** and make sure the Onstream Date for each well is set.

3. Click **OK**.

   The profile data can now be used when you run a forecast.

Oil analytical models

Importing or adding oil analytical models

For information on importing or manually adding analytical models, see RTA.

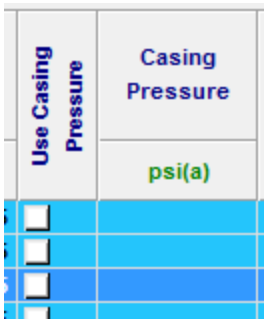
Modeling wellbores

Free-flowing oil wells can flow up the tubing or the annulus in the same way they do for gas wells. Either single-phase liquid or multiphase pressure loss correlations can be selected for the wellbore. Oil wells on artificial lift have two options: pumping or gas lift.

Pumping

The pumping option assumes that there is a submersible pump at the end of tubing. The liquids flow up the tubing segment, while the gas flows up the annulus. Pressure loss is calculated along the casing pressure side. This can be done using one of two methods:

1. Specify the casing pressure:
    a. Click the **Wells** menu and select **Well Editor**.
    b. Click the **Wellbore Descriptions**.
    c. Select **Use Casing Pressure** and set the **Casing Pressure**.
    d. Click **OK**.



2. Or, deselect **Use Casing Pressure** if it is selected. The wellhead pressure is calculated from the downstream gathering system. This option means that pressure is dictated by the tubing side (where oil is flowing), which is incorrect in most cases. Therefore, we recommend that you also do the following :
    a. Click the **Facilities** menu and select **Separators**.
    b. Set **Inlet Pressure Determined From** to **Gas Outlet**.
    c. Click **OK**.

    This forces the separator to use the gas inlet pressure to determine the wellhead pressure used for wellbore calculations.

Gas lift

Gas lift modeling is always assumed to be injected at the end of tubing. There are two methods available for determining the gas volume injected, gas lift profile, or critical gas rate.

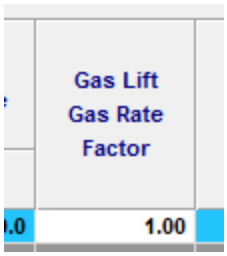
To select your gas lift injection method:

1. Click the **Wells** menu and select **Well Editor**.
2. Click **Wellbore Descriptions**.
3. Select **Use Gas Lift Profile** to use the gas lift profile method and then select a profile from the **Gas Lift Profile** drop-down list.

   For more information on setting profiles, see profile.

   Or, to use critical rate, select either **Turner** or **Coleman** for the **Liquid Lift Correlation**. Either water or condensate can be used to calculate the critical gas rate. If Not Considered is selected, no gas lift volume is added.

   To adjust the gas lift gas rate from the critical rate, specify a **Gas Lift Gas Rate Factor**. This factor is multiplied by the critical rate to determine the gas volume injected at end of tubing.



4. Click **OK**.

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Profile

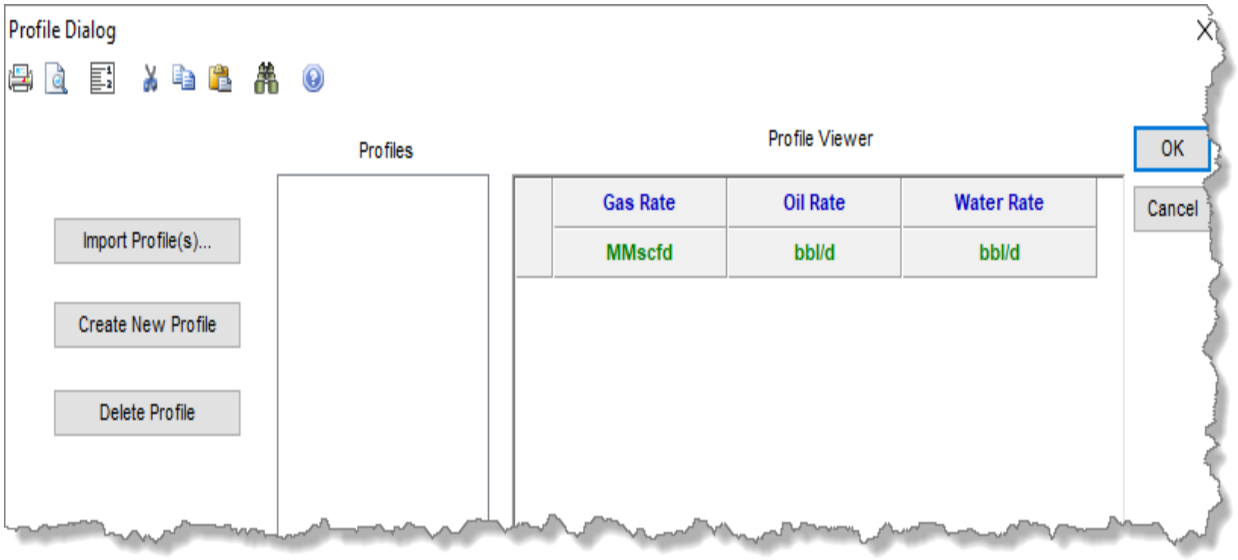
Profiles are used when you want to import or manually enter gas or fluid rates. Profiles are accessed through the profile icons in various editors. To enter a profile to forecast total flow from the well-head through the pipeline, use the well deliverability editor. To account for gas lift production volumes at the end of tubing through the production network, use the wellbore descriptions or the wellbore tuning editors.

Note: You must be in one of the editors listed above to create a profile.

To create a profile:

1. Click the **Profile** icon ( ) in one of the editors listed above.

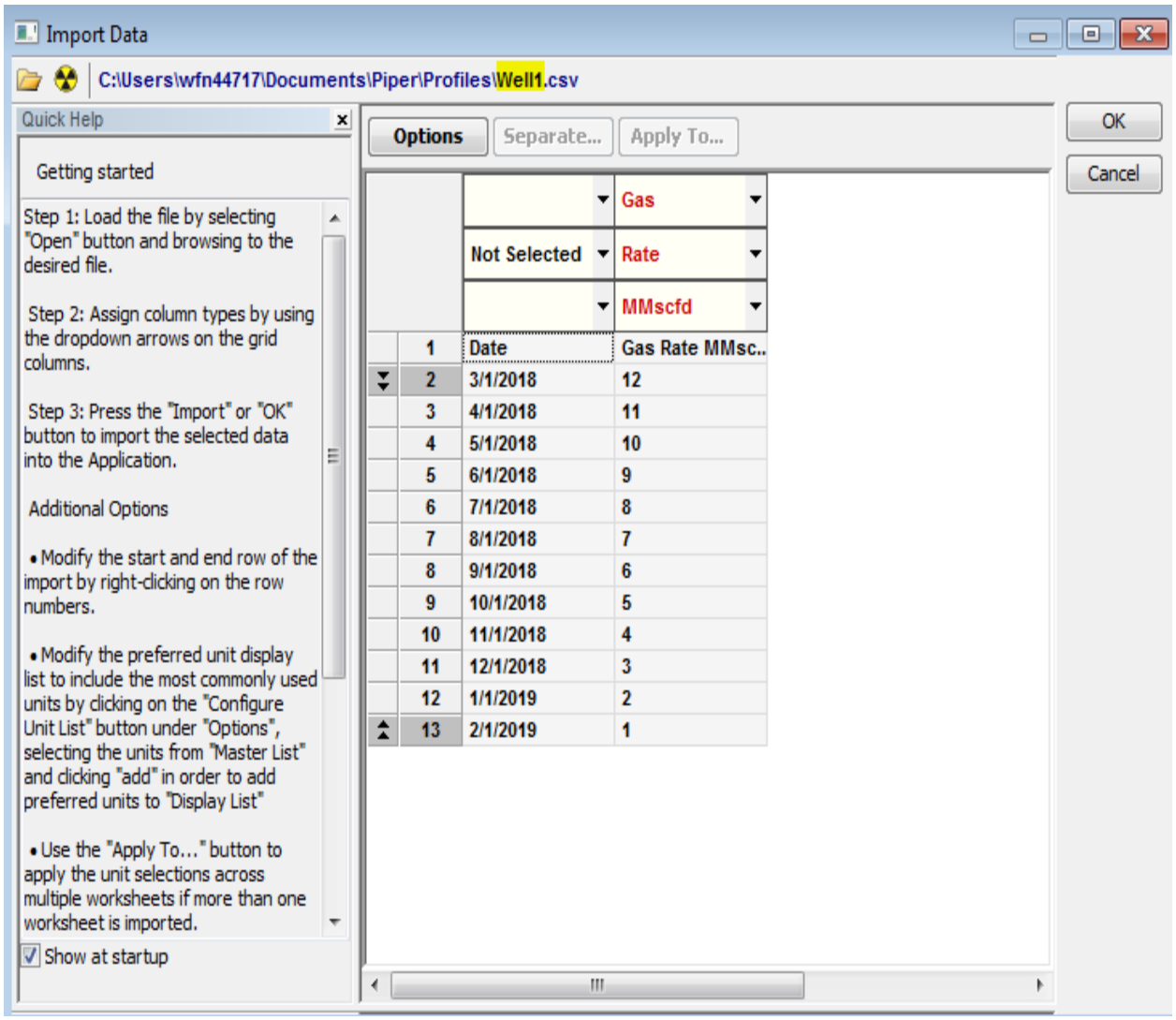
   The Profile dialog box opens.



2. Click **Import New Profile** to import an existing profile.

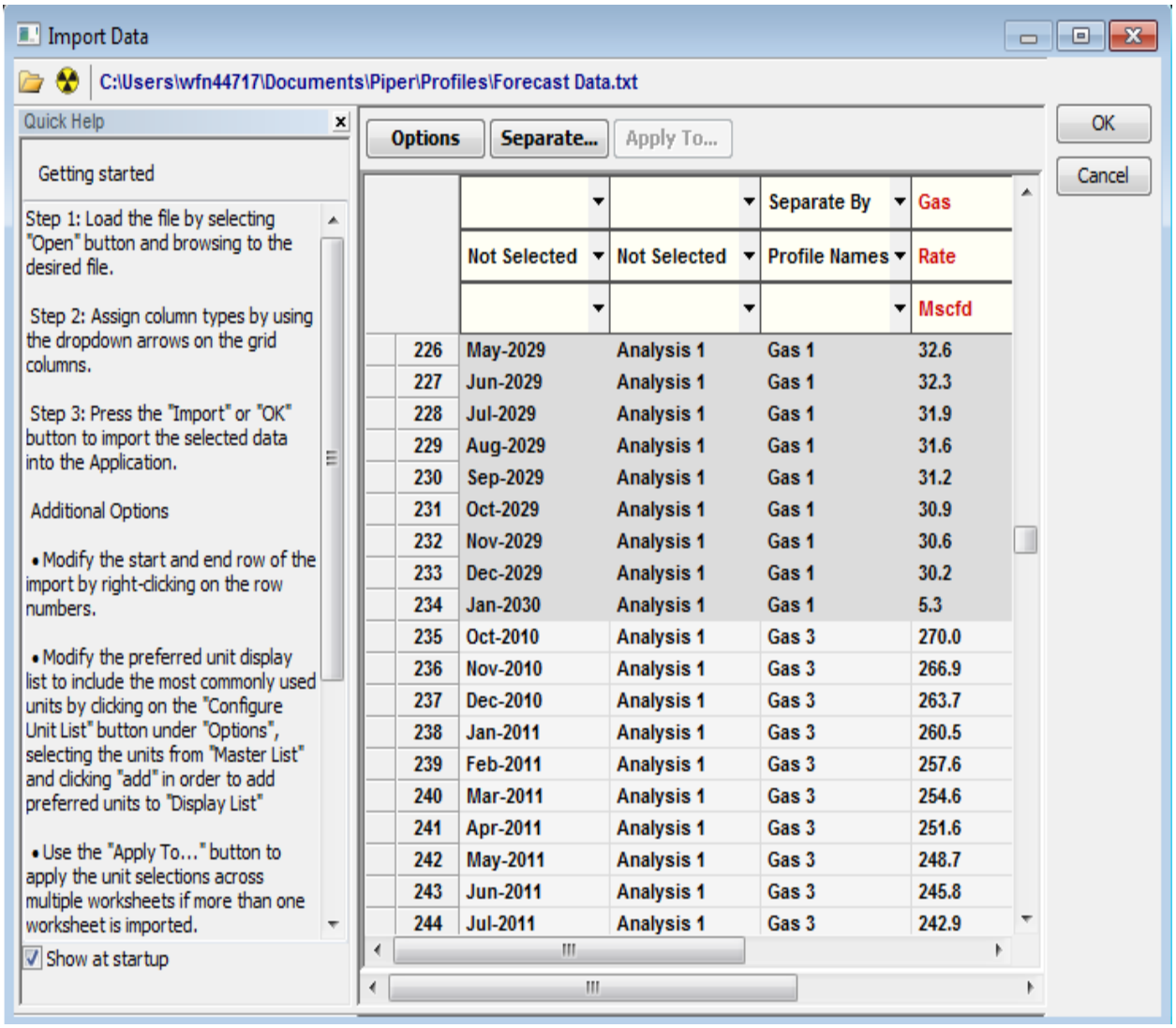
   The Import Data dialog box opens. Note that you can import .csv, .txt, and .xlsx files.

   Single profiles can be imported, and you can select the fluid and unit type for columns. (The file name is used to set the profile name.)

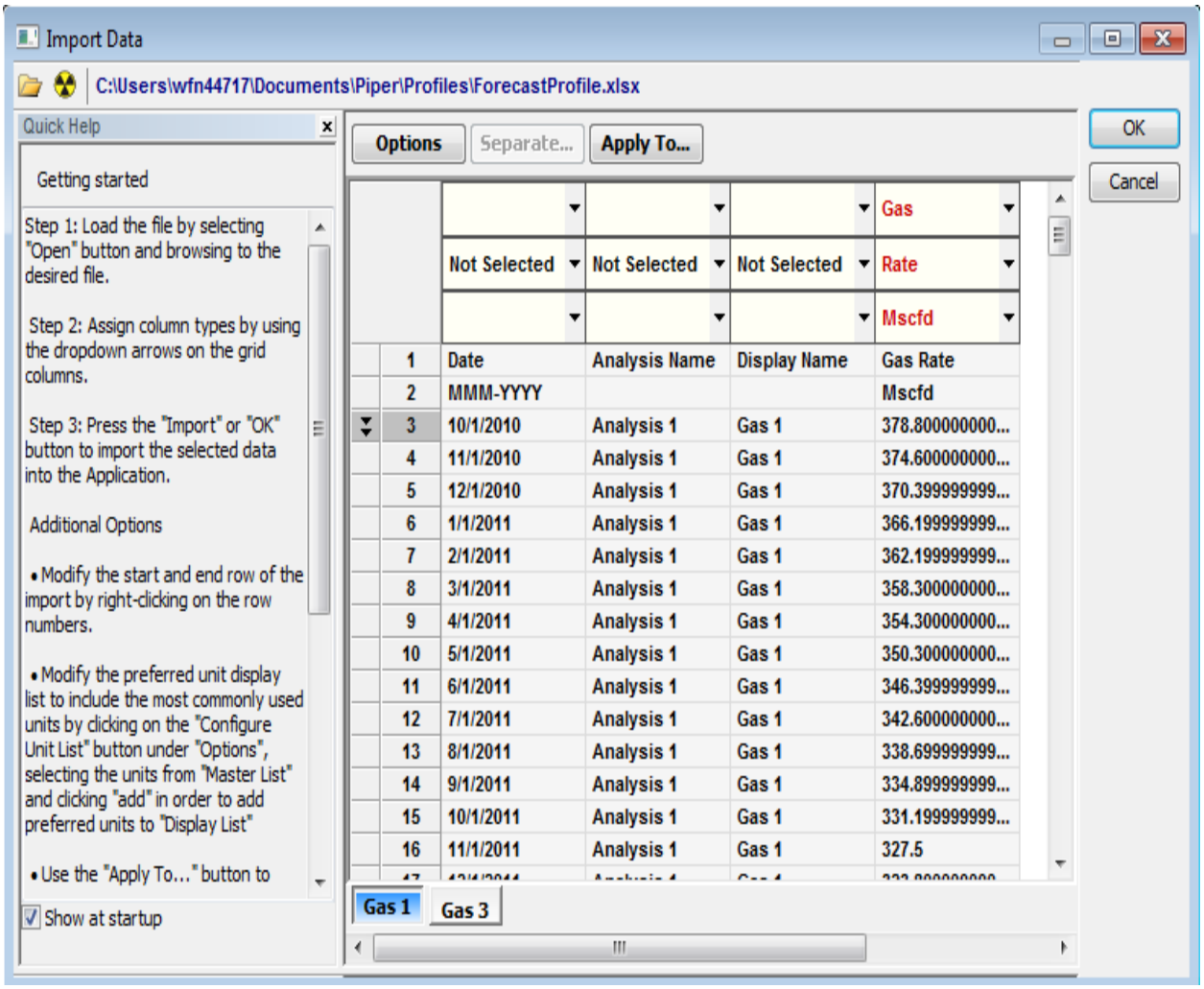


Multiple profiles can also be imported from a single file in one of two formats.

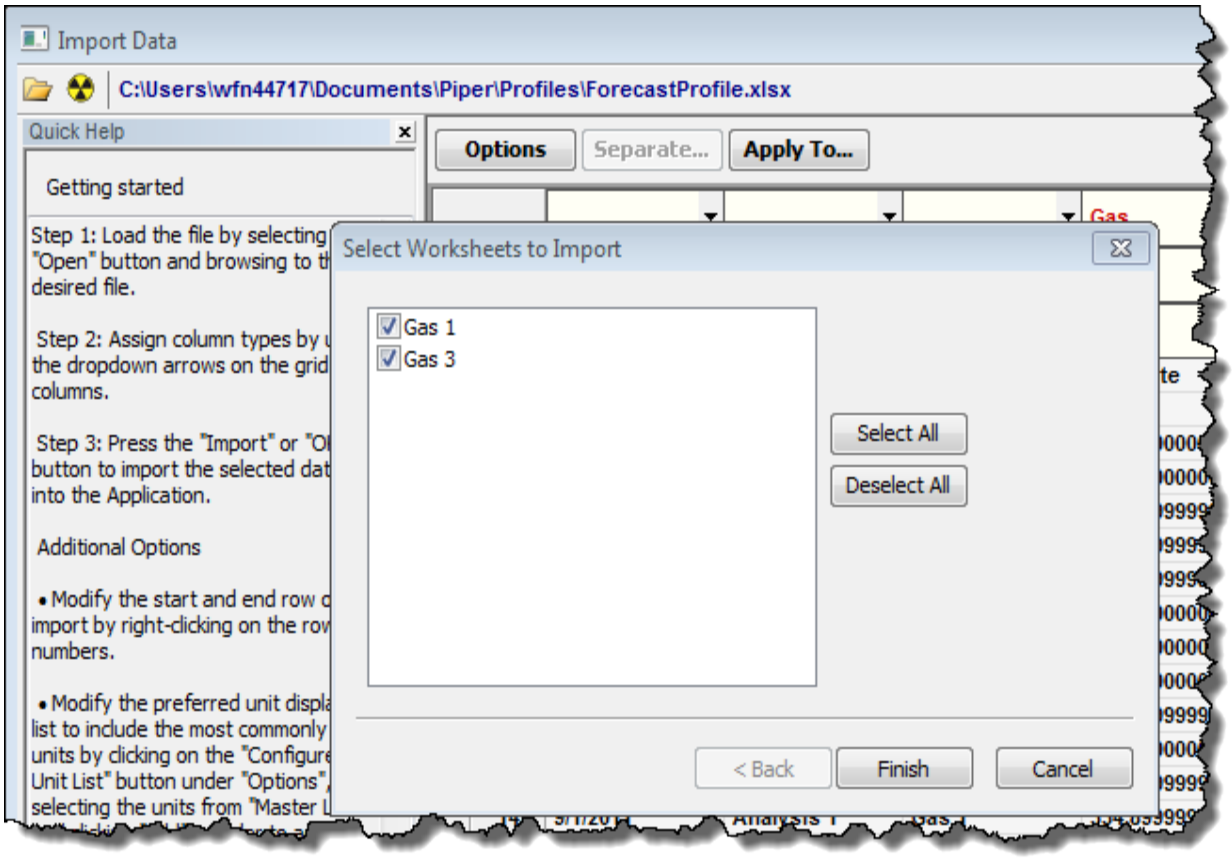
i.) You can select a profile name (included in the data) for one of your columns by selecting the **Separate By** option.



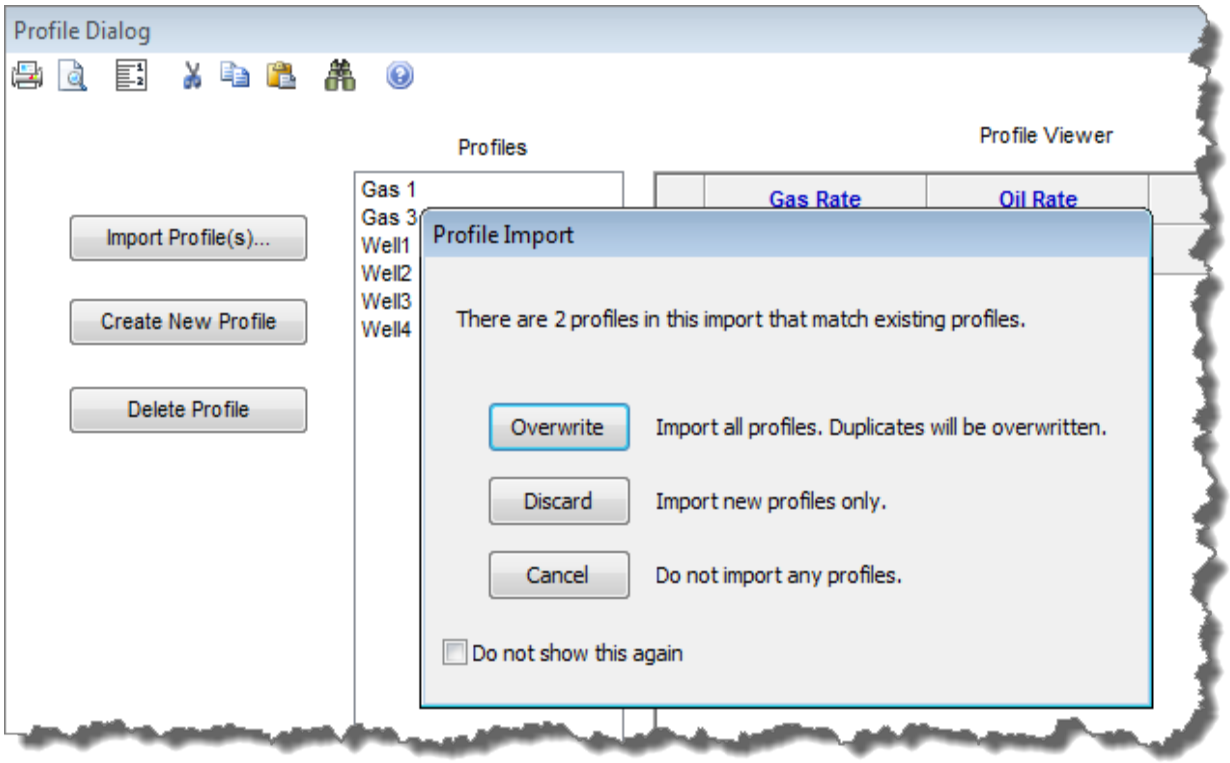
ii.) You can also separate profiles in tabs with an Excel file. If the format is identical in all tabs, you can click the **Apply To** button to apply the format once, and it is copied to all tabs.



When multiple profiles are mapped, you can confirm your selections prior to importing the file by clicking the **Finish** button.



When the profile name exactly matches an existing profile, you are given an option to over-write the existing profile, or discard the imported one. (You can set your default behavior for importing profiles by clicking the **Properties** menu and selecting **Customize**, **Recent File Options**.)



Or, click **Create New Profile** and:

a. Enter a **Profile Name** in the Profile Name Editor dialog box.

When creating profiles for profile wells, profiles are typically associated with a well grouping which can be used as the profile name. However, if each well maintains a separate profile, enter the name of the selected well as set in the Well Name column.

b. Click **OK**.

c. Enter expected gas, oil and water rates as applicable.

- When creating profiles for profile wells, enter rates for each period of your forecast duration in the **Profile Viewer** grid. Rates are based on monthly or daily averages.
- When creating profiles for gas lift, profiles are defined on a period basis. For example, to define the gas lift volumes for 12 months, 12 period volumes need to be defined for the profile.

The Profile Viewer grid is populated with the imported or entered rates.

3. Click **OK**.

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Wellhead deliverability

To forecast changes in gas inflow with changes in pressure, the pressure squared methodology is used. Wellhead Test and Wellhead C,n use the same mathematical relationship; however selection of Wellhead Test, or Wellhead C,n is dependent on available data. If you have representative inflow data from a pressure transient analysis (PTA), select Wellhead C,n; if you only have stabilized inflow rates, select Wellhead Test. This methodology must only be used for gas wells that have reached boundary-dominated flow, and when you do not need to account for production through the well-bore. For more information, see wellhead deliverability.

To use welhead deliverability:

Note: You must have Wellhead Test or Wellhead C, n wells in your model. For more information on adding these wells to your model, see editing the map, or converting nodes to facilities. You can also add these well through the well editor. For more information, see well inputs.

1. Click the **Wells** menu, select **Well Editor** and then click **Well Deliverability**.
2. Select a wellhead test or wellhead C, n well for the well type. Select a reservoir from the drop-down list in the **Reservoir Attached** column, and then click the **Reservoir** icon ().

   If you have not added a reservoir to your model, see reservoirs.

3. Enter all reservoir parameters except the recovery factor.

   These parameters are used to calculate the current and forecast reservoir pressure. The reservoir depth is used to convert between reservoir and surface static pressures.

4. Click the **Gas Compositions** icon () and enter the recombined reservoir properties (CO_2, H_2S, N_2). Click **OK** in the Gas Compositions and in the Reservoirs dialog boxes.

   Depending on your well selection, not all parameters are used in forecast calculations. For example, wellhead test wells do not use wellhead C, and wellhead C,n wells do not use wellhead flow rate and wellhead flow pressure.

	Well Name	Reservoir Attached		Oil to Gas Ratio	Water to Gas Ratio	WH Flow Rate	WH Flow Press	Well Head C	Well Head n
				bbl/MMscf	bbl/MMscf	MMscfd	psi(a)	MMscfd/(psi²)ⁿ	
1	200/D-055-K/094-H...	test							
2	200/D-057-K/094-H...	test							
3	200/B-059-K/094-H...	test							
4	200/D-066-K/094-H...	test							
5	200/D-068-K/094-H...	C,n							
6	200/D-077-K/094-H...	C,n							
7	200/B-079-K/094-H...	C,n							

5. Click **OK**.

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Sandface deliverability

To forecast changes in gas inflow with changes in pressure, the pressure-squared methodology is used. Sandface deliverability accounts for hydrostatic and frictional pressure losses of fluids within the wellbore; therefore, wellbore effects are accounted for in this deliverability model. This methodology must only be used for gas wells that have reached boundary-dominated flow. For more information, see sandface C, n deliverability.

To define your sandface C, n deliverability model, you can enter C,n data from a representative pressure transient analysis (PTA), or you can calculate the C value by entering wellhead flowing rates and pressures and assuming an n-value.

Sandface deliverability using PTA

To use data from a PTA:

Note: You must have Sandface C,n wells in your model. For more information on adding these well to your model, see editing the map,or converting nodes to facilities. You can also add these wells through the well editor. For more information, see well inputs.

1. Click the **Wells** menu, select **Well Editor**, and then click **Well Deliverability**.
2. Select a sandface C, n well. Select a reservoir from the drop-down list in the **Reservoir Attached** column, and then click the **Reservoir** icon ().

   If you have not added a reservoir to your model, see reservoirs.
3. Enter all reservoir parameters except the recovery factor.

   These parameters are used to calculate the current and future reservoir pressure.
4. Click the **Gas Compositions** icon () and enter the recombined reservoir properties (CO_2, H_2S, N_2). Click **OK** in the Gas Compositions and in the Reservoirs dialog boxes.
5. Enter **Sandface C**, and **Sandface n** data in the well deliverability pane.
6. Click **Wellbore Descriptions** and enter **Tubing ID**, **Tubing OD**, **Casing ID**, **EOT** (end of tubing), and **mpp** (mid-point-of-perforations depth).
7. If both gas and liquid are present in the well, select **Multiphase** and select a **Correlation** from the drop-down pressure loss correlation list.
8. Click **OK**.

Calculating a C value using the flowing side data

Sandface pressures are calculated using the selected pressure loss correlation, entered tubular data, and surface flowing rates and pressures. If you are operating within the liquid loaded region, we recommend calculating the C value using non-flowing pressure data.

To calculate a C value using flowing side data:

1. Repeat steps 1 to 7 in the section on using PTA, omitting step 5.
2. Click **Wellbore Tuning**.
3. Enter the **Rate**, **Tubing Pressure** or **Casing Pressure**, **n**-value, **Oil to Gas Ratio**, and / or **Water to Gas Ratio**.
4. Click **Sandface C** 

in the Calculate Sandface C column.

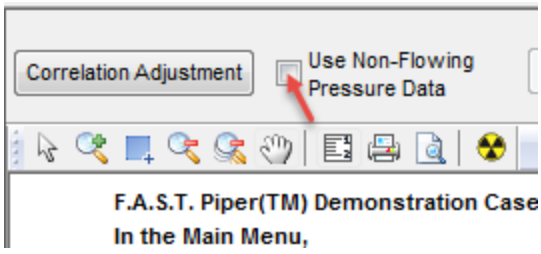
   For more information on this calculation, see wellbore sandface C calculation.
5. Review the Wellbore Tuning Plot to determine if the curve represents operating conditions. For more information, see wellbore tuning plots.
6. Click **OK**.

Calculating a C value using the non-flowing side pressure data

To remove unknowns (such as, liquid in the wellbore or liquid produced), the sandface C value is calculated through the non-flowing side pressure data. This assumes that there is only a gas column to the end of tubing; below that point a gasified-liquid gradient is used to calculate the pressure loss. The gasified-liquid gradient is set in the Defaults editor.

To calculate a C value using non-flowing side pressure data:

1. Repeat steps 1 to 7 in the section on using PTA, omitting step 5.
2. Click **Wellbore Tuning**.
3. Click **Use Non-Flowing Pressure Data**.



4. Enter the **Rate**, **Tubing Pressure** or **Casing Pressure**, **n**-value, **Oil to Gas Ratio**, and / or **Water to Gas Ratio**.

5. Select a **Liquid Lift Correlation** from the drop-down list.

   The liquid lift correlation is used to approximate the critical liquid lift rate at the end of tubing (EOT). If a combination of oil and water exists, select the water option. There is a difference between Turner and Coleman of approximately 20%; Turner predicts loading sooner. For more information on selection options, see Turner or Coleman.

6. Select **Add Delta P when segment loads** for Method Used When Well Loads.

   These selections are used to calculate the inflow rate once the well is operating in the critical liquid lift range.

   - **Add Delta P when segment loads** — adds a total pressure drop assuming the entire segment has loaded
   - **Percent Reduction** — used to account for inflow in plunger lift systems. For example, if the overall production is reduced by 10% due to down time of the plunger, enter in a 10% reduction
   - **Submersible pump** — assumes all liquid through the tubing, gas through the annulus, and the pump is landed at the EOT. A default fluid column of 250 ft is assumed to be above the EOT.

7. Click **Sandface C** 

in the Calculate Sandface C column.

   For more information on this calculation, see wellbore sandface C calculation.

8. To make sure you are not over-predicting the wells production capability, compare the calculated absolute open flow (AOF) to historical production.

9. Click **OK**.

CBM

Inflow capability for coalbed methane (CBM) or coal seam gas (CSG) wells is defined through production history-matching with Harmony. CBM capabilities will not be migrated to Harmony Enterprise, and CBM-to-Piper interoperability is not supported in Piper 2018.1 and later.

If CBM wells exist in your legacy Piper models, they will be converted to fixed rate wells when the file is opened in Piper 2018.1, and a backup of your starting file will be created in the event you wish to roll back.

If you plan to continue using CBM deliverability models within Piper, we recommend you use Piper 2016.1 or earlier. CBM-to-Piper interoperability support will be available until the end of your current S&P GlobalCBM software subscription or maintenance term.

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RTA

Rate transient analytical (RTA) models can forecast fluid inflow responses in low permeability oil and gas formations when operating conditions in a gathering system change. You can import analytical models, or add them manually through the software. Analytical model forecast calculations require detailed production history data in order to calculate superposition effects on current production. Without production history data, an analytical does will not forecast correctly. We recommend importing wells with existing production data from Harmony.

Importing analytical models

To import an analytical model, see importing Harmony files. When you import RTA models, you can select the following import types: vertical, fracture, horizontal, composite, general multifrac, multifrac composite, uniform multifrac, and enhanced fracture region.

Wells imported from RTA models are automatically added to the Unresolved and Resolved Wells tabs in the production plotting tab. For more information on resolving wells, see using production plotting.

Adding analytical models

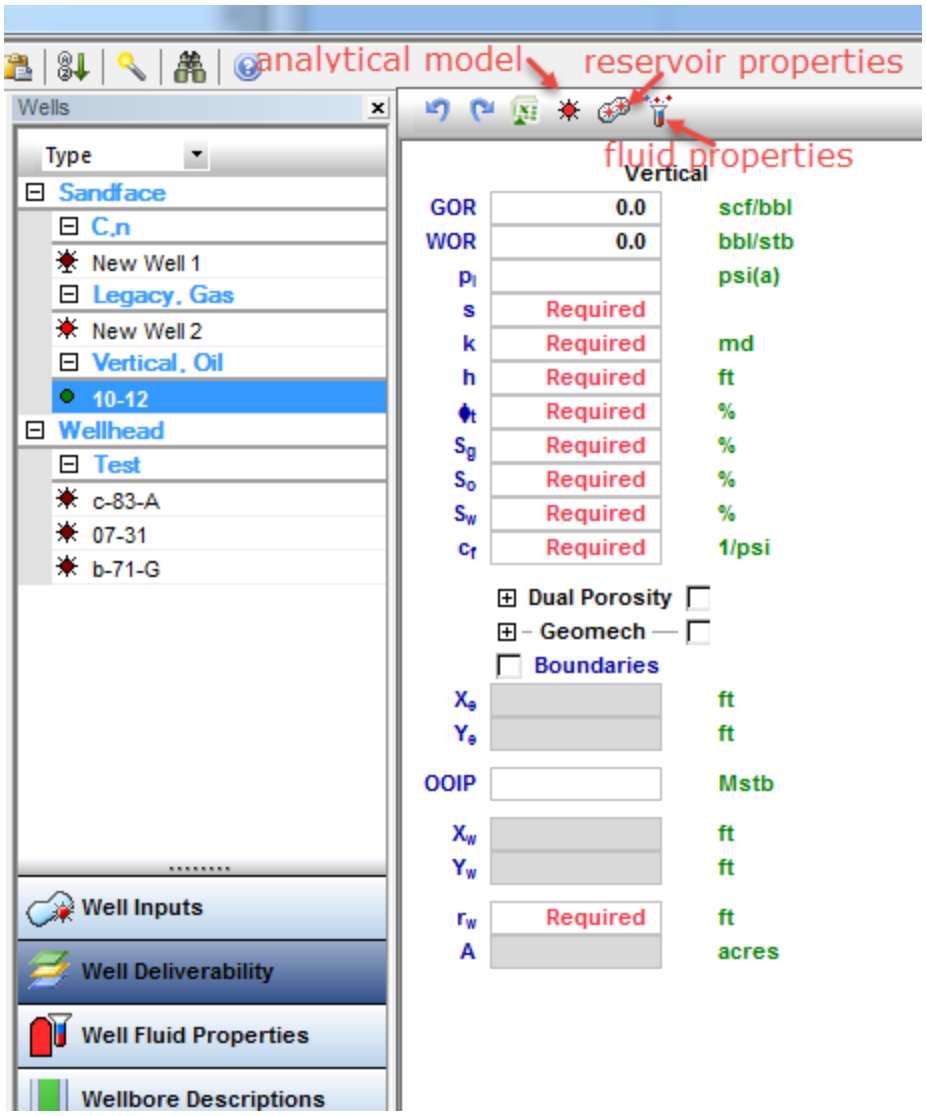
To add new analytical models (models with no previous production), click the **Well** icon () drop-down list and select **Analytical** > (**Oil or Gas**) and the applicable model type. For information on adding analytical wells to your model, see editing the map, or converting nodes to facilities. You can also add analytical wells through the well editor. For more information, see well inputs.

In order to run a forecast, the analytical model data must be fully populated in the Analytical Model, Reservoir Properties, and Fluid Properties tables.

To populate this data:

1. Click the **Wells** menu, select **Well Editor**, select the oil or gas analytical well you created, and then click **Well Deliverability**.

   The data tables are accessed through the icons displayed in the toolbar.



By default, the analytical model data table is displayed. Note that the data fields displayed vary depending on the model type you selected.

2. Enter the required data in each of the tables.

3. Enter the required wellbore information in the Wellbore Tuning editor. For more information on selecting gas lift, see modeling wellbores.

4. Click **OK**.

   You can now run your forecast.

Forecasting injection systems

By forecasting an injection system, you can determine the appropriate size of your surface infrastructure.

Note: This procedure assumes that the injection fluid comes from a central location, and is injected at multiple well locations in an existing gathering system.

To forecast an injection system:

1. Set a delivery point as the central fluid source (gas or water), and the known pressure source. If your gathering system model has no delivery facility, see editing the map for information on adding facilities to your model.
    a. Right-click the delivery point and select **Edit**.
    b. Set the **Delivery Pressure** and click **OK**.
2. To add central fluid source rates (gas or water), add a fixed-rate well or a profile well adjacent to the delivery point.

    If a pipeline already exists connecting the delivery point to the gathering system:

    a. Right-click the pipeline connected to the delivery point and select **Split Link**.

    For information on splitting links, see splitting links.

    b. Convert the node created from splitting the link to a Fixed Rate Well, or Profile Well. For information on converting nodes, see converting nodes to facilities.
    c. Set the gas or water rate:

    - For a fixed-rate well, right-click the well, select **Edit** and enter the Fixed Gas Rate or Fixed Water Rate.
    - For a profile well, see profile.

    All injection wells must use a negative rate for either fixed rate or profile wells. This negative value indicates that flow is away from the delivery point. For example, if the injection rate is 1 MMscfd per day, enter -1 in the gas rate MMscfd column.
3. If required, add a surface pump to the gathering system model.

    If there is additional pressure loss that prohibits flow (between the central fluid source and wells), surface pumps can be added to the pipeline links. If you are changing a node to a pump to add a pump to your model, make sure the node is connected to the pipeline prior to changing its type.

    You can now run your forecast.

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Validating forecasts

The process of validating forecasts makes sure that the data entered in your model is accurate and reflects the operating conditions in the field. After the forecast validation process is complete, the model can be used to test optimization scenarios to potentially increase deliverability and / or reduce cost in the gathering system.

The following features are used to validate production forecasts:

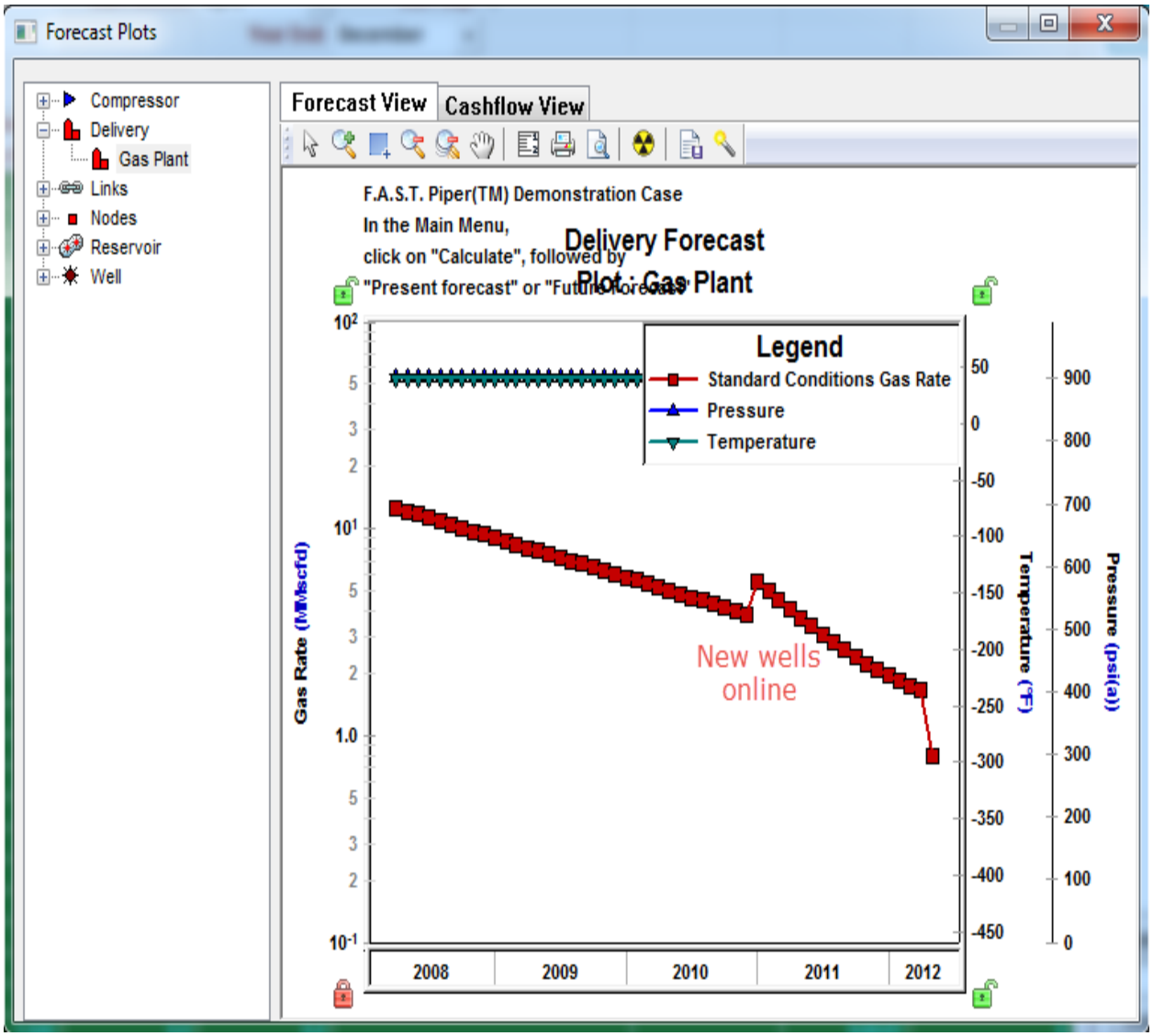
- forecast plots
- production plotting

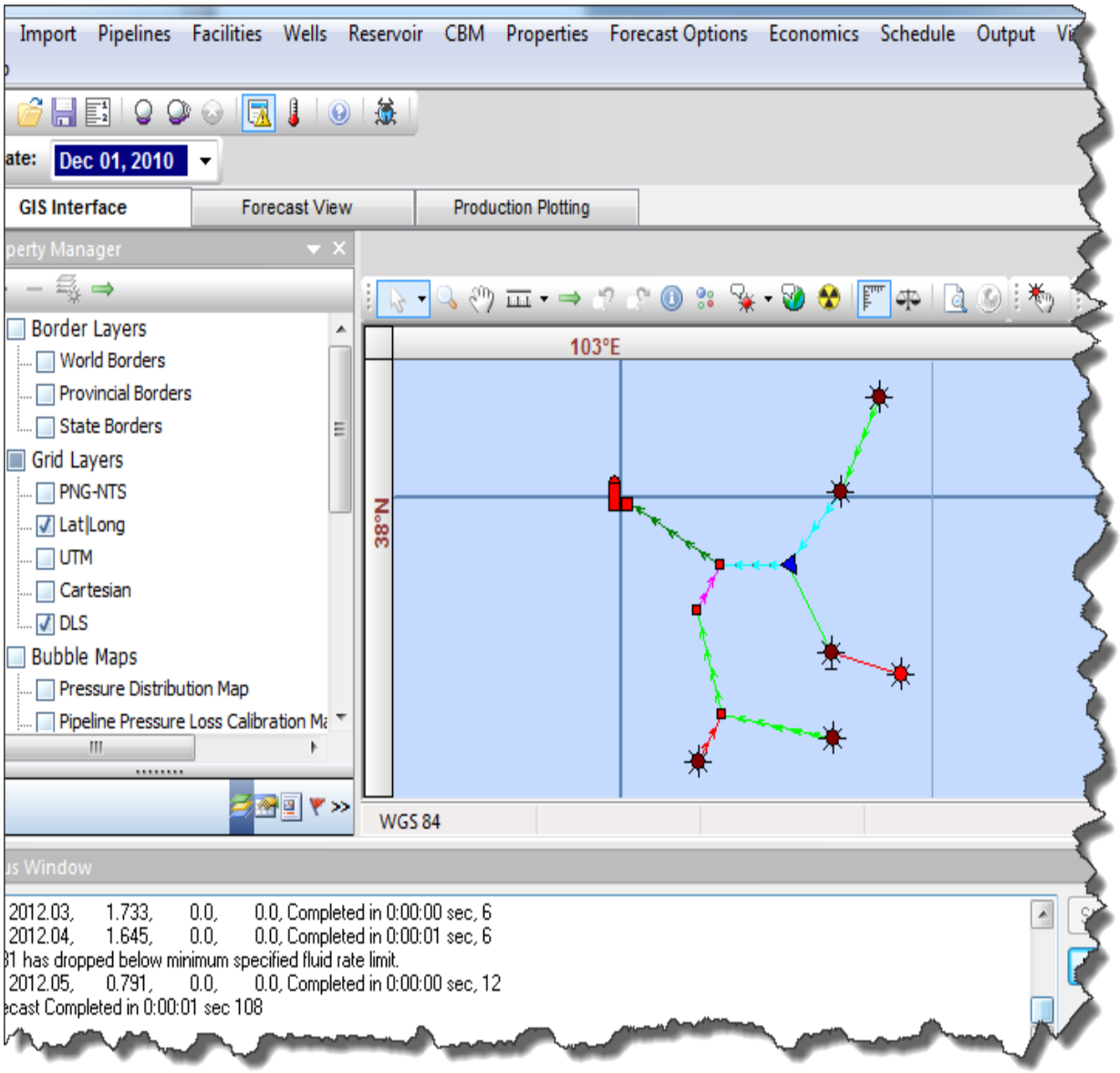
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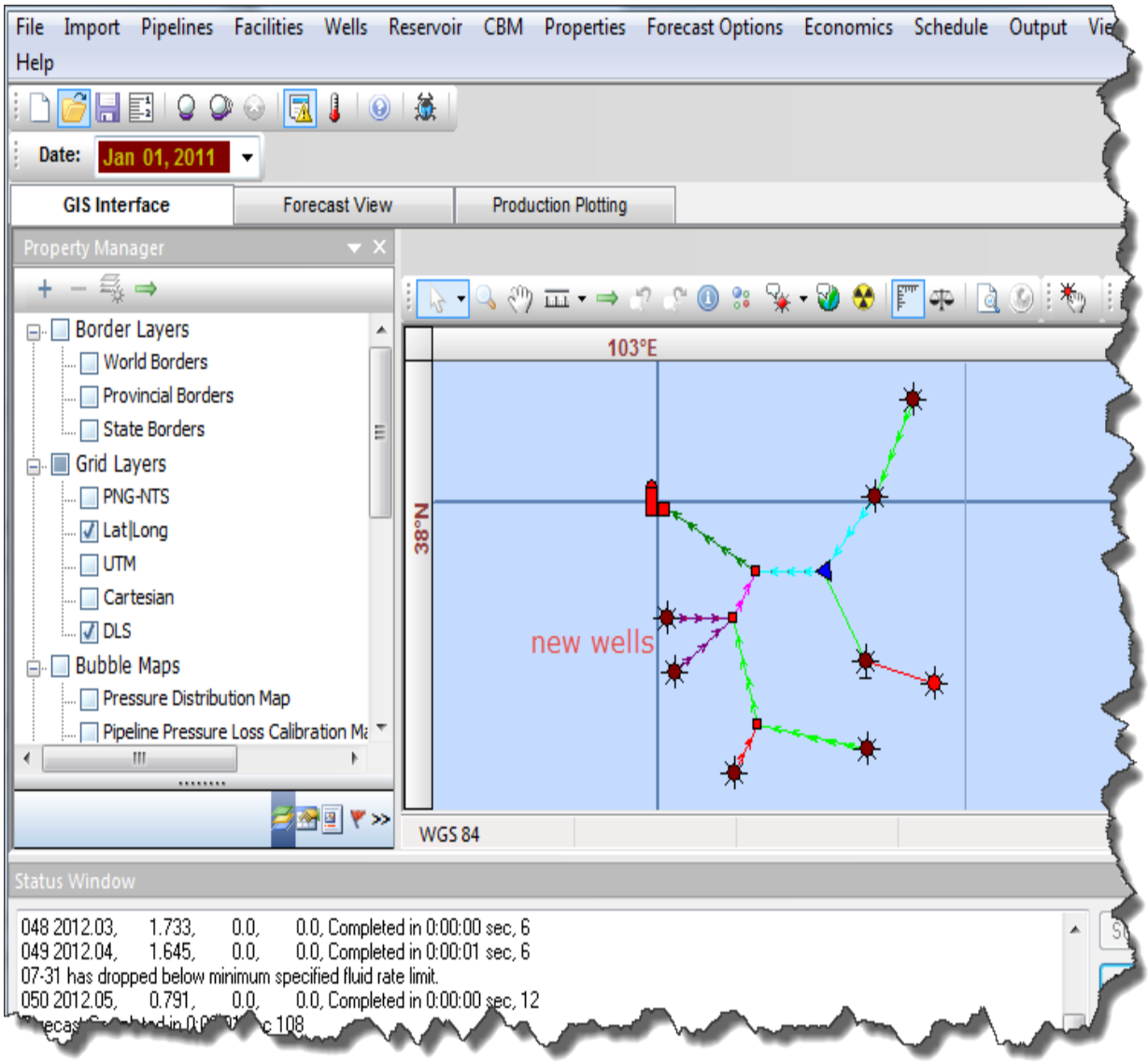
Forecast plots

Forecast plots are used to validate the data entered in your model. Forecast plots can be generated for all facilities in your gathering system to display rates and pressures over the forecast duration.

For example, in the screenshots below, the forecast view plot indicates an increase in gas rate in Jan 2011 at the delivery facility. By using the GIS interface and case controller, changes for Jan 2011 confirm that two new wells were brought online resulting in an increase in the gas rate. "Change dates" can also be viewed in the forecast view.




Import
Pipelines
Facilities
Wells
Reservoir
CBM
Properties
Forecast Options
Economics
Schedule
Output
ate:
Dec 01, 2010
GIS Interface
Forecast View
Production Plotting
perty Manager
Border Layers
World Borders
Provincial Borders
State Borders
Grid Layers
PNG-NTS
Lat|Long
UTM
Cartesian
DLS
Bubble Maps
Pressure Distribution Map
Pipeline Pressure Loss Calibration Ma
103°E
38°N
WGS 84
us Window
2012.03, 1.733, 0.0, 0.0, Completed in 0:00:00 sec, 6
2012.04, 1.645, 0.0, 0.0, Completed in 0:00:01 sec, 6
31 has dropped below minimum specified fluid rate limit.
2012.05, 0.791, 0.0, 0.0, Completed in 0:00:00 sec, 12
ecast Completed in 0:00:01 sec 108



Forecast plots for the other facility types can also be used to quickly identify and confirm the accuracy of rate and or pressure changes throughout the forecast duration.

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Production plotting

The Production Plotting tab provides a visual comparison of historical production data and your forecast data. The data is plotted in the Time and Cumulative tabs. For information on using production plotting, see using production plotting.

Production plots can identify if the forecast:

- matches historical trends
- does not match historical trends
- has gaps in production data

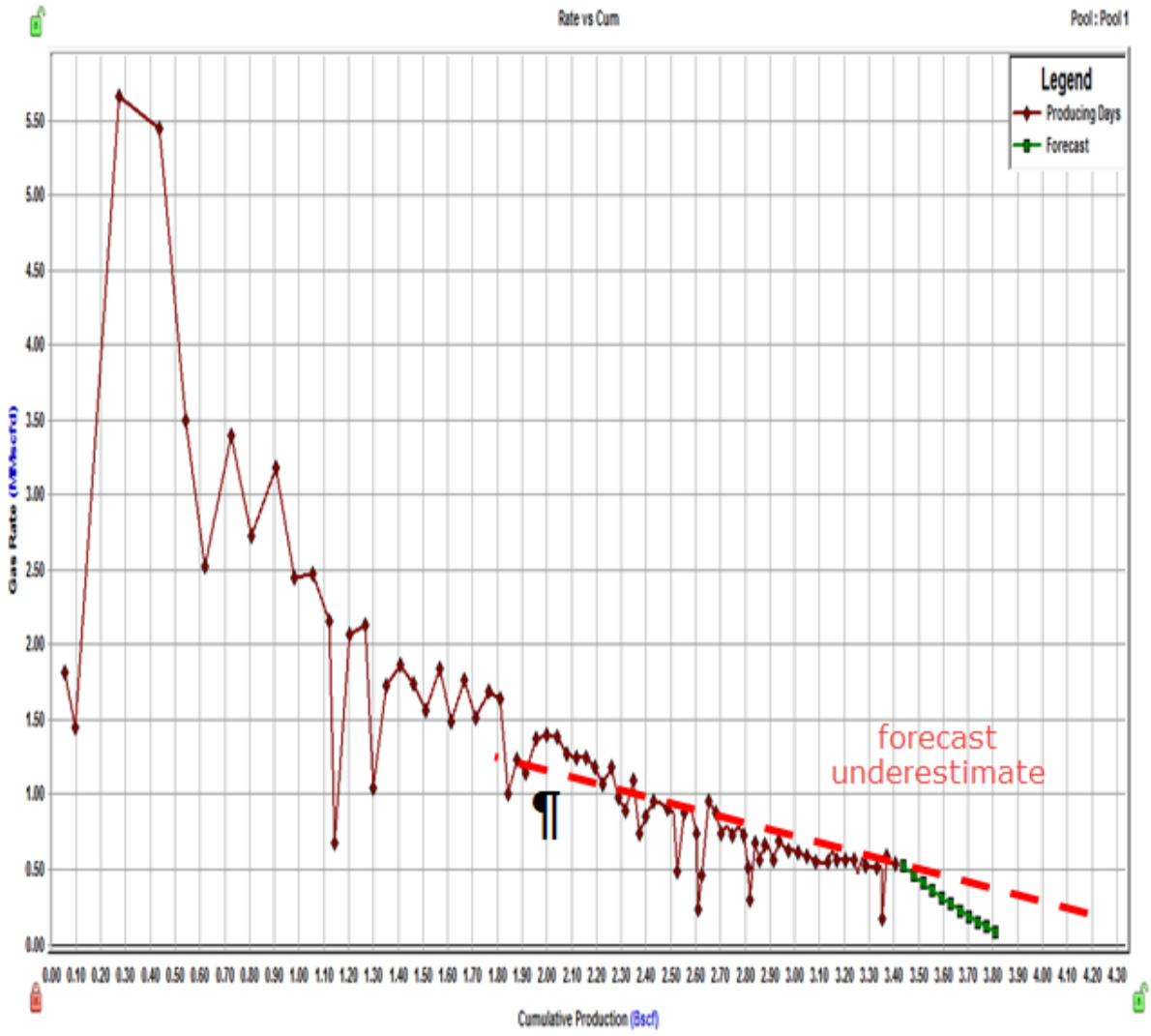
Forecast matches historical trends

When forecast data represents current field operating conditions, forecast production follows the same decline trend as historical production data. This continuous trend suggests that the reserves information entered into the model is representative of historical production. This check is called a production history match and is represented by the red line in the Rate vs. Time plot below.



Forecast does not match historical trends

If the production forecast over-estimates or under-estimates production reserves, or if the initial forecast rates do not match historical production, review the data provided for the reserves analysis.



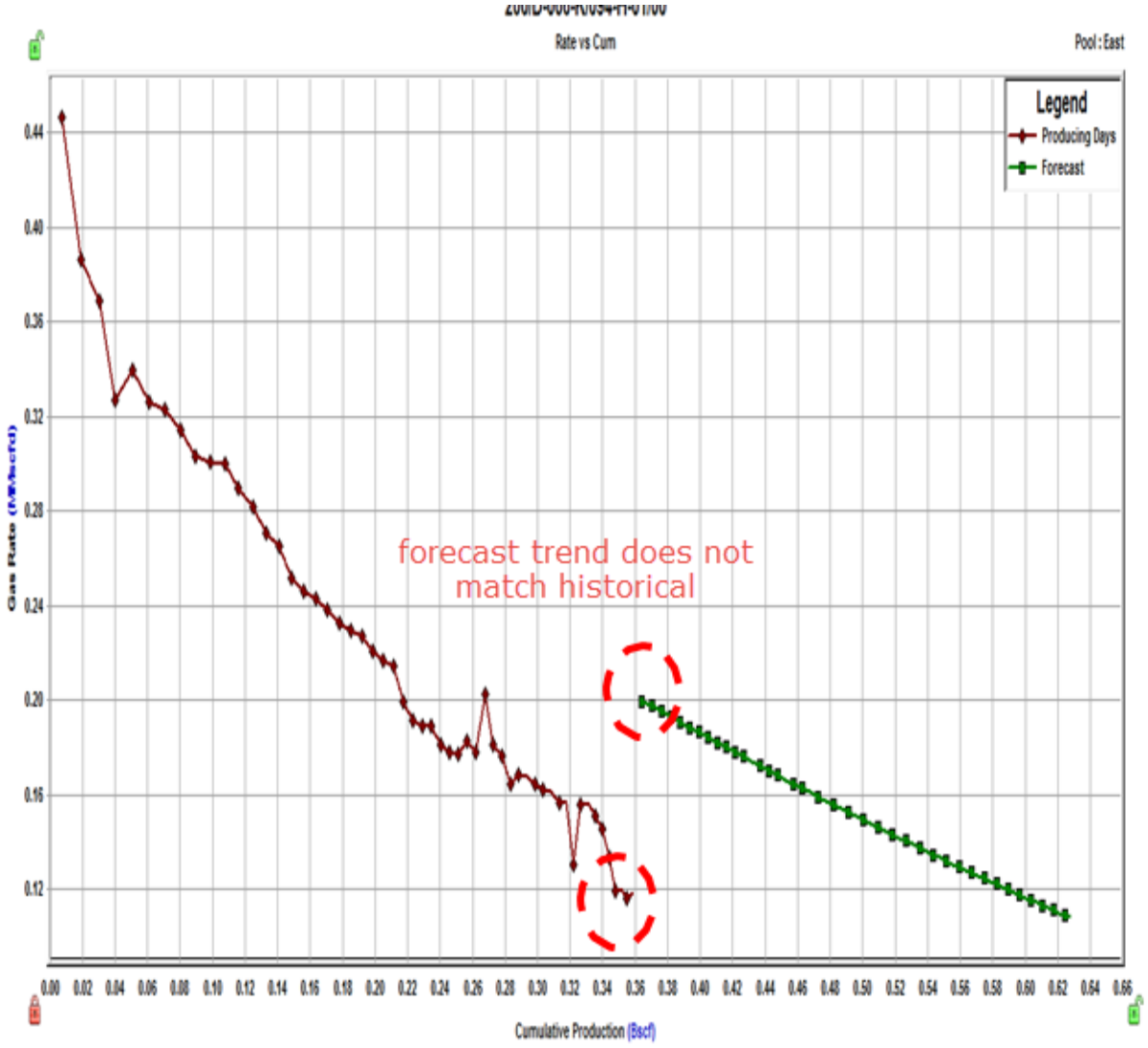
If the forecast has over-estimated or under-estimated historical data, make sure:

- the initial reservoir pressure has not been entered as the current reservoir pressure
- the OGIP or OOIP value has not been entered as the EUR
- investigate liquid loading — compare sandface and wellhead historical pressures to the ones used in the forecast

In some situations, the type of deliverability model selected results in a forecast that does not match historical production trends. This occurs when:

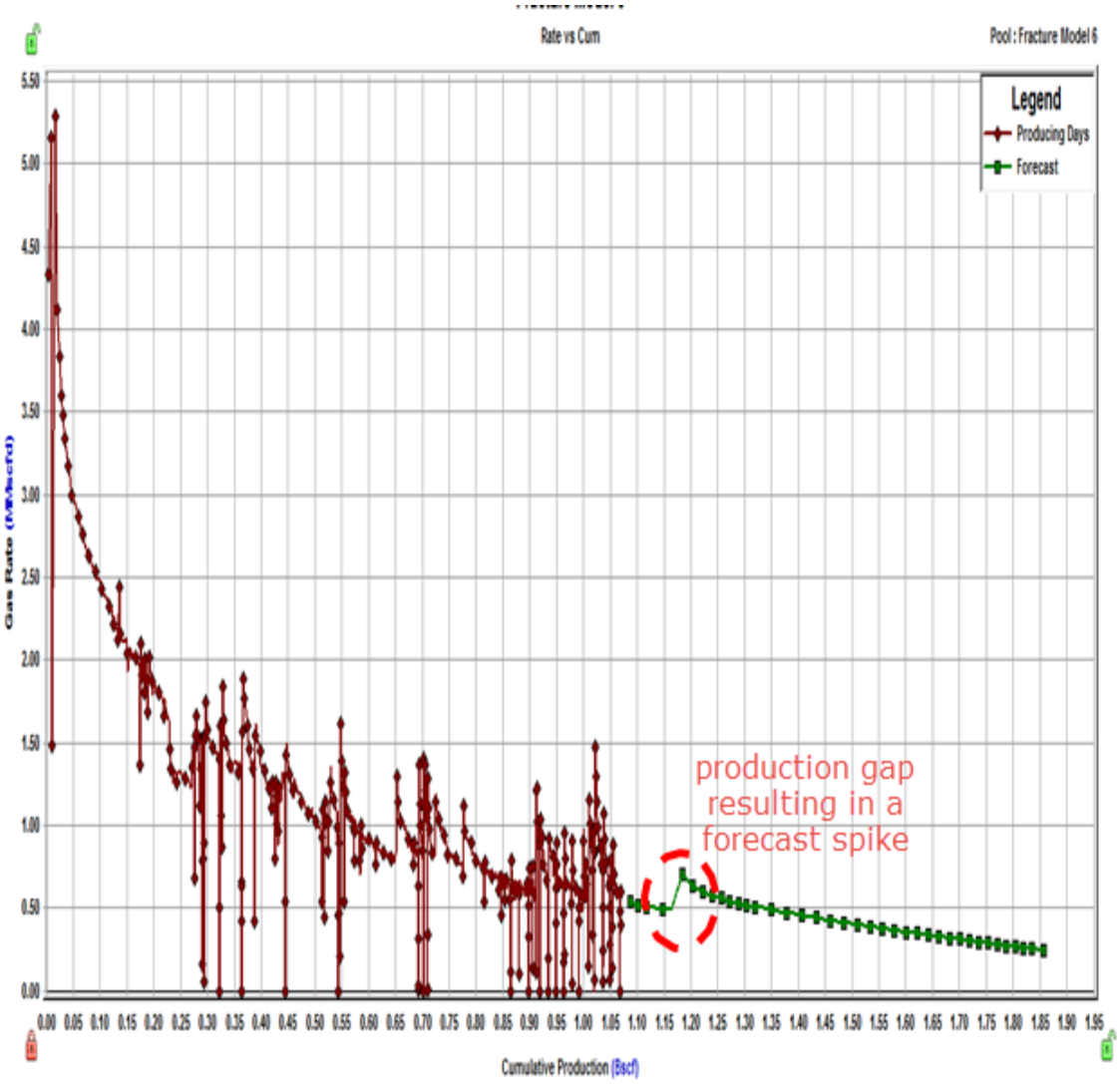
- calculated wellhead pressures are different than the deliverability model
- sandface flowing pressures are higher than modeled due to liquid loading

then the deliverability model used to generate the forecast may not be accurate. Reevaluate the selected deliverability model.



Production gaps

If an imported analytical model does not contain data current to the forecast start date, the forecast fills in the gap between the historical production data used in the model, and the first forecast period. This gap is referred to as a production gap. Options for the handling production gap are set in Properties > Defaults.



If the forecast dips or spikes a few months after the forecast start date, review the following:

- if an additional pressure loss due to liquid loading has occurred
- if the wellhead calculated pressures are representative of operating conditions

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Optimizing your model

Diagnostic maps(found under Bubble Maps in the Property Manager) can help you optimize the performance of your model. These diagnostic maps can highlight areas with operational issues, or can be used to locate areas where potential exists to increase deliverability. The following sections discuss how the information provided by diagnostic maps can help you optimize your gathering system to maximize production and minimize operational costs.

Pressure distribution map

A pressure distribution map is used to see the calculated pressures along the gathering system. Large pressure ranges suggest that various stages of compression and or high pressure losses within pipelines are present. You can customize the pressure distribution range for easy identification of wells operating outside of desired ranges.

Pipeline pressure loss calibration map

A pipeline pressure loss calibration map shows the difference between the measured pipeline pressures (set in Wells > Well Editor > Well Options) and calculated pressures at each of the wells.

Two patterns of pressure loss may be visible: step change losses or systemic losses.

Type of loss	Visual cue on the map	Signifies	Corrections
Step change loss	The color of the pressure bubble shows an increase or decrease at a certain location. This difference remains the same from that location either upstream or downstream.	If measured pressure is less than calculated pressure this could be a data entry problem.	Confirm the following: ■ suction pressure at compressors and pumps ■ gas / liquid ratios ■ disabled pipelinks ■ pipeline diameter values
Step change loss		If measured pressure is greater than calculated pressure, then field pressure losses are not accounted for.	■ check the pipeline velocity to determine if the losses are due to liquids or obstructions ■ check field conditions to make sure losses are not at risers or facilities but in the pipelines

Type of loss	Visual cue on the map	Signifies	Corrections
			■ if the loss should be included in a present or future forecast, add a pressure loss facility; add a fixed pressure loss facility for liquid related pressure loss and a variable pressure loss facility for friction related losses
Systemic loss	Pressure loss differences keep increasing as you progress past a certain point in the gathering system. This is displayed on the map by the bubble colors becoming warmer and warmer.	The system: ■ was modeled using single phase when it should have used multiphase ■ has unaccounted for fluids, such as: missing liquid rates, or 3rd party production ■ has missing elevation data	Confirm or correct the following: ■ use a multiphase correlation ■ compare calculated delivery rates vs. measured rates at delivery points, compressor stations, or pumps ■ enter required elevation data

Gas and water line difference map

The purpose of this map is to show if forecast gas line pressures fall below required water line pressures. In gas systems, you need to make sure that the separator pressure is high enough to push fluids through the pipeline. To validate gas and water line differences, make sure that measured water rates are accounted for.

Well drawdown map

A well's drawdown map is used to quickly identify wells that are not producing at their maximum potential. Generally a 75% drawdown is an optimum operating range. Wells falling below this operating range can indicate potential for increased production.

Well uplift map

A well's uplift map displays the ultimate uplift potential for wells that have been defined using a deliverability model. Cooler colors indicate little uplift potential. Warmer colors indicate larger delivery rate increases are possible, if wellhead pressure is reduced.

Frictional pressure loss map

A frictional pressure loss map can quickly identify restrictions in pipeline capacities resulting from frictional pressure losses. For this link map, you need to customize a frictional pressure loss range that reflects hardware used in the field.

Warmer link colors indicate greater frictional pressure losses, and thus reduced capacity available in lines. This may indicate: undersized pipelines, a potential requirement to twin lines, or an inability to increase rate without causing operational issues. Cooler link colors indicate lines have capacity available due to low frictional pressure losses. This may be an indication of oversized pipelines and therefore the potential to increase the rate in those pipelines.

Gas velocity map

The gas velocity map displays the average gas velocity in each segment of the pipeline. Warm colors indicate faster velocities, cool colors, slower gas velocities. Low gas velocities coinciding with elevation change can indicate the possibility of stagnant liquids. If there is a difference between measured and calculated pressures (pipelines pressure loss calibration map), and gas velocities are low, then stagnant liquids are likely. Low gas velocity and Turner critical velocity maps together can identify the potential for liquid loading.

Delta pressure map

The delta pressure map displays the change in pressure between two nodes connected by a link. This map can be used to identify pipelines with significant pressure losses. Warmer colors indicate a large pressure loss between nodes, while cool colors indicate a small pressure loss. Large pressure changes along lines may indicate the need for additional compression, or that frictional and hydrostatic losses are limiting field delivery rates.

Turner critical velocity map

The Turner critical velocity map displays whether the current velocity in the pipeline segment is above or below the Turner critical velocity. Pipes with red colored links indicate areas where velocities are likely lower than that required to move liquids.

Delta Erosional map

The delta erosional map displays the difference between erosional velocity and gas velocity. This map can be used to identify pipelines with gas velocity approaching erosional velocity. Blue colors indicate a small difference between erosional velocity and gas velocity, while orange-to-red colors indicate a large difference. Small velocity deltas along links may indicate a risk of line erosion.

Note: The erosional velocity constant used to calculate erosional velocity is set under the Properties menu, Defaults.

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Using outputs

These are the output formats for viewing your gathering system data:

- maps
- plots
- reports

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Using plots

The following plots are available:

- production — to view historical production data and compare it to forecasted production decline trends. "Rate vs. Time" or "Rate vs. Cumulative" production plots can be generated. By default, historical data is represented by circles; forecast data is represented by triangles.
- forecast — to view the forecast production, pressures, and cashflow performance of selected facilities throughout the forecast period.
- pressure band — to view wellhead flowing pressure for selected wells, or compressor suction pressure for selected compressors.

The type of data available on each plot type varies with the plot and facility type selected.

The plot toolbar provides functionality to zoom, toggle units (metric / imperial), preview your print, and print the plot. For production and forecast plots, and in the production plotting tab, you can also save your plot settings, and apply your plot settings to all plots of the same facility type.

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Production plotting

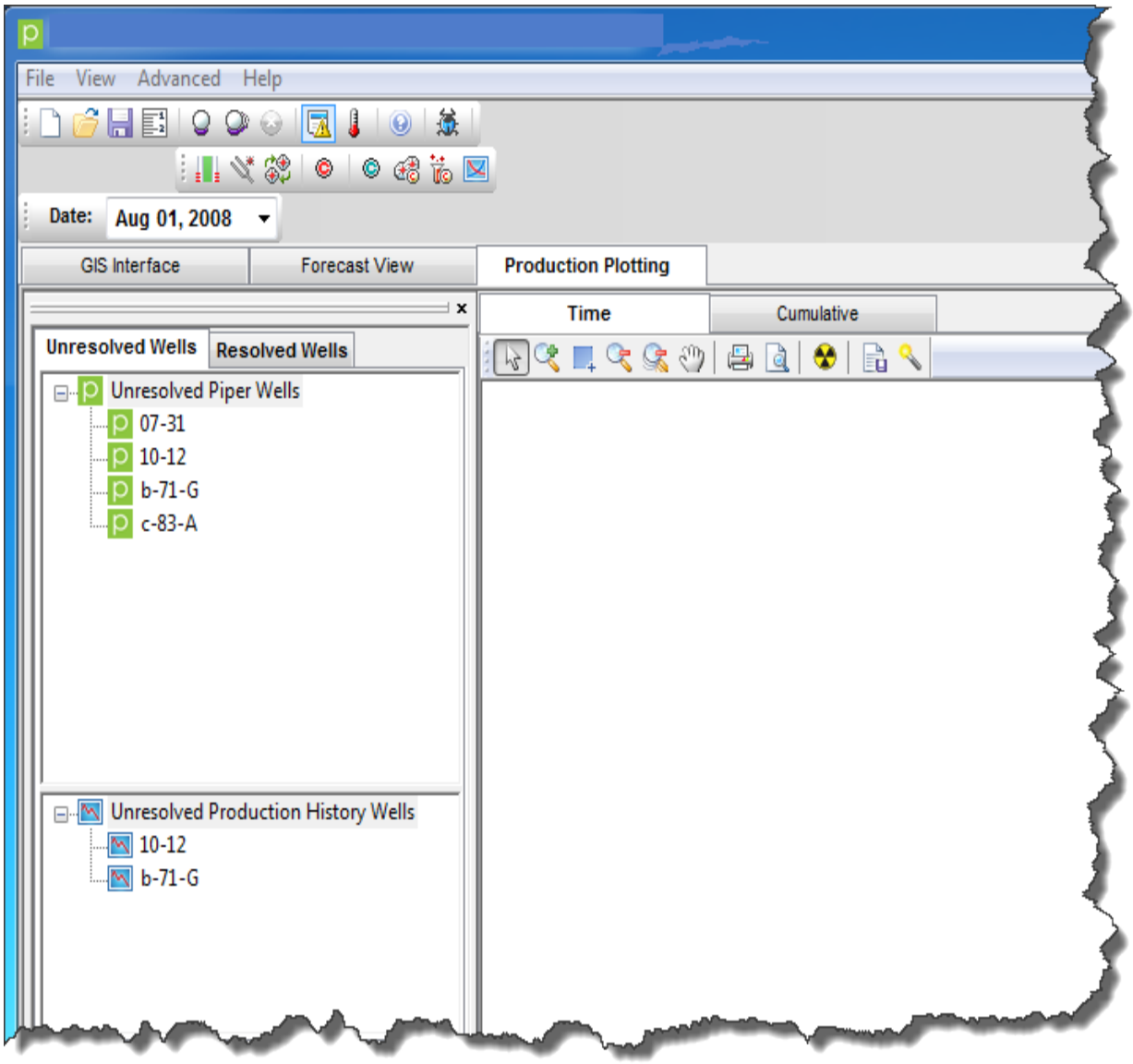
Production plots can be used for validation of your model by comparing forecast trends to historical data. They can also be used to view forecasted production trends. To view historical production on a production plot, you must have imported historical production data either from Harmony or from historical production data in a table or Merak / Dwight file.

Using production plotting

To use production plotting:

1. Click the **Production Plotting** tab.

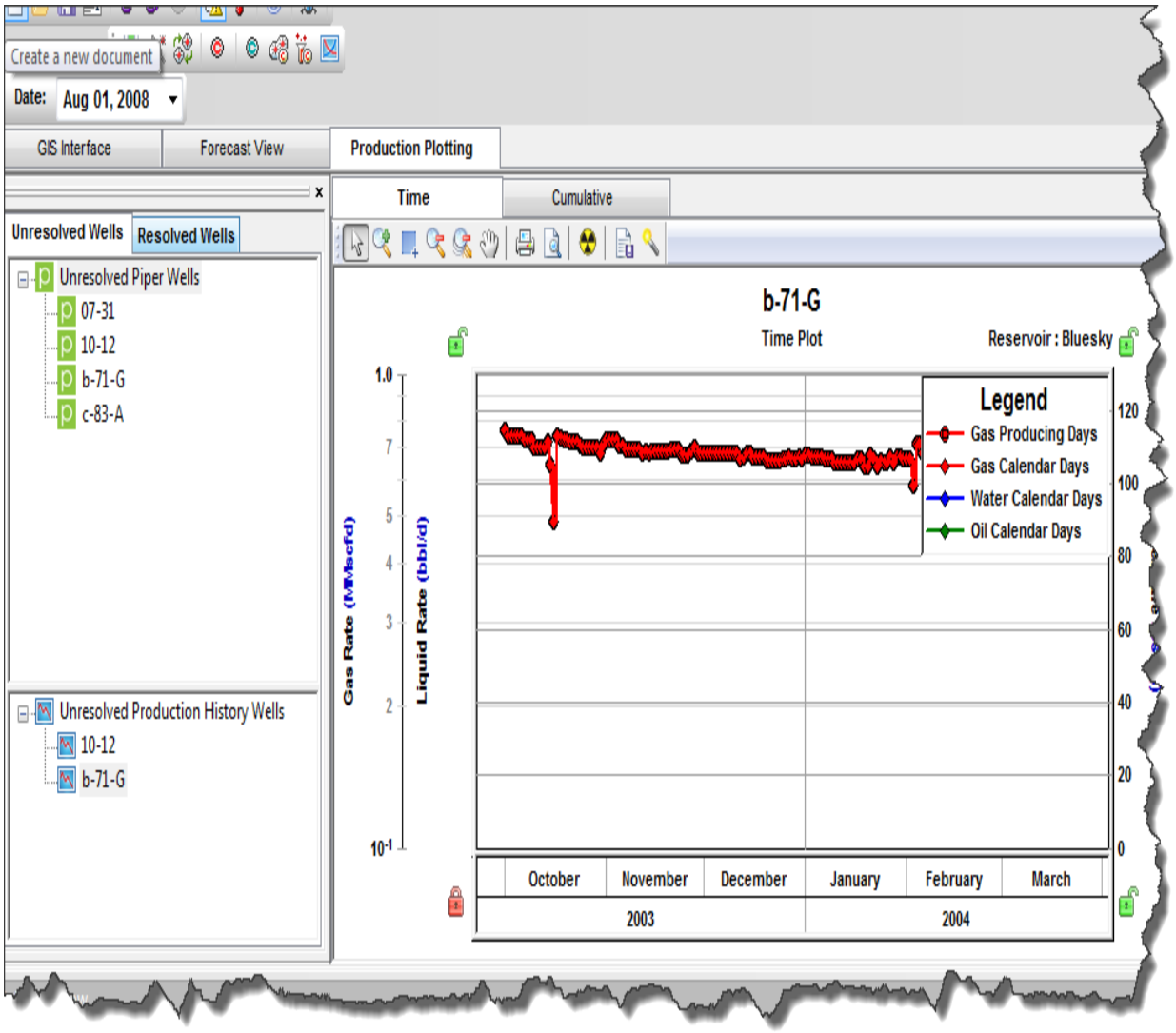
   The main menu options change, and the production plotting tab is displayed.



2. If you have imported historical data (from production .csv files or from Merak / Dwight files), then these wells are listed in the Unresolved Production History Wells pane. Select a well from this pane.

   If this pane is not visible, maximize the application window. Note that wells imported from a Harmony file may be listed in the Resolved Wells pane and / or the Unresolved Production History Wells pane.

   The Time and Cumulative tabs display plots of the imported production data for the selected well.



3. Resolve the selected well. For information on resolving wells, see the following section.

Unresolved and resolved wells

Wells with production data imported from Excel or Merak / Dwight files are listed in the Unresolved Production History Wells pane. If this pane is not visible, maximize the application window. To view historical and forecast production data on the same plot, unresolved production history wells must be matched to unresolved wells existing in the current model. Unresolved wells existing in the current model, or that are not matched on import from a Harmony file, are listed in the Unresolved Wells tab.

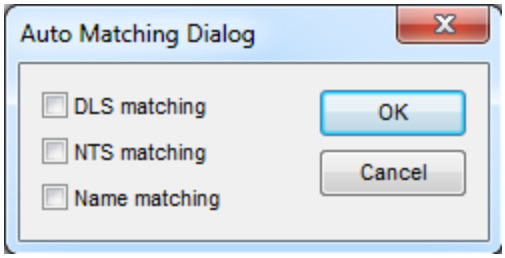
Note: Wells can be resolved manually or automatically.

Resolving wells automatically

To resolve wells automatically:

1. Click the **Advanced** menu and select **Match Wells**.

   The Auto Matching dialog box opens.

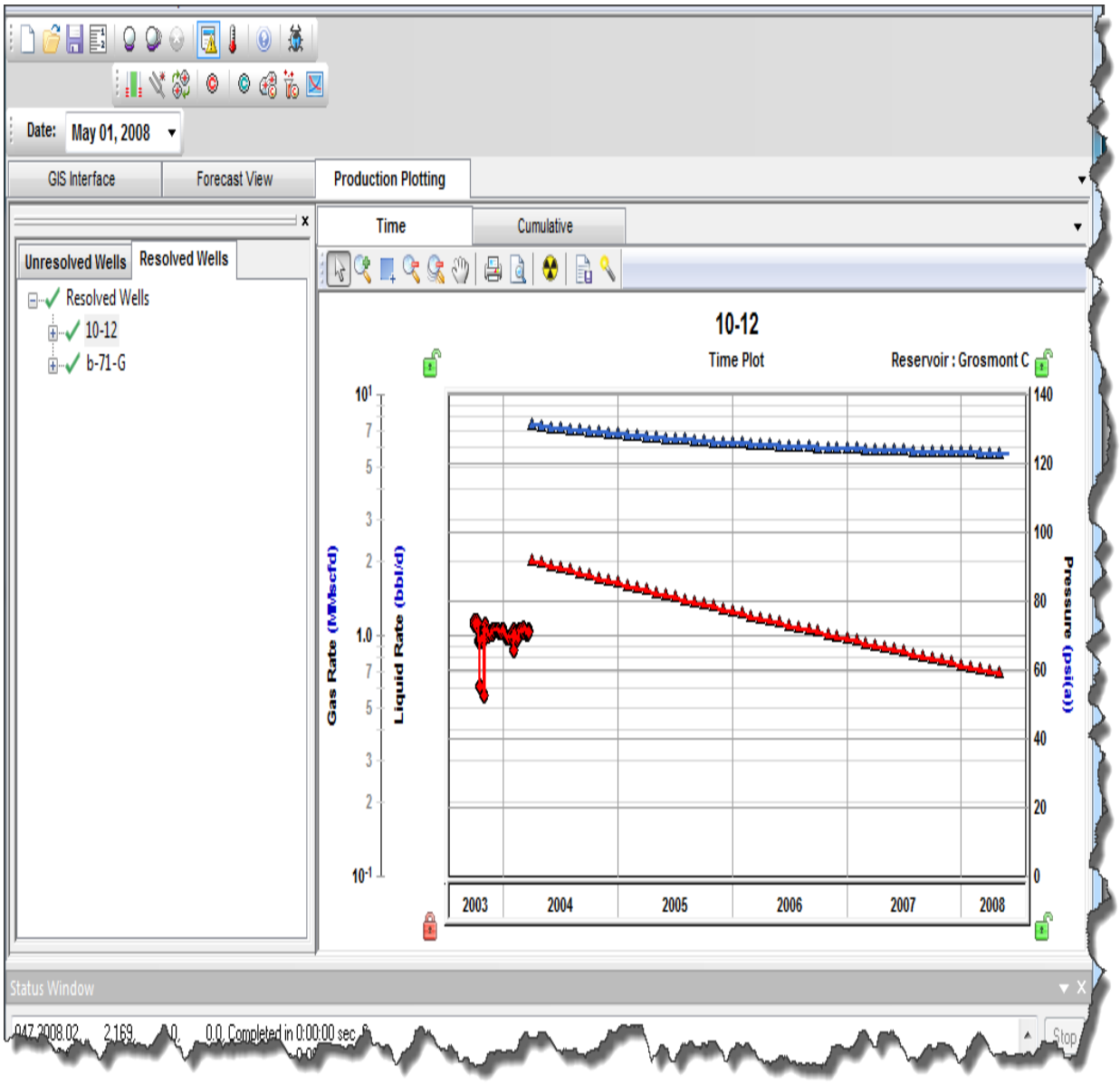


2. Select the matching mechanism to use:

   - DLS matching
   - NTS matching
   - Name matching

3. Click **OK**.

   If the well resolves, it is removed from both the list in the Unresolved Production History Wells pane, and the Unresolved Wells tab. If all wells resolve, the Unresolved Production History Wells pane is no longer visible. Resolved wells are added to the list in the Resolved Wells tab. Both historic and forecast production data are displayed on the plots. By default, historical data is represented as circles; forecast data is represented as triangles.



Resolving wells manually

To resolve wells manually:

1. Select a well in the **Unresolved Wells** tab.
2. Drag-and-drop the selected well on top of its corresponding well in the **Unresolved Production History Wells** pane.

   If the well resolves, it is removed from both the list in the Unresolved Production History Wells pane, and the Unresolved Wells tab. If all wells resolve, the Unresolved Production

History Wells pane is no longer visible. Resolved wells are added to the list in the Resolved Wells tab. Both historic and forecast production data are displayed on the plots. By default, historical data is represented as circles; forecast data is represented as triangles.

If the well fails to resolve, repeat steps 1 and 2.

Note: If the well was resolved incorrectly, right-click the well in the Resolved Wells tab and select **Split Well**. The well is added back to the Unresolved Wells tab and the Unresolved Production History Wells pane.

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Using forecast plots

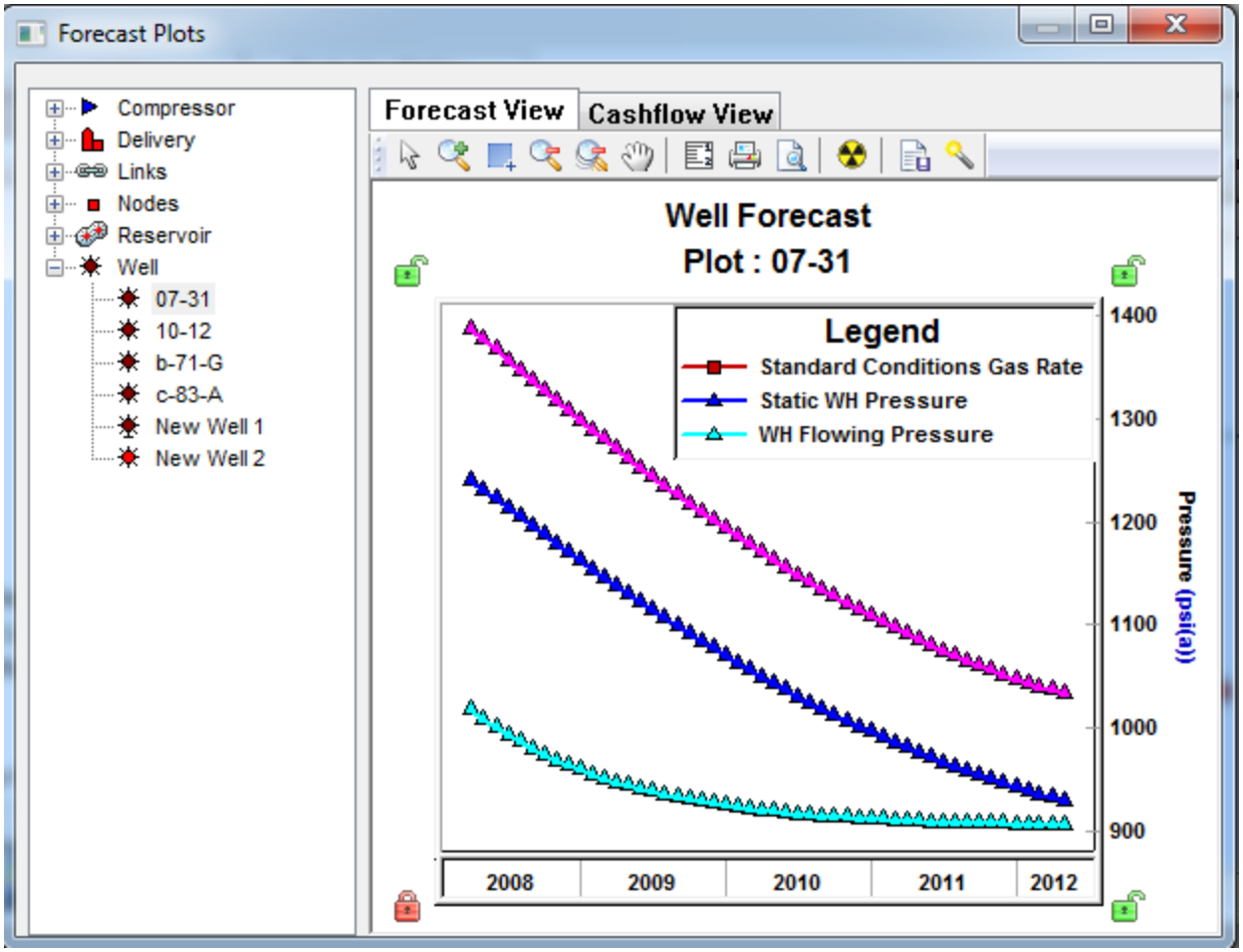
Using the forecast plot, you can view the forecast and cashflow performance of all facilities in the gathering system throughout the forecast period.

Note: You must run a forecast to view forecast plots.

1. Click the **Output** menu and select **Plots**.

   The Forecast Plots dialog box opens. You can select from two plots:

   - Forecast View
   - Cashflow View



2. Select a facility from the left-side box

   The plot for the selected facility is generated to the right.

3. To adjust the plot scale, click the appropriate icons on the axes ( , ), and click drag the cursor up and down the scale values.

4. To change the data displayed on the plot, right-click in the legend, select **Show on Plot**, and select the data from the context menu.

   Note: If the legend is not visible on the plot, right-click in the plot and select **Show Legend**.

Plot type	Plot data available for display
Forecast View	standard conditions gas rate, in situ gas rate, recombined gas rate, static wellhead pressure, wellhead flowing pressure, reservoir pressure, wellsite line temperature
Cashflow View	**Well data:** gas price, oil price, gas sales, oil sales, cash flow, operating costs, gas rate **Facility data:** cashflow, operating costs (fixed and variable), gas rate, fuel gas cost, fuel gas rate

5. Click **Close**.

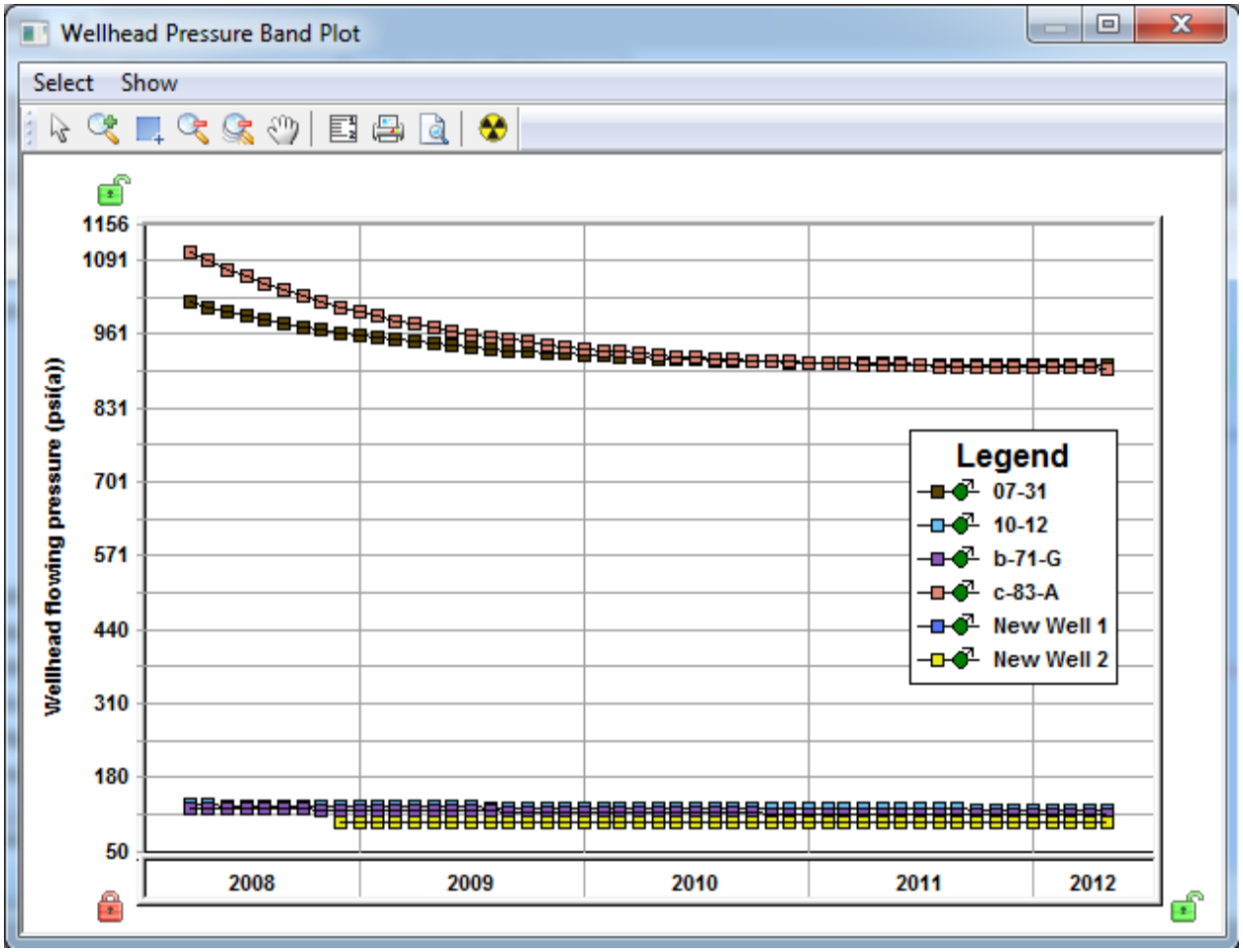
Using pressure band plots

You can view wellhead flowing pressure for selected wells and compressor suction pressure for selected compressors using pressure band plots.

Note: You must run a forecast to view pressure band plots.

1. Click the **Outputs** menu and select **Pressure Band Plots**.

   The Wellhead Pressure Band Plot dialog box opens.



2. Click the **Select** menu and select either **Wells** or **Compressors**.

   The Select Wells dialog box opens.

3. Select the wells you want to display and click **OK**.

4. Click **Show** and select the facility types (wells and / or compressors) to display on the plot.

5. To change the facilities displayed on the plot, right-click in the legend, select **Show on Plot**, and select the facilities from the context menu.

   Or, repeat steps 2 and 3.

   You can only display wells and / or compressors on pressure band plots.

6. Click **Close**.

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Using reports

You can use reports to preview, print, and export data from your gathering system model to a variety of platforms.

If your reports are not displayed, verify the following:

- a forecast must be run for data to be in the database.
- rights on the database must be available to the user. If the database has been copied to a CD, the database file may be read-only.
- MS Access components must be installed correctly.
- if you still cannot view your reports, contact us.

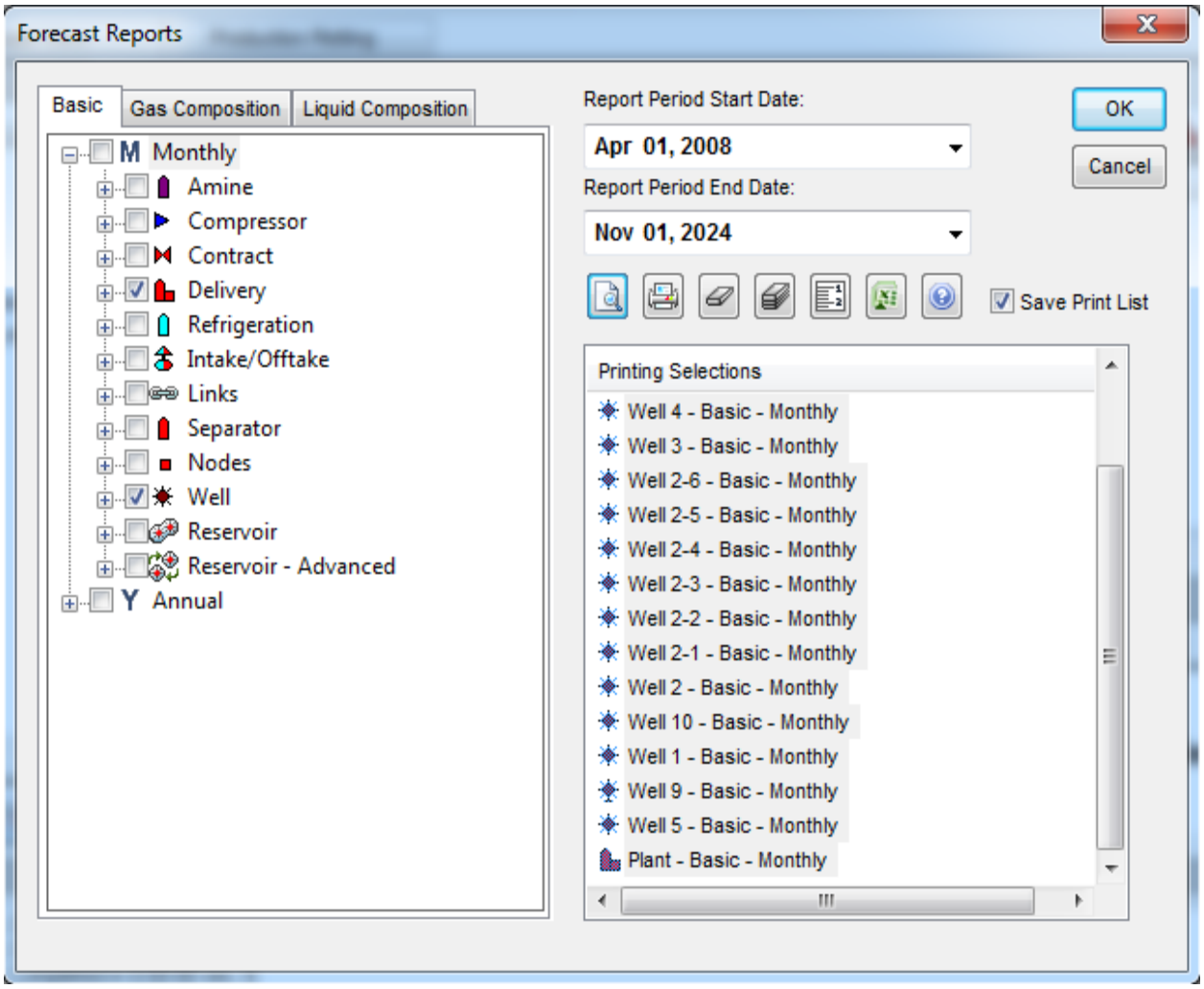
Forecast reports

To generate a forecast report:

Note: You must run a forecast to generate a forecast report.

1. Click the **Output** menu and select **Forecast Reports**.

   The Forecast Reports dialog box opens.



2. Click the tab for the data you want to export: **Basic**, **Gas Composition**, or **Liquid Composition**.

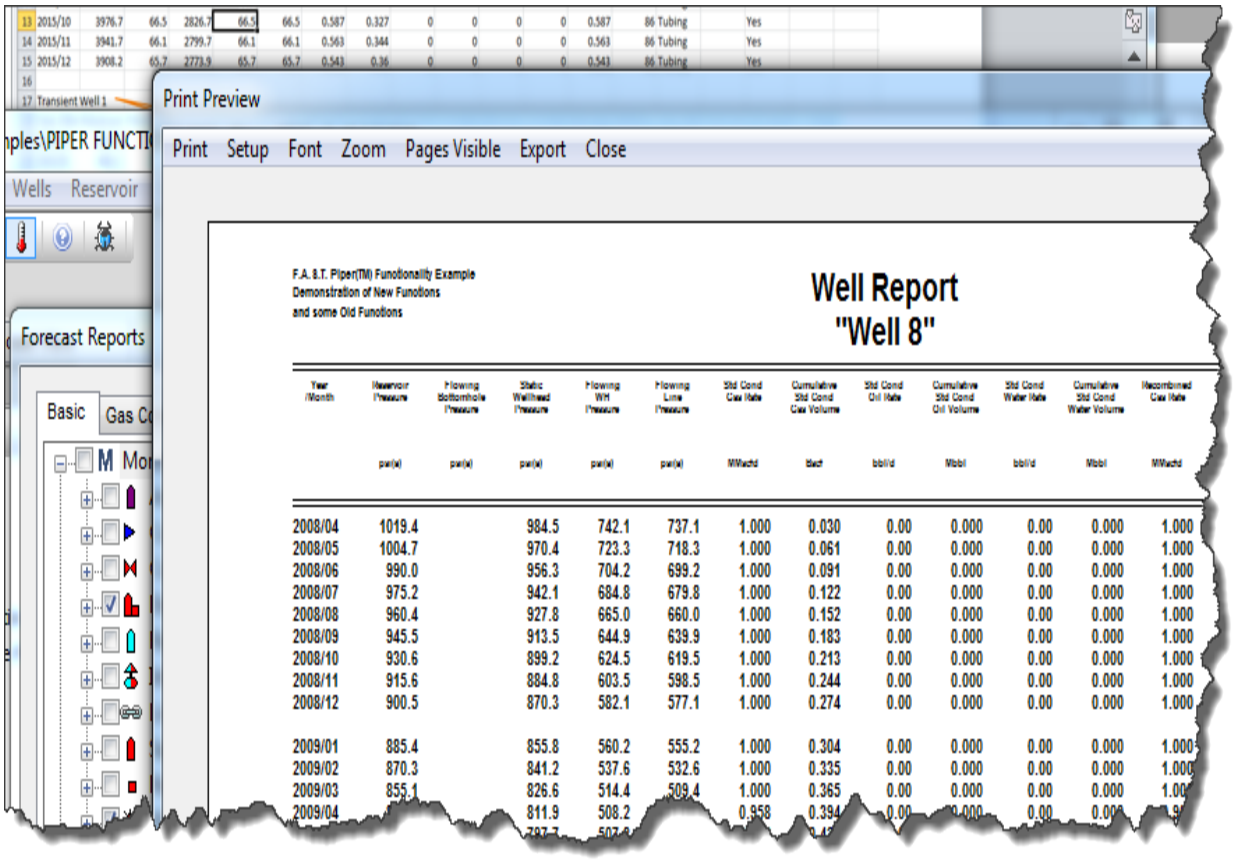
3. Select the facilities for your reporting time period from the left-side box.

   Facility data can be reported monthly or yearly. The selected facilities are added to the Printing Selections box.

4. Select a **Report Period Start Date** and a **Report Period End Date** from the drop-down lists.

5. Select facilities from the **Printing Selections** box.

6. (Optional) Click the **Print Preview** icon ( ) to preview the report for the selected facilities.



Year /Month	Reservoir Pressure	Flowing Bottomhole Pressure	Static Wellhead Pressure	Flowing WH Pressure	Flowing Line Pressure	Std Cond Gas Rate	Cumulative Std Cond Gas Volume	Std Cond Oil Rate	Cumulative Std Cond Oil Volume	Std Cond Water Rate	Cumulative Std Cond Water Volume	Recombined Gas Rate
	psia	psia	psia	psia	psia	MMscfd	Bscf	bbl/d	Mbbl	bbl/d	Mbbl	MMscfd
2008/04	1019.4		984.5	742.1	737.1	1.000	0.030	0.00	0.000	0.00	0.000	1.000
2008/05	1004.7		970.4	723.3	718.3	1.000	0.061	0.00	0.000	0.00	0.000	1.000
2008/06	990.0		956.3	704.2	699.2	1.000	0.091	0.00	0.000	0.00	0.000	1.000
2008/07	975.2		942.1	684.8	679.8	1.000	0.122	0.00	0.000	0.00	0.000	1.000
2008/08	960.4		927.8	665.0	660.0	1.000	0.152	0.00	0.000	0.00	0.000	1.000
2008/09	945.5		913.5	644.9	639.9	1.000	0.183	0.00	0.000	0.00	0.000	1.000
2008/10	930.6		899.2	624.5	619.5	1.000	0.213	0.00	0.000	0.00	0.000	1.000
2008/11	915.6		884.8	603.5	598.5	1.000	0.244	0.00	0.000	0.00	0.000	1.000
2008/12	900.5		870.3	582.1	577.1	1.000	0.274	0.00	0.000	0.00	0.000	1.000
2009/01	885.4		855.8	560.2	555.2	1.000	0.304	0.00	0.000	0.00	0.000	1.000
2009/02	870.3		841.2	537.6	532.6	1.000	0.335	0.00	0.000	0.00	0.000	1.000
2009/03	855.1		826.6	514.4	509.4	1.000	0.365	0.00	0.000	0.00	0.000	1.000
2009/04			811.9	508.2		0.958	0.394	0.00	0.000	0.00	0.000	

7. (Optional) Print the report, or export it to Excel.
8. Click **OK**.

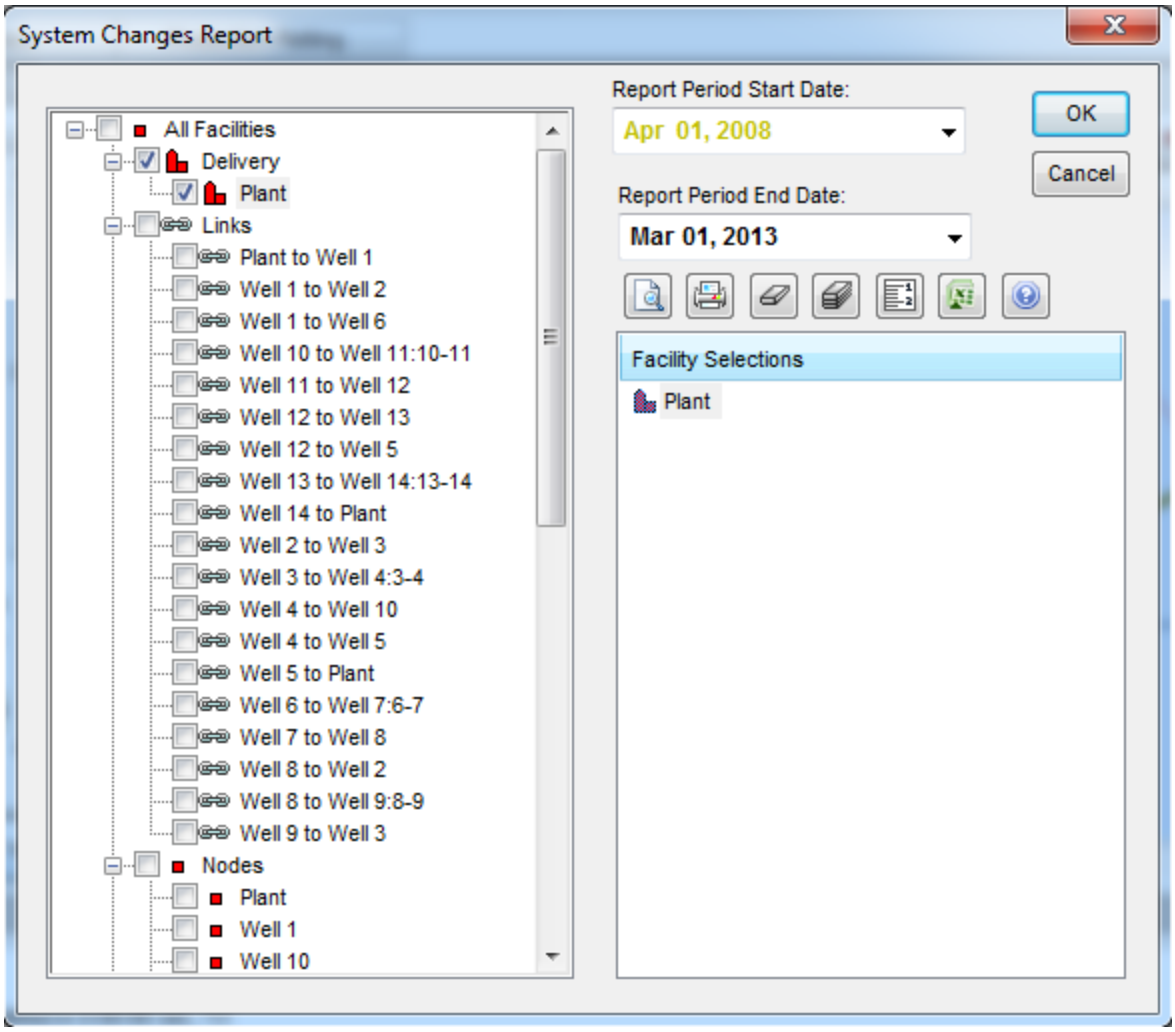
System changes reports

The system changes reports details changes in the configuration of your gathering system through time.

To generate a system changes report:

1. Click the **Output** menu and select **System Changes Reports**.

   The System Changes Report dialog box opens.



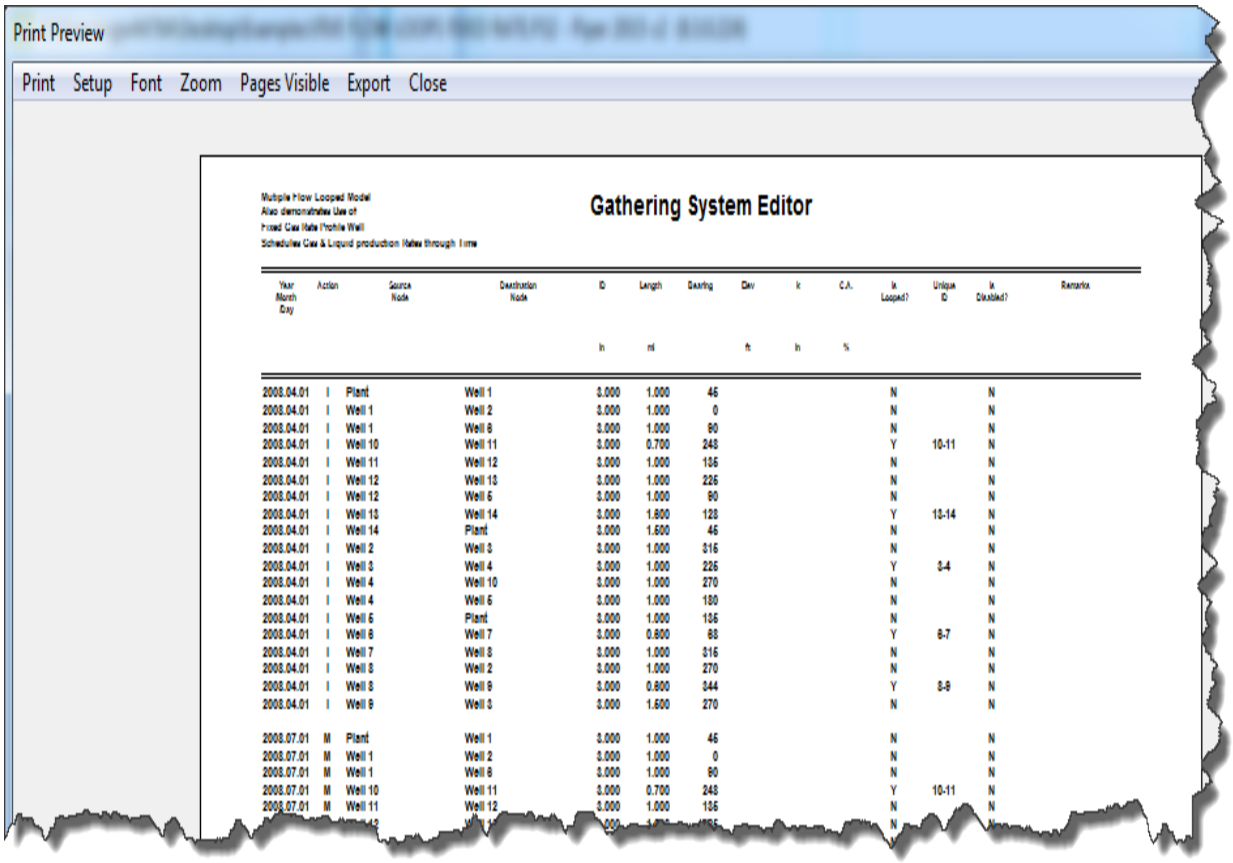
2. Select facilities from the left-side box.

   The facilities are added to the Facility Selections box.

3. Select a Report Period Start Date and a Report Period End Date from the drop-down lists.

4. Select facilities from the Facility Selections box.

5. (Optional) Click the **Print Preview** icon ( ) to preview the report for the selected facilities.



6. Review the Action column.

   The actions are defined as follows:

   - I — initiated; added at the model start date
   - D — deleted from the model
   - M — modified; facility was added in prior dates, but input / forecast parameters have been modified on the listed date
   - A — added; facility did not exist in prior dates, and is now added on the listed date

   This report allows you to quickly determine dates where changes have been made in the model.

7. (Optional) Print the report, or export it to Excel.

8. Click **OK**.

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Using maps

Gathering system models are often used to investigate ways to maximize hydrocarbon production at minimum cost. Bubble and link maps can be used diagnostically to identify areas within the gathering system where optimization opportunities exist.

Note: You must run a forecast to view bubble or link maps.

The following can be used to identify opportunities in a gathering system:

- default bubble maps
- default link maps

In addition, bubble and link maps may be customized and edited to identify specific operational characteristics. For more information, see:

- creating custom maps
- editing bubble maps and link maps

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Using default bubble maps

Piper includes the following default bubble maps to view gathering system diagnostics:

- pressure distribution
- pipeline pressure loss calibration
- gas and water line difference
- well drawdown
- well uplift

Note: You must run a forecast to see a bubble map.

To use default bubble maps, click one of the default bubble maps in the Property Manager. The GIS interface displays the data assigned to each bubble map attribute. See modifying bubble map preferences for more details. Review the bubble map legend for information on potential problem areas and / or areas that might offer optimization opportunities in your gathering system. These areas can be identified by bubble color, size, shape, and angle (if applicable).

To edit bubble maps, see editing bubble maps.

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Using default link maps

Piper includes the following default link maps to view gathering system diagnostics:

- frictional pressure loss
- gas velocity
- delta pressure
- Turner critical velocity

Note: You must run a forecast to see a link map.

To use default link maps, click one of the default link maps in the Property Manager. The GIS interface displays the data assigned to each link map attribute. See modifying link map preferences for more details. Review the link map legend for information on potential problem areas and / or areas that might offer optimization opportunities in your gathering system. These areas can be identified by line color and thickness.

To edit link maps, see editing link maps.

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Creating custom maps

You can create custom bubble and link maps in addition to the default bubble and link maps.

To create a custom map:

1. Choose one of the following:

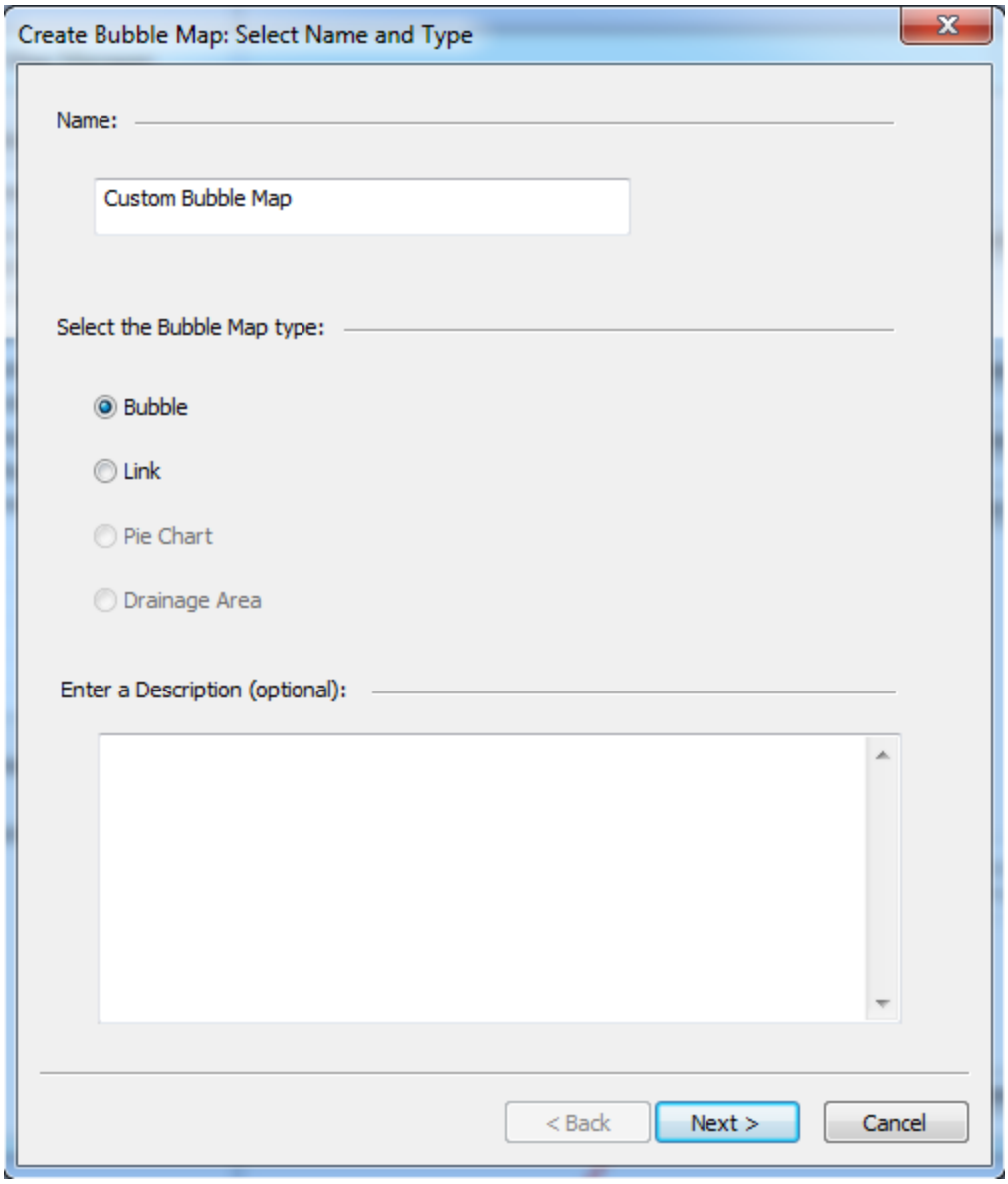
   - Right-click an existing bubble map in the Property Manager, and select **Open Bubble Map Manager**. Then, click **Create Map**.

     Or, click the **Properties** menu, and select **Bubble or Link Map Customization**. Then, click **Create Map**.

     Or, click the **Bubble Map** icon () in the GIS navigation toolbar. Then, click **Create Map**.

   - or, click the  icon Property Manager and select **Add Bubble Map Layer**.

   The Create Bubble Map dialog box opens.



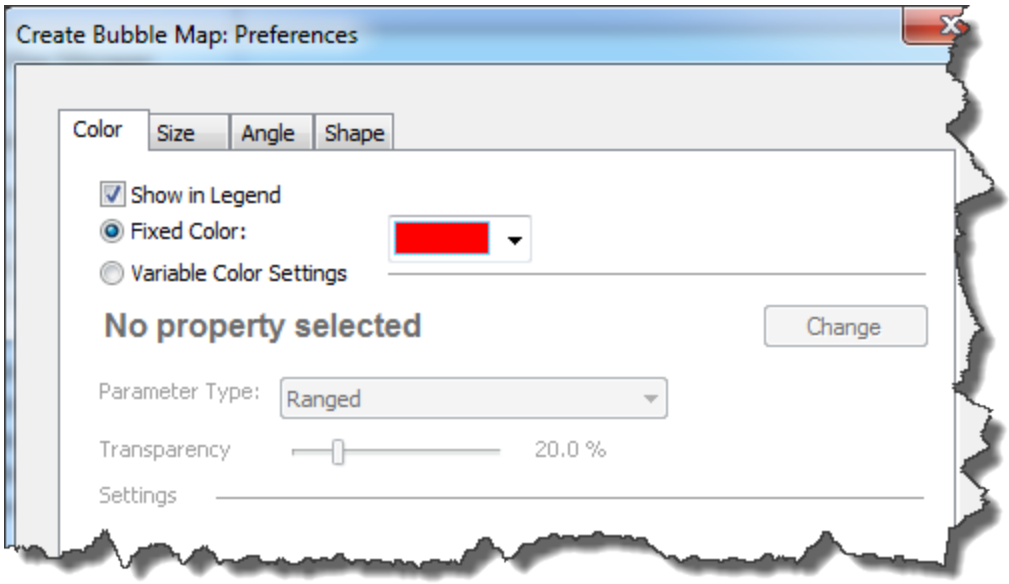
2. (Optional) Enter a name for your bubble map.

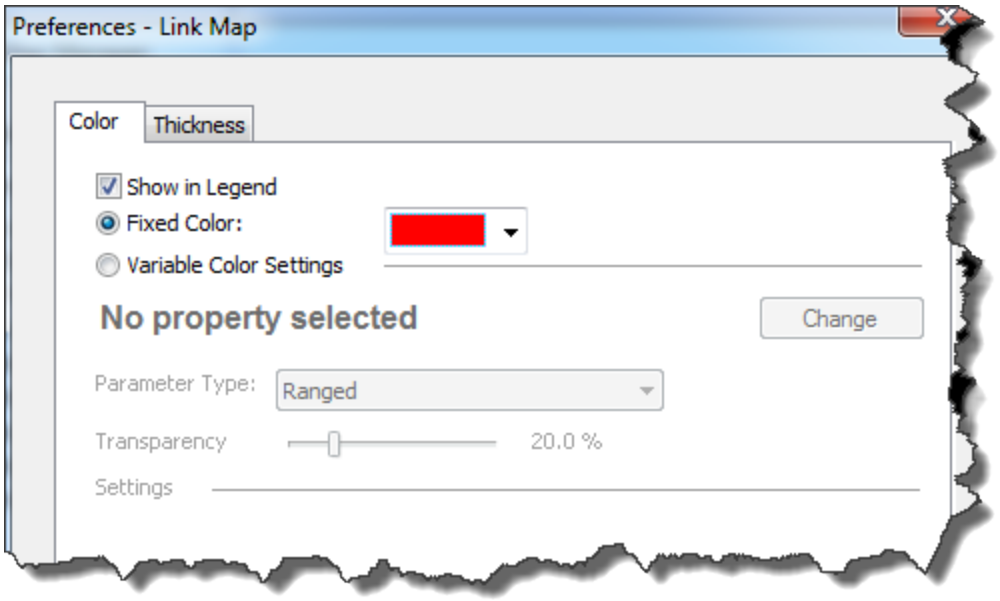
3. Click **Bubble or Link** and then click **Next**.

4. Click **Select Specific Entities** to apply the bubble or link map to certain entities only.

   Or, click **Select by Entity Type** to apply the bubble or link map to all entities of a certain type and then click **Next**.

   The Preferences dialog box opens.





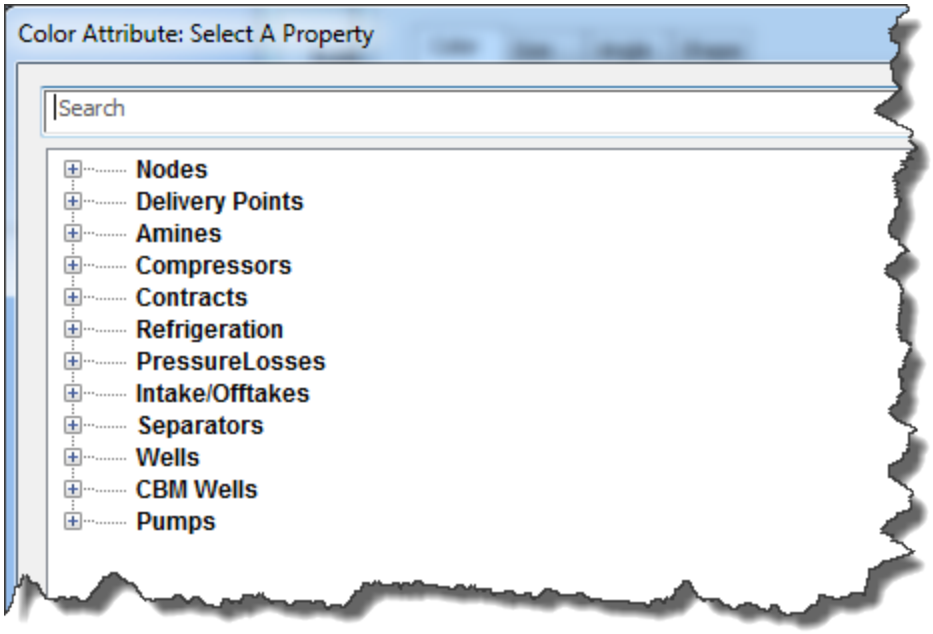
5. Select from the following bubble map attributes:

Attribute	Bubble Map	Link Map
color	✓	✓
size	✓	×
angle	✓	×
shape	✓	×
thickness	×	✓

6. Click **Variable <color> Settings** to select a property for the bubble map attribute, and then click the **Change** button.

   The Select A Property dialog box opens.

7. Select a property; then click **OK**.



   Note that each bubble map attribute can have its own property.

8. The following options can be modified:

   - High-Low Range — you can specify a specific diameter for the bubble according to low and high attribute values.
   - Ranged — you can set a range of values for the selected property
   - Set Point — you can specify a single numeric value to compare against, and then set the operation to use in the comparison. (This option does not allow you to set a range of values.)
   - Scale Factor — you can set incremental size increases based on a fixed attribute value (e.g., one inch for every 5 MMscf of OGIP).
   - Auto Range — calculates a range based on the data for the entities used in the bubble map.
   - Reset Ranges... — resets the ranges to either the last-saved ranges, or the default ranges.

- Show in Legend — select this option to display the tabbed preference in the GIS map legend.

Note: Not all of these options apply to each of the bubble map attributes listed in step 5.

9. Click **Finish**.

   The bubble map is displayed on the map, appended to the bubble maps list and to the bubble maps layers in the Property Manager.

10. Click **Close**.

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Editing bubble maps

You can delete, copy, and rename bubble maps, as well as modify your bubble map preferences.

Deleting a bubble map

To delete a bubble map:

1. Right-click the bubble map in the Property Manager, and select **Open Bubble Map Manager**.

   Or, click the **Properties** menu, and select **Bubble Map Customization**.

   Or, click the **Bubble Map** icon ( ) on the GIS navigation toolbar.

   The Bubble Map Manager dialog box opens.

2. Select the bubble map from the bubble maps list.

3. Click **Delete**.

   The bubble map is removed from the map, the bubble maps list, and from the bubble maps layers in the Property Manager.

   Note: No confirmation prompt is provided prior to deleting the bubble map.

4. Click **Close**.

Copying a bubble map

To copy a bubble map:

1. Right-click the bubble map in the Property Manager, and select **Open Bubble Map Manager**.

   Or, click the **Properties** menu, and select **Bubble Map Customization**.

   Or, click the **Bubble Map** icon ( ) on the GIS navigation toolbar.

   The Bubble Map Manager dialog box opens.

2. Select the bubble map from the bubble maps list.

3. Click **Copy**.

   A copy of the selected bubble map is displayed on the map, appended to the end of the bubble maps list and to the bubble maps layers in the Property Manager.

4. Click **Close**.

Renaming a bubble map

To rename a bubble map:

1. Right-click the bubble map in the Property Manager, and select **Open Bubble Map Manager**

   Or, click the **Properties** menu, and select **Bubble Map Customization**.

   Or, click the **Bubble Map** icon () on the GIS navigation toolbar.

   The Bubble Map Manager dialog box opens.

2. Select the bubble map from the bubble maps list.

3. Click the **Name** field and type in the new name.

4. Click **Accept Change**.

   The bubble map is renamed in the bubble maps list and in the bubble maps layers in the Property Manager.

5. Click **Close**.

Modifying your bubble map preferences

To modify your preferences for the bubble map:

1. Choose one of the following:

   - Right-click the bubble map in the Property Manager, and select **Open Bubble Map Manager**.

     Or, click the **Properties** menu, and select **Bubble Map Customization**.

     Or, click the **Bubble Map** icon () on the GIS navigation toolbar. Then:

     a. Select the bubble map in the bubble maps list.

     b. Click **Configure**.

   - Or, right-click the bubble map layer in the Property Manager and select **Options**

     Or, right-click in the bubble map legend and select **Options**.

   The Bubble Map Editor dialog box opens.

2. Click the **Entities** tab and:

- click **Select Specific Entities** to apply the bubble map to certain entities only
- or, click **Select by Entity Type** to apply the bubble map to all entities of a certain type

3. Click the **Preferences** tab and select from the following bubble map attributes:
   - color
   - size
   - angle
   - shape
4. Click **Variable <color> Settings** to select a property for the bubble map attribute; then click the **Change** button.

   The Select A Property dialog box opens.

5. Select a property, then click **OK**.

   Note that each bubble map attribute can have its own property.

6. The following options can be modified:
   - High-Low Range — you can specify a specific diameter for the bubble according to low and high attribute values.
   - Ranged — you can set a range of values for the selected property
   - Set Point — you can specify a single numeric value to compare against, and then set the operation to use in the comparison. (This option does not allow you to set a range of values.)
   - Scale Factor — you can set incremental size increases based on a fixed attribute value (e.g., one inch for every 5 MMscf of OGIP).
   - Auto Range — calculates a range based on the data for the entities used in the bubble map.
   - Reset Ranges... — resets the ranges to either the last-saved ranges or, the default ranges.
   - Show in Legend — select this option to display the size, color, angle and / or shape in the GIS map legend.
7. Click **OK**.

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Editing link maps

You can delete, copy, and rename link maps, as well as modify your link map preferences.

Deleting a link map

To delete a link map:

1. Right-click the link map in the Property Manager, and select **Open Bubble Map Manager**.

   Or, click the **Properties** menu, and select **Link Map Customization**.

   Or, click the **Bubble Map** icon () on the GIS navigation toolbar.

   The Bubble Map Manager dialog box opens.

2. Select the link map from the bubble maps list.

3. Click **Delete**.

   The link map is removed from the map, the bubble maps list and from the bubble maps layers in the Property Manager.

   Note: No confirmation prompt is provided prior to deleting the link map.

4. Click **Close**.

Copying a link map

To copy a link map:

1. Right-click the link map in the Property Manager, and select **Open Bubble Map Manager**.

   Or, click the **Properties** menu, and select **Link Map Customization**.

   Or, click the **Bubble Map** icon () on the GIS navigation toolbar.

   The Bubble Map Manager dialog box opens.

2. Select the link map from the bubble maps list.

3. Click **Copy**.

   A copy of the selected link map is displayed on the map, appended to the end of the bubble maps list and to the bubble maps layers in the Property Manager.

4. Click **Close**.

Renaming a link map

To rename a link map:

1. Right-click the link map in the Property Manager, and select **Open Bubble Map Manager**.

   Or, click the **Properties** menu, and select **Link Map Customization**.

   Or, click the **Bubble Map** icon () on the GIS navigation toolbar.

   The Bubble Map Manager dialog box opens.

2. Select the link map from the bubble maps list.

3. Click the **Name** field and type in the new name.

4. Click **Accept Change**.

   The link map is renamed in the bubble maps list and in the bubble maps layers in the Property Manager.

5. Click **Close**.

Modifying your link map preferences

To modify your preferences for the link map:

1. Choose one of the following:

   - Right-click the link map in the Property Manager, and select **Open Bubble Map Manager**.

     Or, click the **Properties** menu, and select **Link Map Customization**.

     Or, click the **Bubble Map** icon () on the GIS navigation toolbar. Then:

     a. Select the link map in the bubble maps list.

     b. Click **Configure**.

   - Or, right-click the link map layer in the Property Manager and select **Options**
   - Or, right-click in the link map legend and select **Options**.

   The Link Map Editor dialog box opens.

2. Click the **Entities** tab and:

   - click **Select Specific Entities** to apply the link map to certain entities only
   - or, click **Select by Entity Type** to apply the link map to all entities of a certain type

3. Click the **Preferences** tab and select from the following link map attributes:

    - color
    - thickness

4. Click **Variable <color> Settings** to select a property for the link map attribute; then click the **Change** button.

    The Select A Property dialog box opens.

5. Select a property, then click **OK**.

    Note that each link map attribute can have its own property.

6. The following options can be modified:

    - Ranged — you can set a range of values for the selected property
    - Set Point — you can specify a single numeric value to compare against, and then set the operation to use in the comparison. (This option does not allow you to set a range of values.)
    - Auto Range — calculates a range based on the data for the entities.
    - Reset Ranges... — resets the ranges to either the last-saved ranges or, the default ranges.
    - Show in Legend — select this option to display the color and / or thickness in the GIS map legend.

7. Click **OK**.

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Adding economics

Piper includes economic features to evaluate the economic viability of forecasts for different gathering system models. You can create and export net present value (NPV) and system cash flow reports for existing gathering systems and their forecasted conditions. Economic forecasts are run each time an economics report (NPV or cash flow) is generated, or when you view a cashflow plot. If you make changes to economic inputs, it is not necessary to re-run a forecast to update an economic report. The duration of an economics forecast is set in the forecast view.

Important: You must run a forecast for the full duration of the forecast period to generate correct economic reports. If you stop a forecast before it completes, cost data is included for the entire forecast duration, but revenue data is only considered for the duration the forecast is run. Consequently, incorrect reports result.

Inputs

You must enter economic data for your gathering system in order to generate NPV and system cash flow reports.

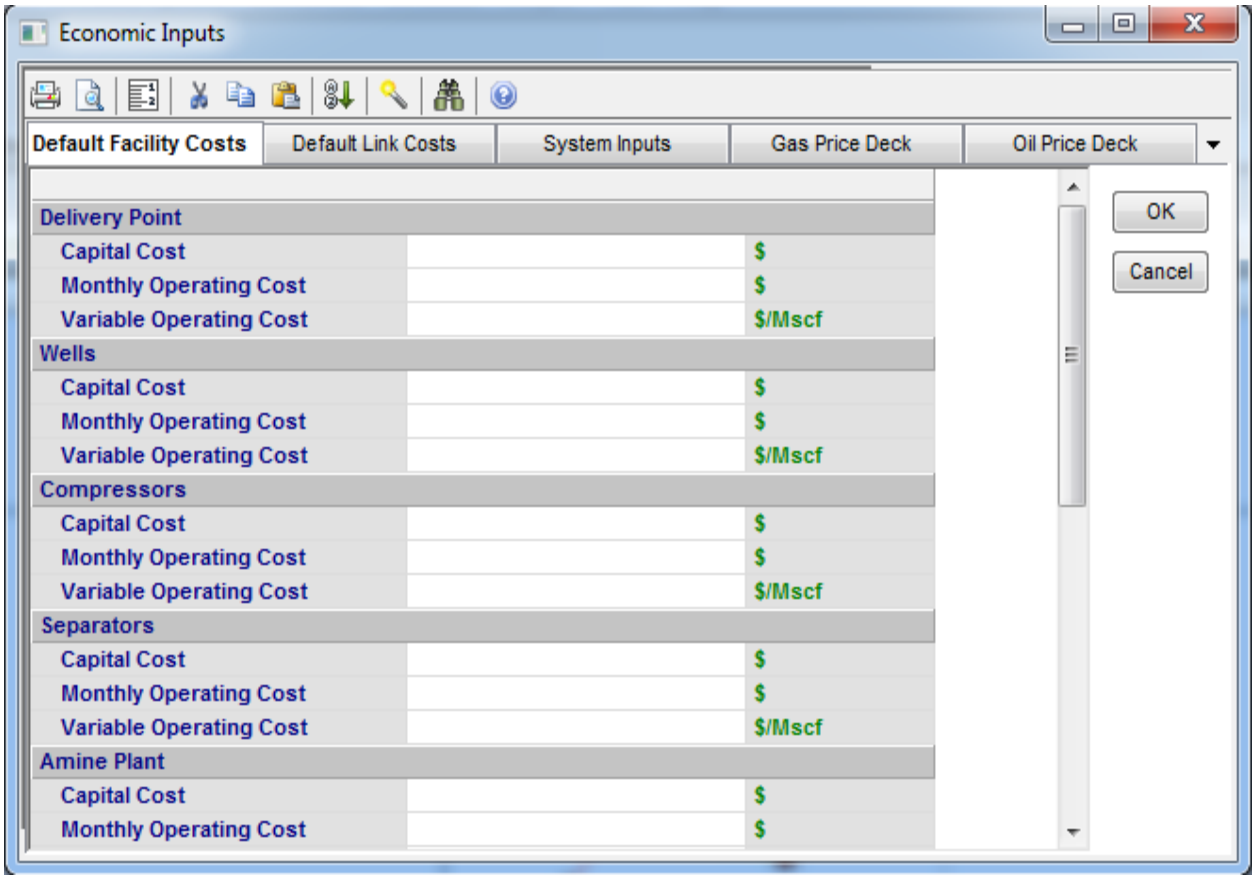
To enter data:

1. Click the **Forecast Options** menu and select **Economics Tracking**.

   The Economics menu is only displayed on the menu toolbar if you follow step 1.

2. Click the **Economics** menu and select **Inputs**.

   The Economic Inputs dialog box opens.

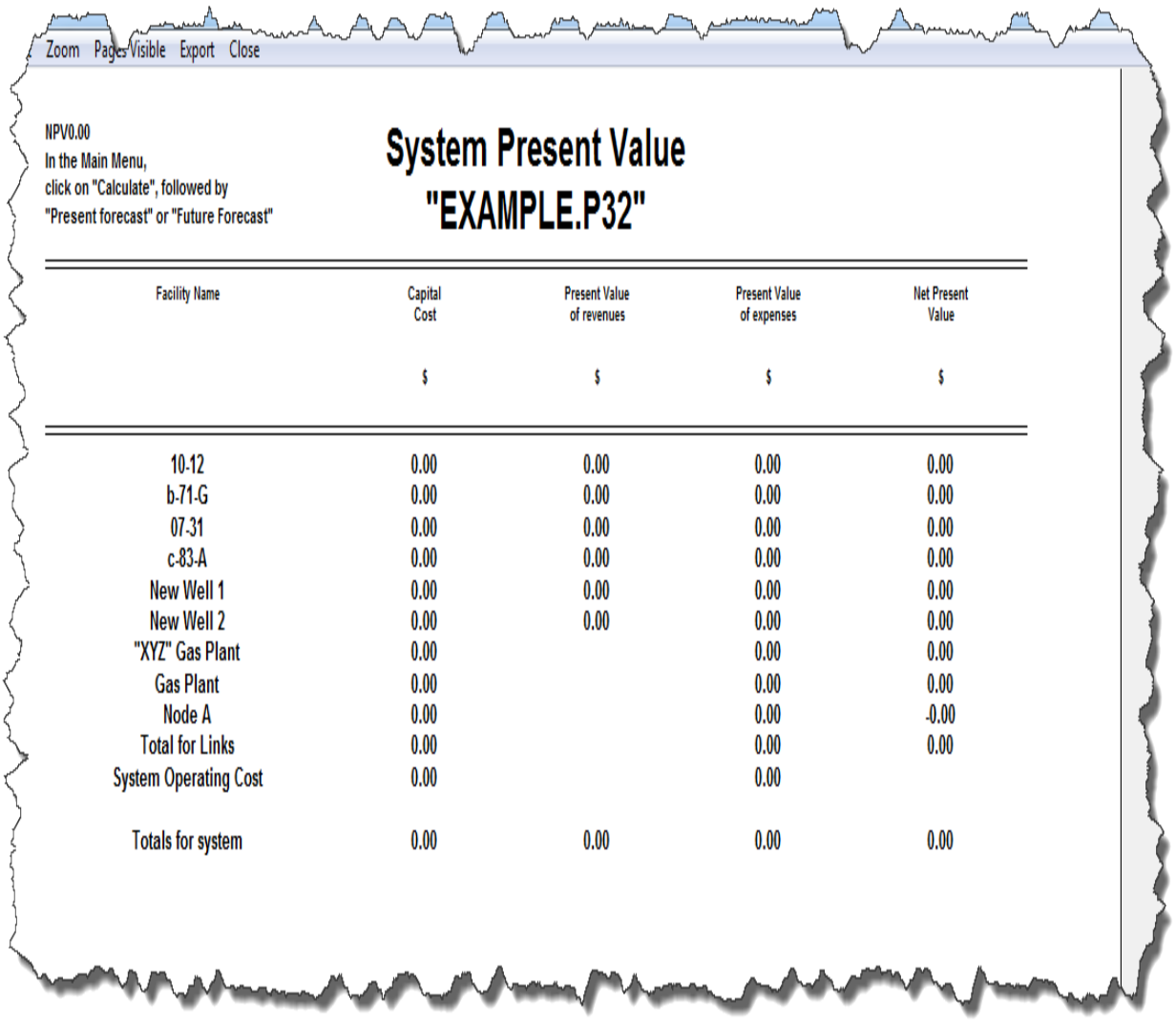


3. (Optional) Enter the **Default Facility Costs**.
4. (Optional) Enter the **Default Link Costs**.
5. (Optional) Enter the **System Inputs**.
6. (Optional) Enter the **Gas Price Deck**.
7. (Optional) Enter the **Oil Price Deck**.
8. Click **OK**.

System NPV Report

The System NPV Report details the capital costs, present value of revenues, present value of expenses, and the sum of these three components for each facility in the model. The NPV of the system as a whole is then calculated as the summation of the NPV of each facility.

To generate a system NPV report, click the **Economics** menu and select **System NPV Report**.



Zoom Pages Visible Export Close

NPV0.00
In the Main Menu,
click on "Calculate", followed by
"Present forecast" or "Future Forecast"

System Present Value
"EXAMPLE.P32"

Facility Name	Capital Cost	Present Value of revenues	Present Value of expenses	Net Present Value
	$	$	$	$
10-12	0.00	0.00	0.00	0.00
b-71-G	0.00	0.00	0.00	0.00
07-31	0.00	0.00	0.00	0.00
c-83-A	0.00	0.00	0.00	0.00
New Well 1	0.00	0.00	0.00	0.00
New Well 2	0.00	0.00	0.00	0.00
"XYZ" Gas Plant	0.00		0.00	0.00
Gas Plant	0.00		0.00	0.00
Node A	0.00		0.00	-0.00
Total for Links	0.00		0.00	0.00
System Operating Cost	0.00		0.00	
Totals for system	0.00	0.00	0.00	0.00

The NPV is calculated at the discount rate specified (if one is entered). If an inflation rate is specified, monthly operating costs and variable operating costs are inflated before discounting.

Both gas and liquid revenue is recorded at the wellhead. Therefore, facilities such as refrigeration units will not have revenue associated with them even though they may be taking off liquids that are to be sold.

System Cash Flow report

The System Cashflow Report provides details of the undiscounted revenues, costs, and cash flows generated for all facilities on a forecast period basis. The report also provides details of capital costs incurred for the forecast period.

To generate a system cash flow report, click the **Economics** menu and select **System Cash Flow Report**.

F.A.S.T. Piper(TM) Demonstration Case
In the Main Menu,
click on "Calculate", followed by
"Present forecast" or "Future Forecast"

System Cashflow Report
"System"

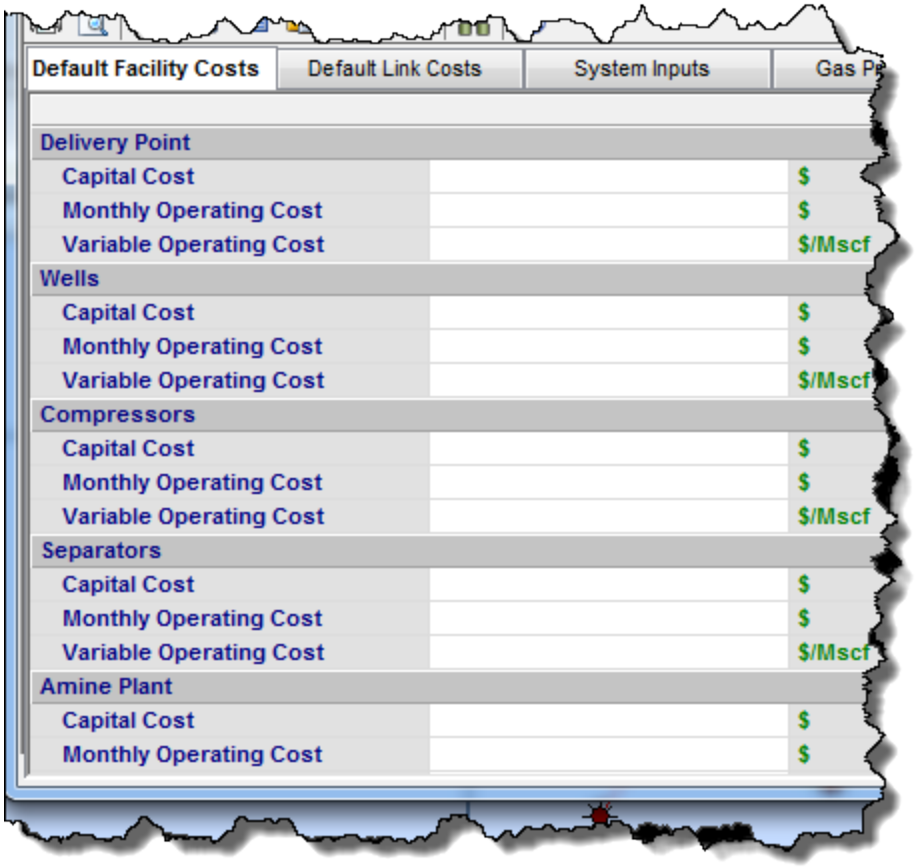
Year /Month	Gross Sales	Fuel Gas Cost	Fixed Cost	Variable Cost	Operating Cashflow	Capital Cost
	$	$	$	$	$	$
1995/01	0.00	0.00	0.00	0.00	0.00	0.00
1995/02	0.00	0.00	0.00	0.00	0.00	0.00
1995/03	0.00	0.00	0.00	0.00	0.00	0.00
1995/04	0.00	0.00	0.00	0.00	0.00	0.00
1995/05	0.00	0.00	0.00	0.00	0.00	0.00
1995/06	0.00	0.00	0.00	0.00	0.00	0.00
1995/07	0.00	0.00	0.00	0.00	0.00	0.00
1995/08	0.00	0.00	0.00	0.00	0.00	0.00
1995/09	0.00	0.00	0.00	0.00	0.00	0.00
1995/10	0.00	0.00	0.00	0.00	0.00	0.00
1995/11	0.00	0.00	0.00	0.00	0.00	0.00
1995/12	0.00	0.00	0.00	0.00	0.00	0.00
1996/01	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	[illegible]	[illegible]	0.00	0.00	

Entering default facility costs

The Default Facility Costs tab lists all of the facility types that have economic attributes.

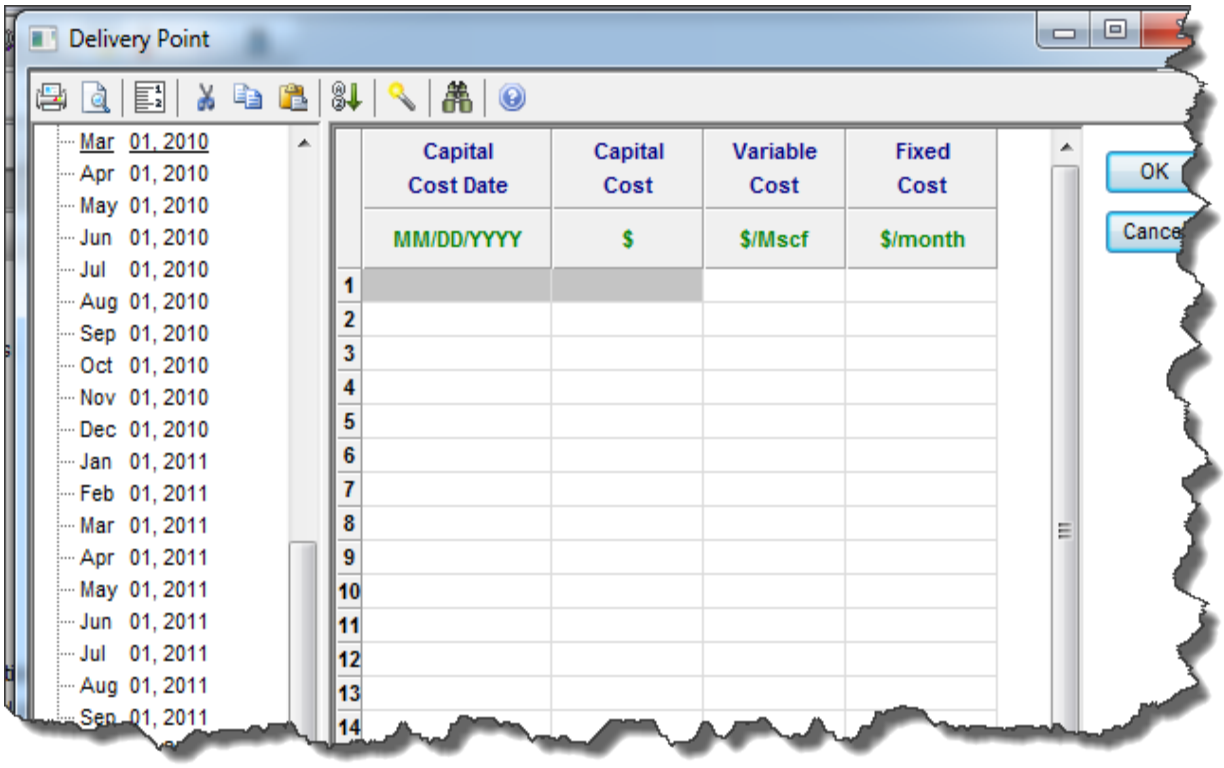
To enter default facility costs:

1. To apply default costs to all facilities of a specific type, click the **Default Facility Costs** tab.
    - (optional) enter the Capital Cost
    - (optional) enter the Monthly Operating Cost
    - (optional) enter the Variable Operating Cost



2. To apply costs to a facility individually, click the **Facilities or Wells** menu, select the respective facility, and enter the cost data in the applicable column of the editor.

   For wells, costs are entered in Well Editor > Well Inputs.



Note: Costs applied on an individual basis override costs entered in the Default Facility Costs tab.

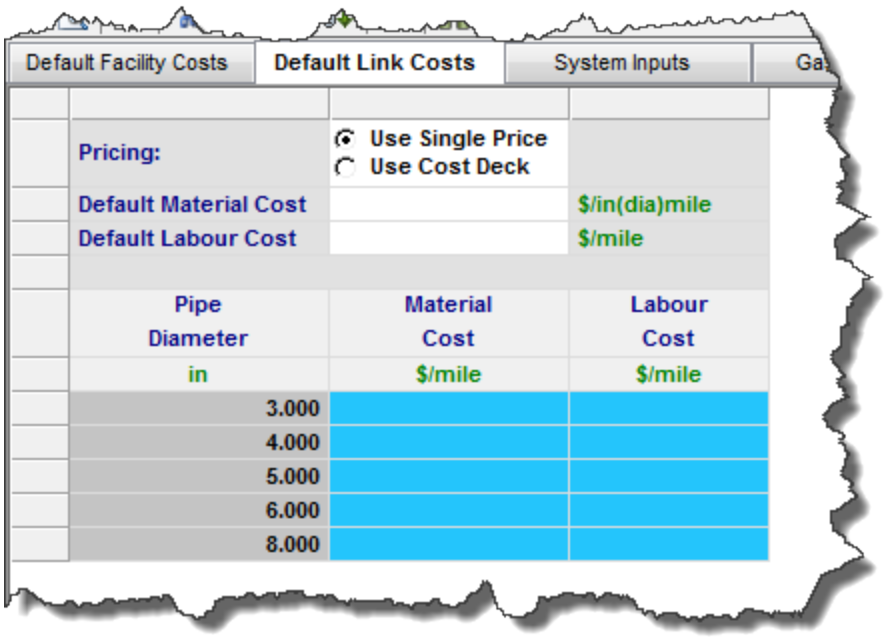
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Entering default link costs

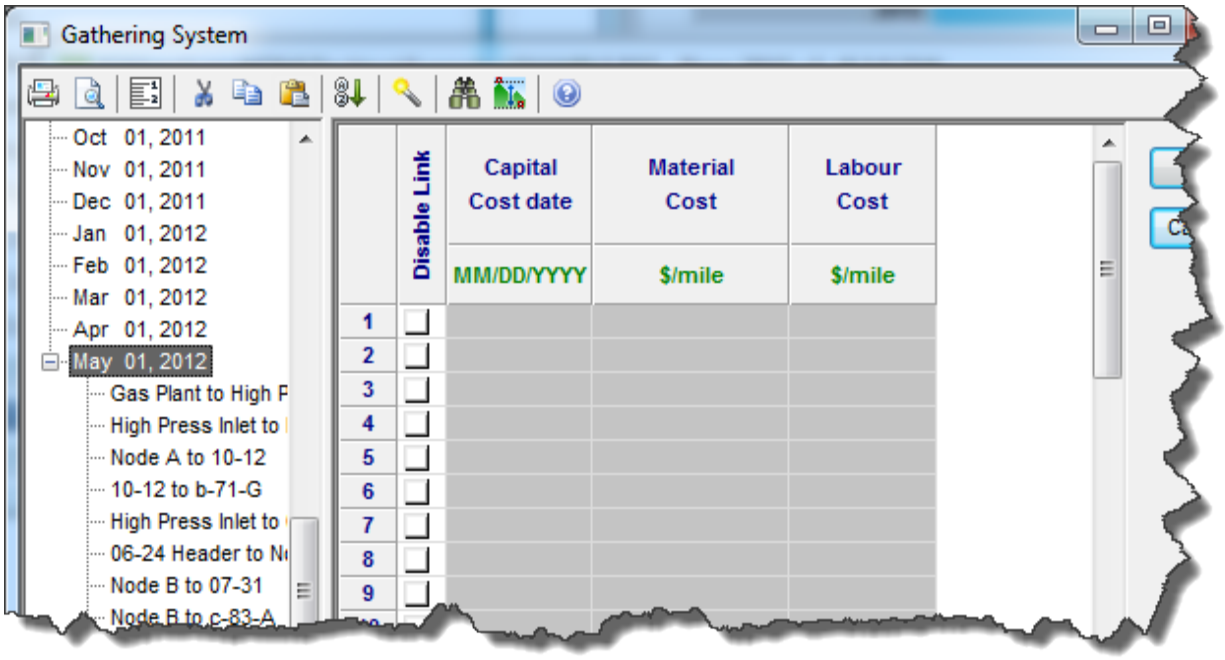
Default link costs include material and labor costs.

To enter default link costs:

1. To apply default link costs to all links, click the **Default Link Costs** tab:
   - Select **Use Single Price** to apply material and labor costs as default values (applicable to all pipeline diameters), then enter the **Default Material Cost** and the **Default Labour Cost**.
   - Or, select **Use Cost Deck** and enter the material and labor costs for specific link diameters in the Pipe Diameter table.



2. To apply link costs to individual links, click the **Pipelines** menu and select **GatheringSystem**. Enter the cost data in the applicable column of the editor (Material and / or Labour Cost, and Capital Cost Date).



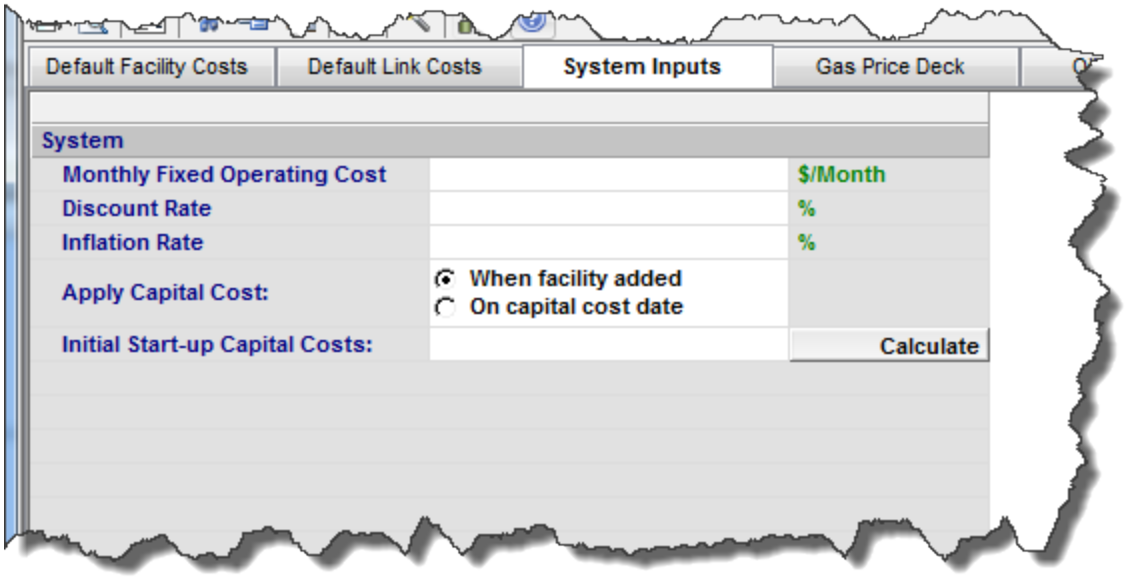
Note: Costs applied on an individual basis override costs entered in the Default Link Costs tab.

Entering system inputs

The System Inputs tab contains economic parameters that apply to the gathering system as a whole.

To enter system input data:

1. Click the **System Inputs** tab.



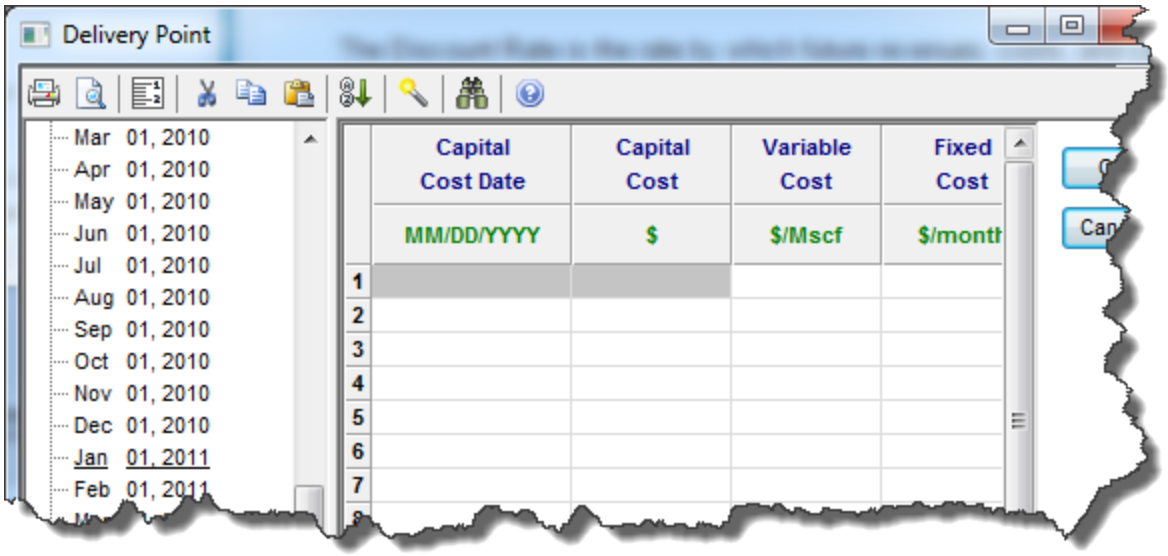
2. (Optional) Enter the **Monthly Fixed Operating Cost**.
3. (Optional) Enter the **Discount Rate** based on a percentage yearly basis.
4. (Optional) Enter the **Inflation Rate** on a yearly basis.

   Note: When an economics forecast is run, the equivalent monthly inflation rate is determined from the yearly rate.

5. To apply the capital cost when the facility is added to the model, select **When Facility Added** in the Apply Capital Cost field.

   The facility must be attached to a node to be included in the cost.

   Or, to apply the capital cost on the date specified in the respective Facilities editor in the Capital Cost Date column, select **On Capital Cost Date** in the Apply Capital Cost field.



6. To include capital costs of facilities that exist as of the gathering system start date, enter the **Initial Start-up Capital Costs**.

   Or, to automatically calculate total capital costs from values entered in the Default Facility Costs, Default Link Costs, and the Capital Cost column of each of the Facilities menu editors, click the **Calculate** button.

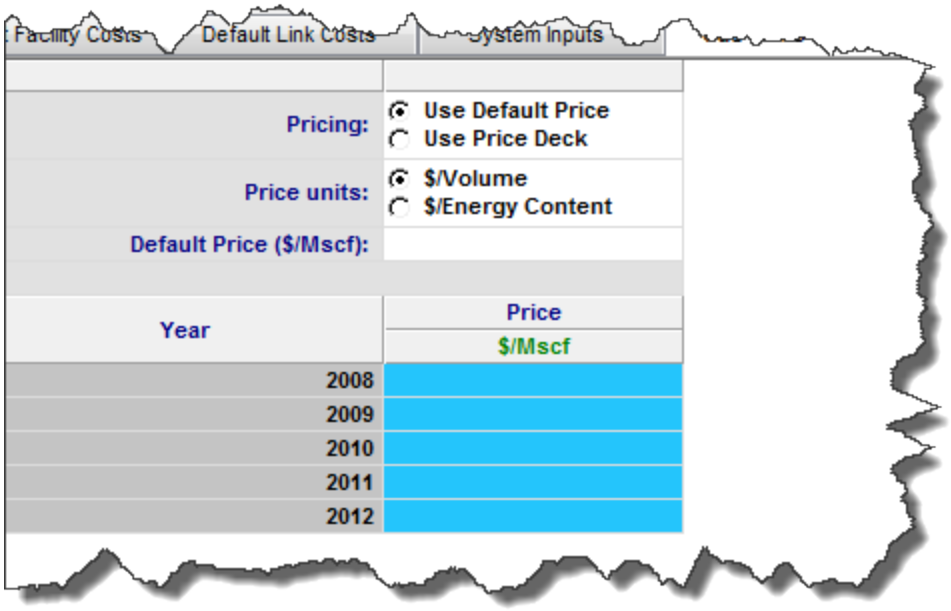
Entering gas price deck

To enter gas price deck data:

1. Click the **Gas Price Deck** tab.

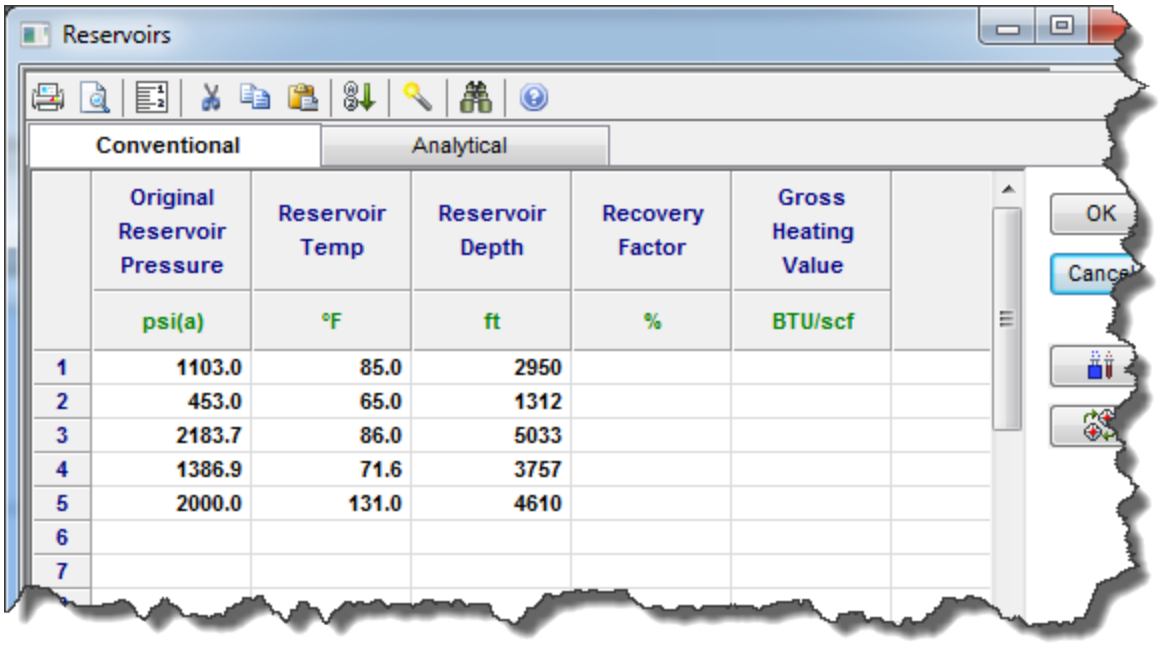
2. To use the same price for each forecast period, select **Use Default Price**.

   Or, click **Use Price Deck** and enter a price ($ / bbl) for each year of the forecast duration in the Year / Price table.



3. To define pricing on a volume basis of $ / Mcf ($ / 10^3m^3), select **$ / Volume**.

   Or, to define pricing based on the Gross Heating Value entered in the Reservoirs editor, select **$ / Energy Content**.



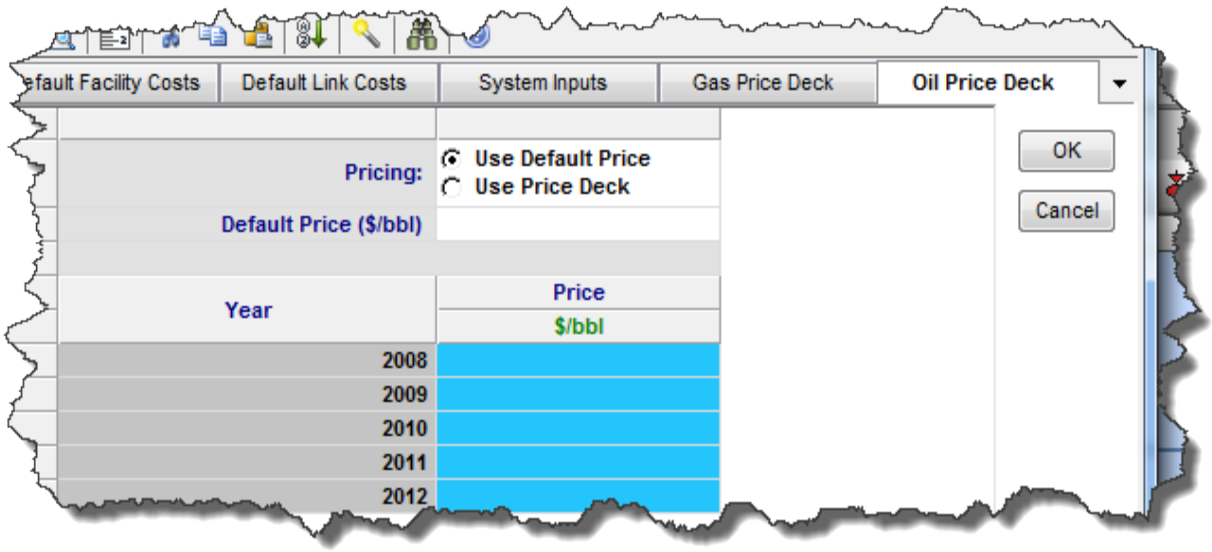
	Original Reservoir Pressure	Reservoir Temp	Reservoir Depth	Recovery Factor	Gross Heating Value
	psi(a)	°F	ft	%	BTU/scf
1	1103.0	85.0	2950		
2	453.0	65.0	1312		
3	2183.7	86.0	5033		
4	1386.9	71.6	3757		
5	2000.0	131.0	4610		
6					
7					

Entering oil price deck

To enter oil price deck data:

1. Click the **Oil Price Deck** tab.
2. To use the same price for each forecast period, select **Use Default Price**.

   Or, to apply a price for each year of the forecast duration in the Year / Price table, select **Use Price Deck**.

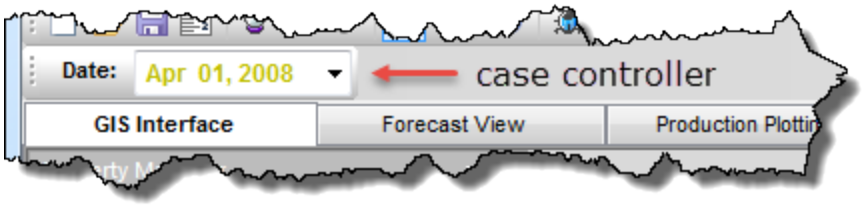


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Adding changes after building your model

Adding configurations

By default, any model additions, deletions, or changes apply to the current date shown in the case controller.



The case controller drop-down list displays the periods specified by the forecast duration field in the forecast view tab.

To add a configuration:

1. Select a date from the drop-down list in the case controller.
2. Make a change in your model.

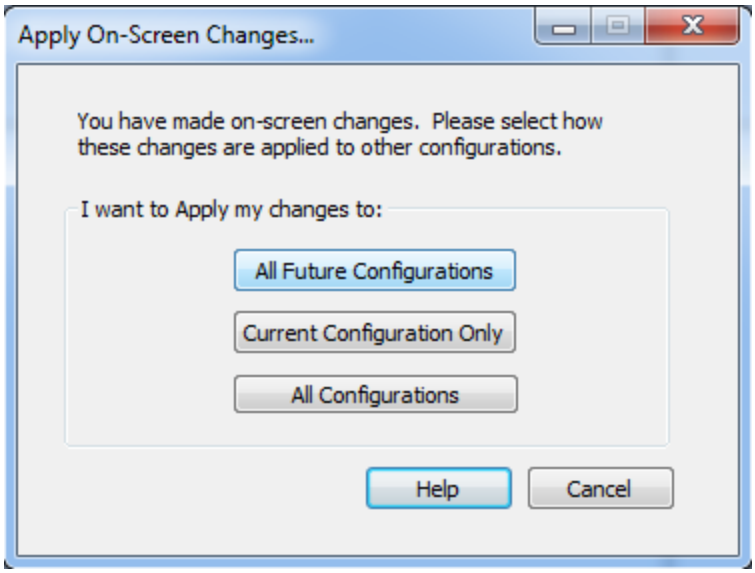
   Once you make a model change on a specific date, it is now a configuration date and it is highlighted in yellow in the case controller drop-down list. It is also highlighted in yellow font in the forecast view tab.

3. To finalize your changes, see applying configuration changes below.

Applying configuration changes

Gathering system changes are applied any time you make edits. For example, if you change a facility property from its editor, you are prompted to apply the change when you click elsewhere in the interface. Or, if you add or change a facility or link from the GIS Interface, and then open another tab, editor, or menu, you are prompted to apply your changes. You can also manually apply GIS-generated changes by clicking the Apply Changes icon in the GIS navigation toolbar. This icon is enabled when changes are made using the GIS. Once the changes are applied, the icon is disabled.

The Apply On-Screen Changes dialog box is displayed when any change is made to the gathering system.



To apply your changes, select one of the following:

- All Future Configurations — changes are applied to the currently selected date and all future configuration dates
- Current Configuration Only — changes are applied from the current configuration date up to, but not including, the next configuration date

  To revert a configuration change, select this case from the forecast view and then delete it
- All Configurations — changes are applied to past, present, and future configuration dates

Note: If you are not sure about which dates to apply your configuration changes to, we recommend using the schedule menu to manually select dates by facility type.

Managing configurations

You can manage configurations from:

- the forecast view tab
- the schedule menu

Forecast view tab

Using the forecast view tab, you can cut, copy, paste, and delete cases, and delete forecasts. You must run a new forecast after selecting one of these actions. For more information, see forecast view.

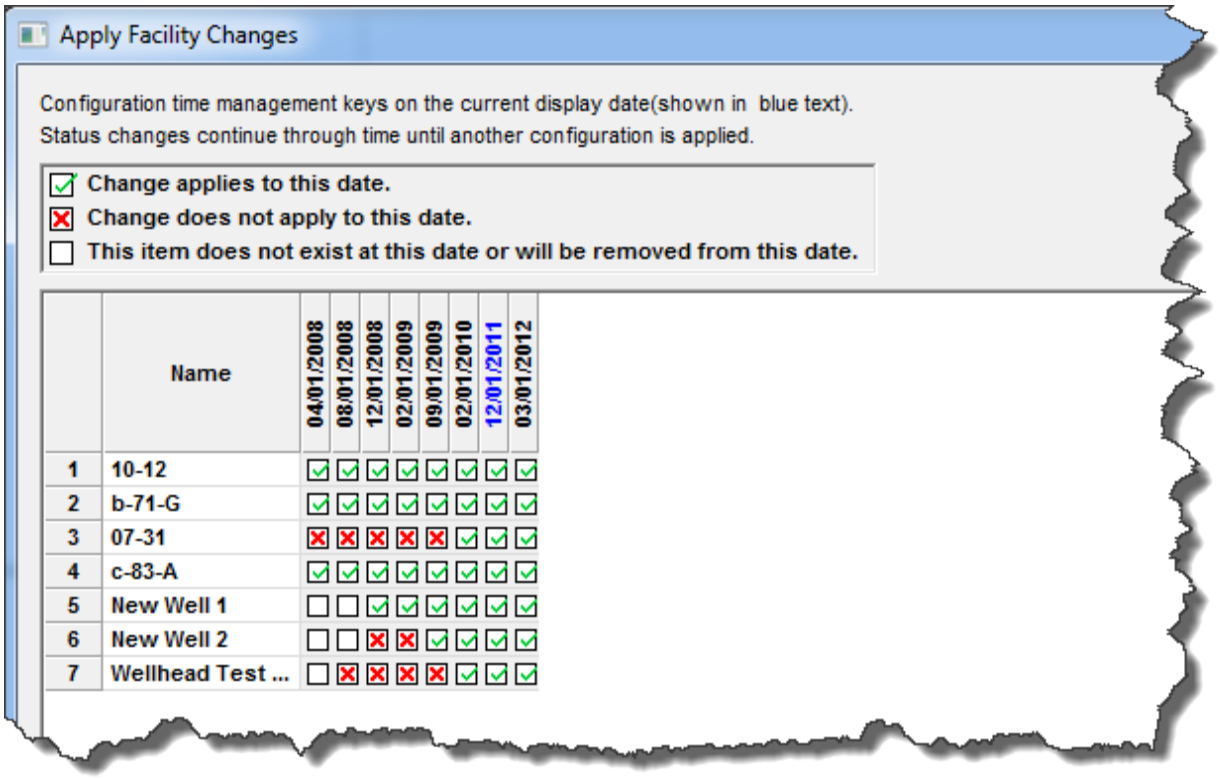
Schedule menu

Using the schedule menu, you can manually apply a configuration change to other configuration dates on an individual facility basis.

To manually apply a configuration change:

1. Click the **Schedule** menu and select a facility type.

   The Apply Facility Changes dialog box opens. Blank entries indicate the facility does not exist for a configuration date.



Note: The changes you are applying are determined by the configuration date selected in the case controller. This date is displayed in blue in the Apply Facility Changes dialog box.

2. For each of the facilities, determine how you want your change applied. Select:

   - ✓ — to apply your change to a configuration date
   - ✖ — to not apply your change to a configuration date
   - ☐ — to remove the facility as of a configuration date.

   Applied changes continue through time until another configuration (i.e., change) is applied.

3. Click **OK**.

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Common importing tasks

You can import: historical and current production data, analytical models, location files, reservoir and wellbore data, shapefiles, and image files.

For historical production data imports, see:

- Merak / Dwight file
- Harmony
- production data import

For current production data imports, see production data import.

For location data imports, see importing location text or Excel files.

For analytical model imports, see importing data from Harmony Enterprise.

For profile production imports, see importing profile production.

For shapefile imports, see importing a shapefile.

For image file imports, see importing an image file.

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Importing data from Harmony Enterprise

Harmony Enterprise™ data, including reservoir and wellbore specification data, can be imported into Piper.

To import data from Harmony Enterprise:

1. Click the **Import** menu and select **Harmony Enterprise (hmy2pip)**.
2. Select the Source Type (File is the default) and click **OK**.
3. Select a file to import.
4. Click the **Import** button.

   The selected data is imported into Piper, and can be viewed in the Well Editor.

Well data is imported, and includes:

- **GIS Location** — imports the well locations from the Harmony Enterprise file (if they exist).
- **Well Data** — imports some attributes from the Harmony Enterprise model. These attributes are used to create a conventional gas reservoir in Piper.
- **Calibration Data** — imports measured production and pressure data from a specified date in Harmony Enterprise. This data is used to validate that the Piper model matches field data through a process called calibration. For more information, see calibrating.
- **<Analytical Model>** — imports the analytical model into Piper. Also, an analytical reservoir is created in Piper and is associated with the well. The name of the model depends on the name used in the source Harmony Enterprise file.

When you import from Harmony Enterprise, all well attributes, including wellbore, reservoir properties, and locations are overwritten. If the location in Harmony Enterprise is null, locations in Piper are overwritten with null values.

Piper does not support the complex wellbores that are supported by Harmony Enterprise. If the wells in Harmony Enterprise are deviated or have horizontal segments, multiple tubing strings, or multiple casing strings, the wellbore configuration is simplified upon import into Piper. The simplification rules are:

Casing diameter import

- If there is only an open hole defined in Harmony, the open hole diameter is imported as the wellbore casing diameter.

- If there is a casing and open hole defined in Harmony, the casing is imported as the wellbore casing diameter.
- If there are multiple casing strings defined in Harmony, the casing with the lowest depth is imported as the wellbore casing diameter.
- If there is a liner defined in Harmony, the liner of lowest depth is imported as the wellbore casing diameter.

  Note: Casing diameters in Harmony Enterprise are saved to tubing diameters, and the flow-path is set to tubing.

Tubing diameter and depth import

- If there is more than one tubing defined, the tubing with the lowest depth is imported as the tubing diameter and EOT.
- If there is no tubing defined, the tubing diameter and EOT are left blank in Piper and require input from the user.

Deviation survey and horizontal wells

- When a wellbore deviates to an angle of greater than 50 degrees, the portion of the wellbore that is beyond 50 degrees is ignored.
- The EOT and MPP depth imported into Piper are the Measured Depth up to the point where the angle exceeds 50 degrees. Any liner segments that begin after the deviation exceeds 50 degrees are also ignored.
- The most recent wellbore profile defined in Harmony is always used to define the wellbore imported into Piper.

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Importing image files

Image files can be imported and layered on the map to provide more information on the surrounding area, for example lakes and rivers. Piper supports TIFF, JPEG, GIF, BMP, and PNG image files.

To import image files:

Note: You must have three known locations / coordinates (in latitude and longitude or UTM) for your image in order to import.

1. Click the **Import** menu and select > **Image File**.

   Or, click the () icon in the Property Manager and select **Add Image Layer**.

2. Select an image file to import.

   The Image Layer Setup dialog box opens and displays the selected image file on the right-side of the dialog box.

3. Set the three reference points for the image. For each reference point:

   - Scroll to a known location on your image, right-click at that point, and select **Set Point** to set the reference point.
   - A crosshair symbol is displayed at the clicked location. If an alternate location is required, click the symbol and drag it to the alternate location.

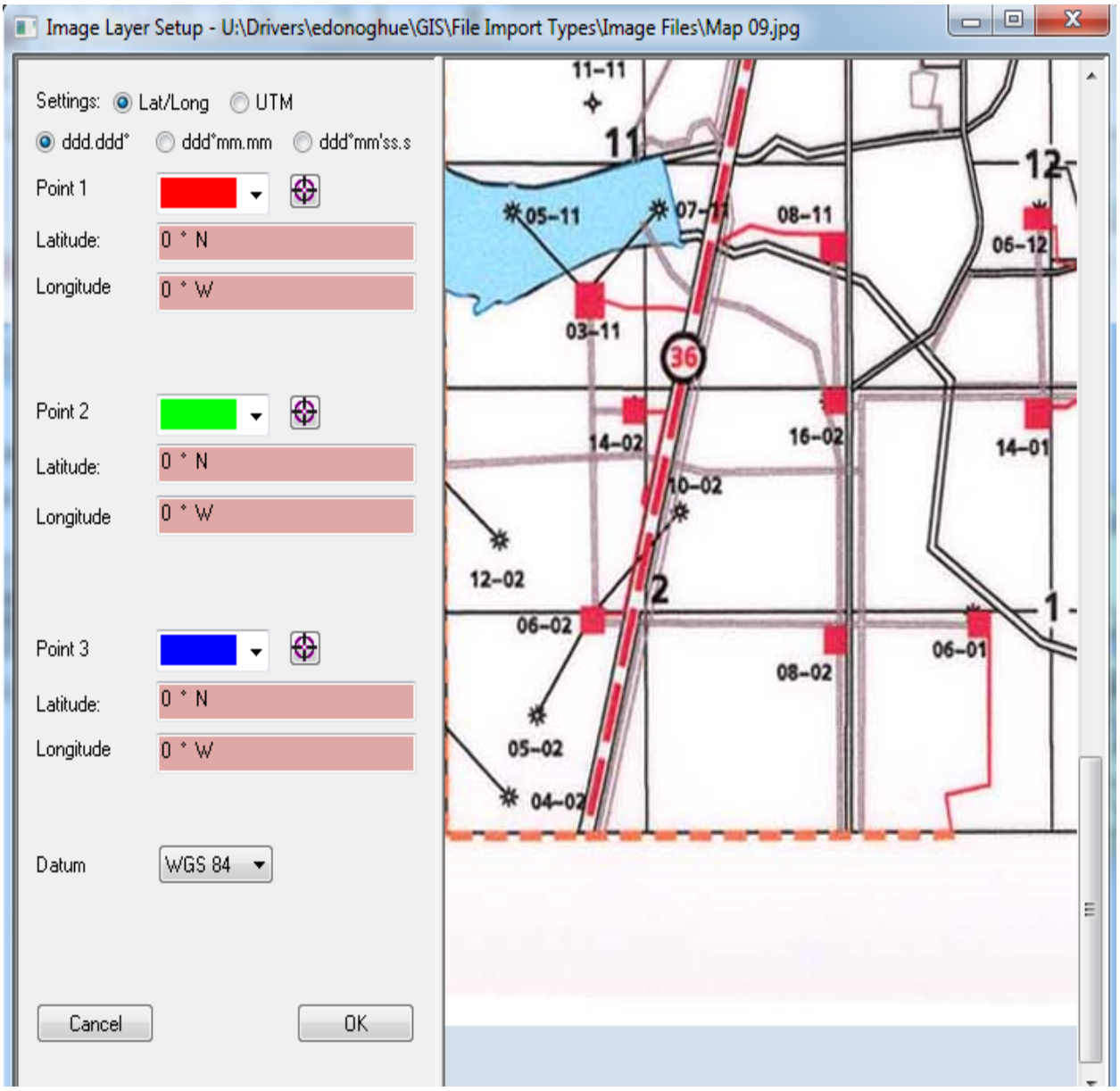
   We recommend selecting locations for the reference points that are at the outer extent of the image in order to avoid skewing.

4. Repeat step 3 for the remaining two reference points.

5. For the Settings (on the left-side), select **Lat / Long**, or **UTM** for the coordinate format of the reference points.

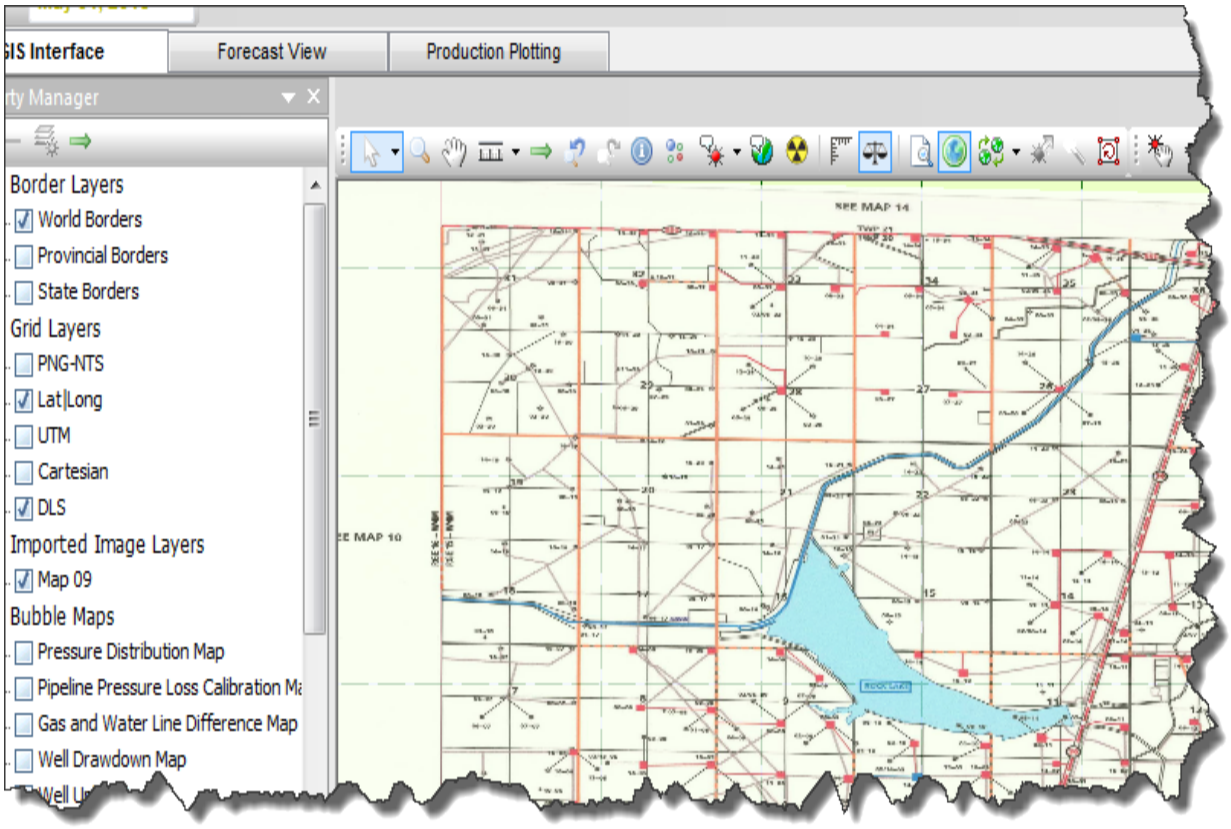
6. Enter the coordinates for the three reference points set in steps 3 and 4.

   Tip: To toggle the direction between N / S and E / W for latitude and longitude coordinates, press the minus key on your keyboard.



7. Select the **Datum** from the drop-down list and click **OK**.

   The map centers on the imported image.



If your image did not import correctly, right-click the image in the Property Manager and select Edit Image Layer. The Image Layer Setup dialog box opens and you can review and revise the data originally entered.

Importing Merak Dwight files

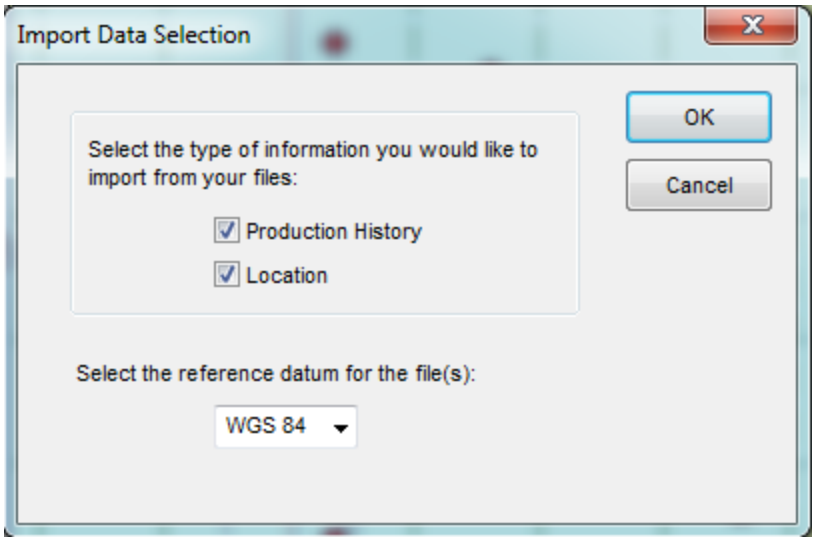
Merak and Dwight file types are commonly used in the oil & gas industry to store well information and historical production data. Merak files are a common format in Canada, and have the extension "mer". Dwight files are a common format in the United States, and have the extension "dp2".

Imported wells from a Merak or Dwight file are automatically located on-the map based on the latitude and longitude locations specified within the file. It is not necessary to add wells to the model before importing a Merak or Dwight file.

To import Merak (.mer) or Dwight (.db2) files:

1. Click the **Import** menu and select **Merak / Dwight File**.
2. Select a file for import.

   The Import Data Selection dialog box opens.



3. Select the data to import from the file (production history and / or location).
4. Select your reference datum from the drop-down list and click **OK**.

   The map centers around the imported wells.

   Imported data appears in the Unresolved Production History Wells pane in the Production Plotting tab. Once the historical production data has been imported, well names must be matched to the corresponding well names created in Piper. See production plotting for more information.

Importing production data

In Piper, you can import historical and current production data.

Historical data is used to make sure that model forecasts align with historical decline trends.

Current production data is used for model calibration by comparing measured rates and pressures against calculated rates and pressures. We recommend using production data that was obtained from a point in time when field production was stable.

To import production data:

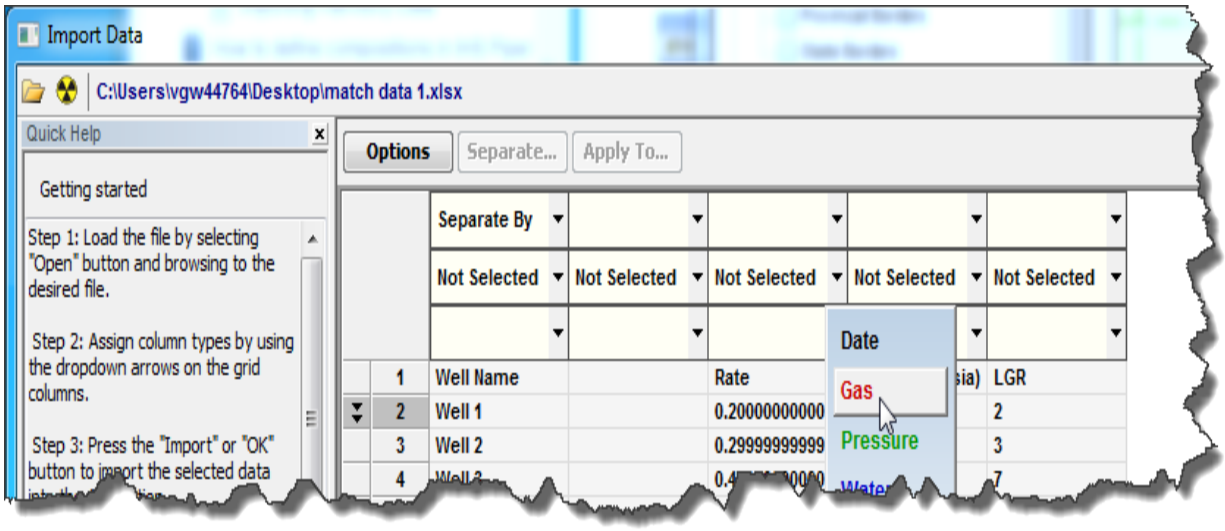
1. Click the **Import** menu and select **Production Import (Text or Excel)**, and then select from these options:
    - **Current Production (Text or Excel)**
    - Or, **Historical Production (Text or Excel)**
2. Select a file to import and then click **Open**.

    The Import Data dialog box opens.

    At a minimum, the following data needs to be imported for historical or current production data.

	Separate By	Time (daily or monthly)	Gas / Oil / Water (rate, volume data or LGR)	Pressure (gas, oil, or water line data)
Historical	✓	✓	✓	×
Current	✓	×	✓	✓

3. Select the columns that contain the data for import from the drop-down lists in the table.



4. Click **OK**.

   Imported historical production data appears in the Unresolved Production History Wells pane in the Production Plotting tab. Once the historical production data has been imported, well names must be matched to the corresponding well names created in Piper. See production plotting for more information.

   Imported current production data can be found in the Well Editor > Well Deliverability pane (rates) and Well Editor > Well Options pane (pressures).

5. Review the imported data for technical accuracy.

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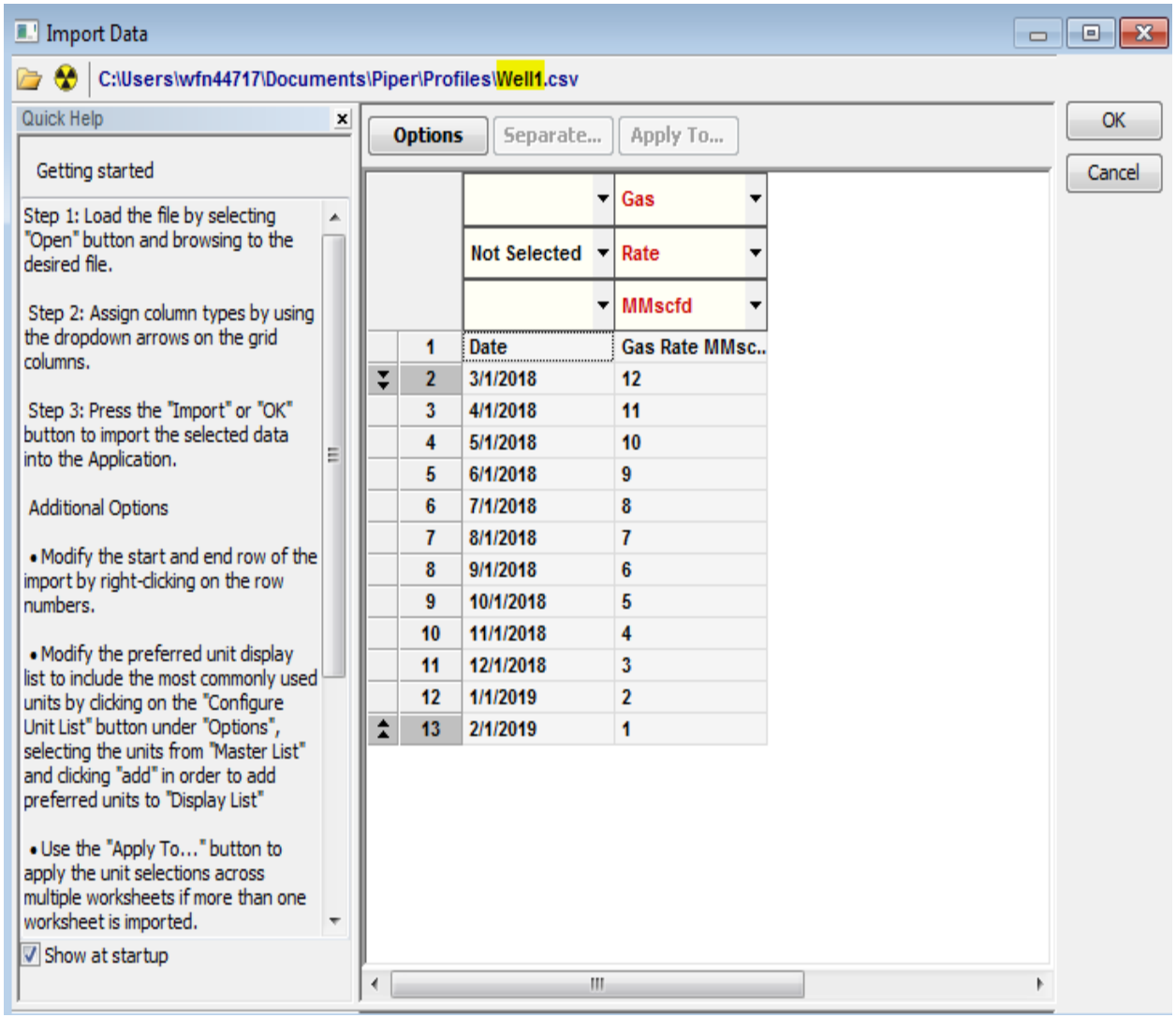
Importing profile production

Profiles are used when you want to import or manually enter gas or fluid rates.

To import profile production:

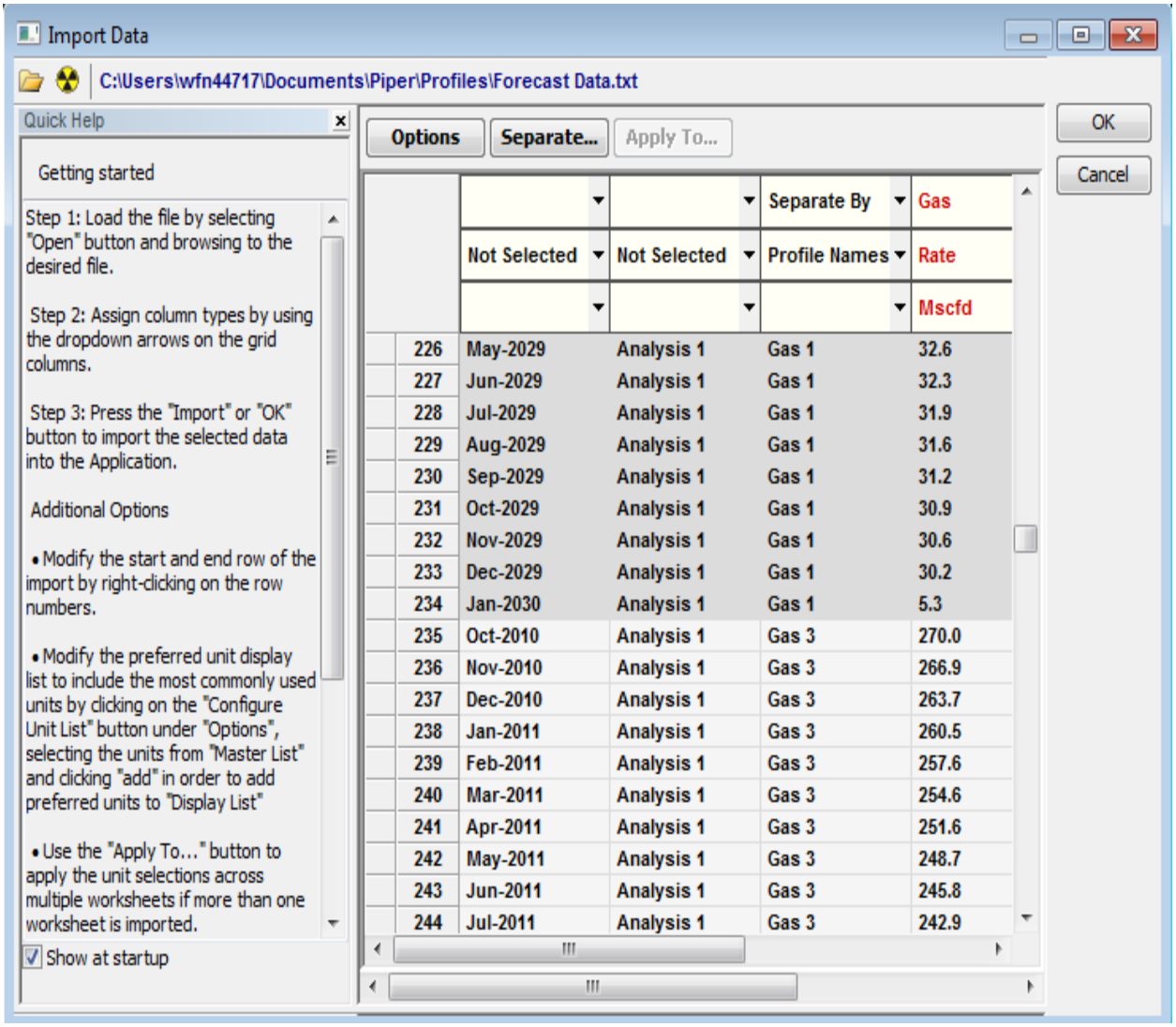
1. Click the **Import** menu and select **Profile Production Import (Text or Excel)**.
2. Browse to the file you want to use (.csv, .txt, .xlsx, xls).
3. In the Import Data dialog box, select the columns you want to import.

   Single profiles can be imported, and you can select the fluid and unit type for columns. (The file name is used to set the profile name.)

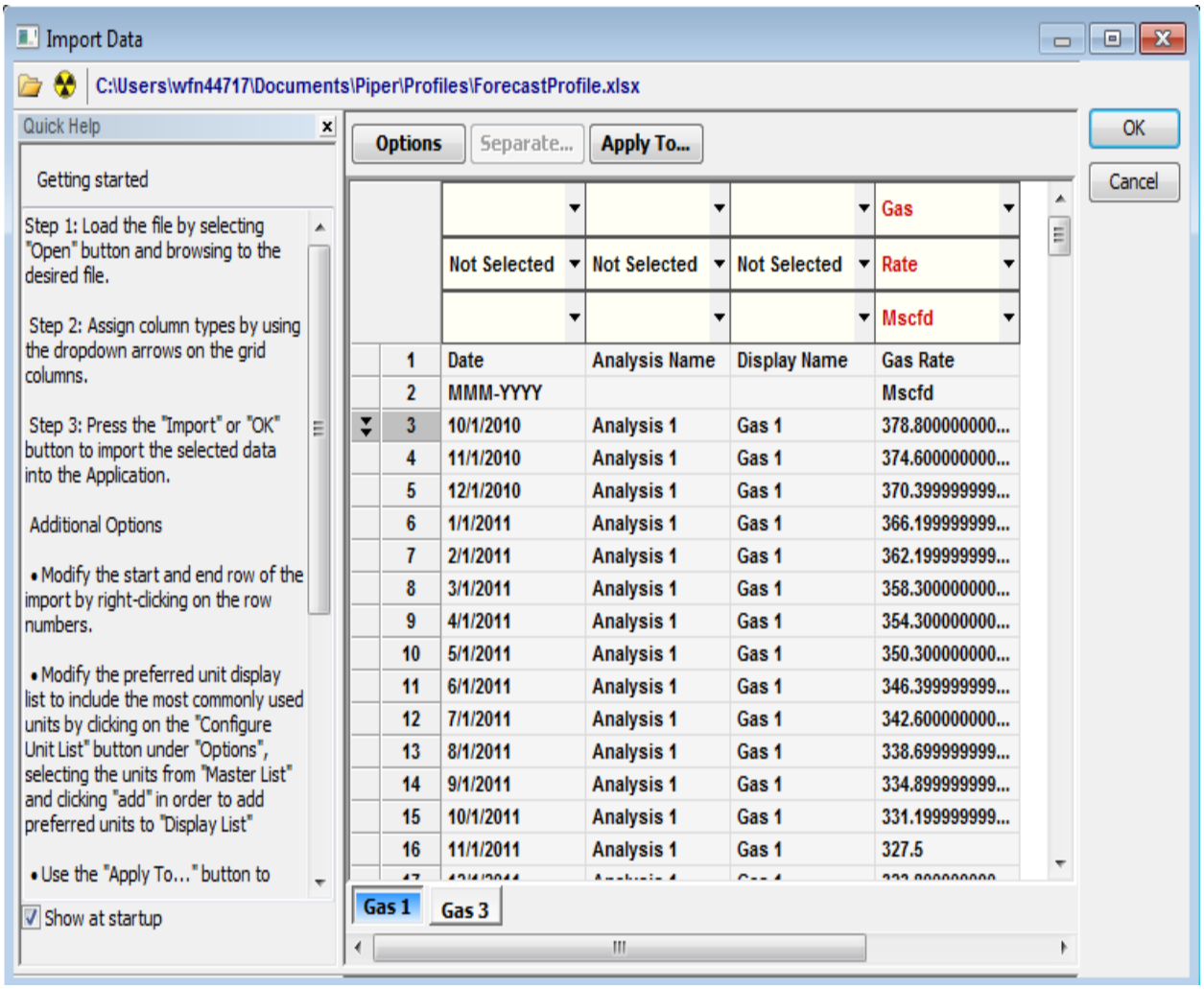


Multiple profiles can also be imported from a single file in one of two formats.

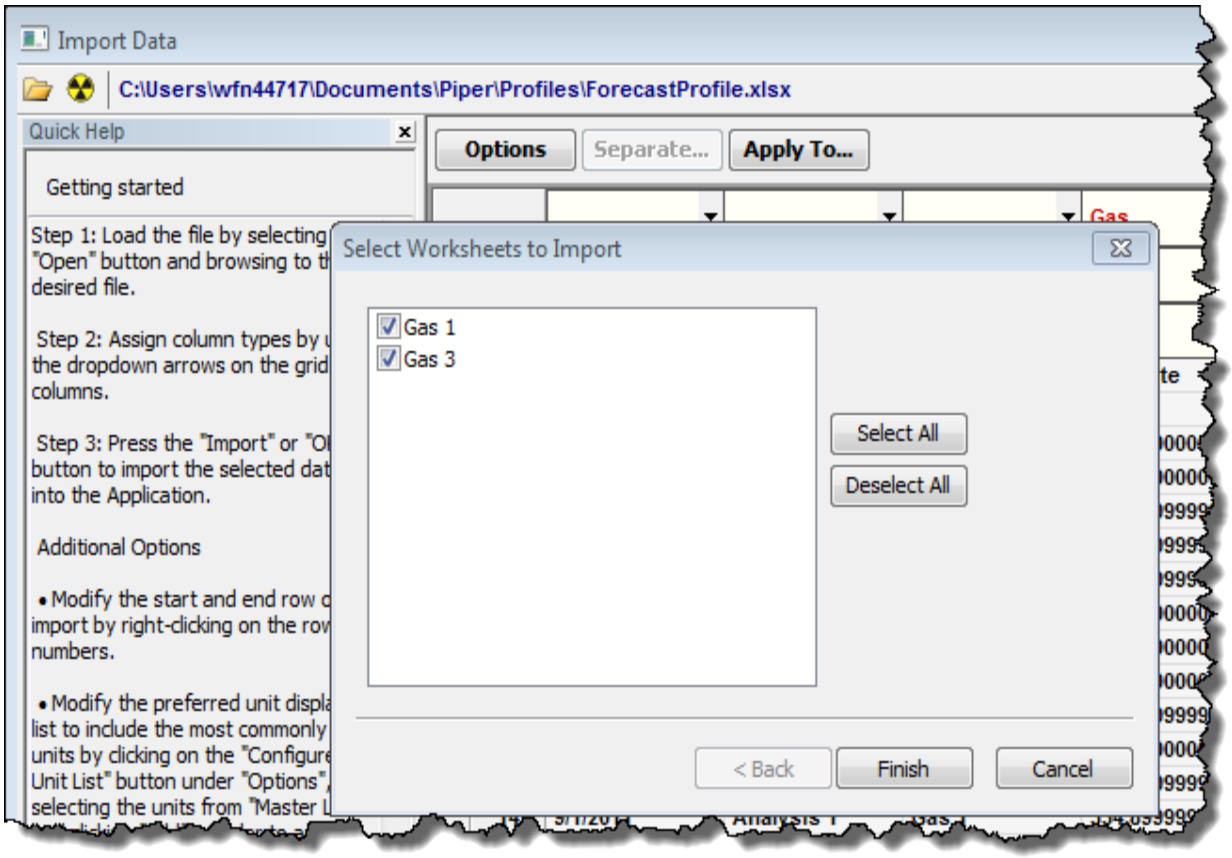
i.) You can select a profile name (included in the data) for one of your columns by selecting the **Separate By** option.



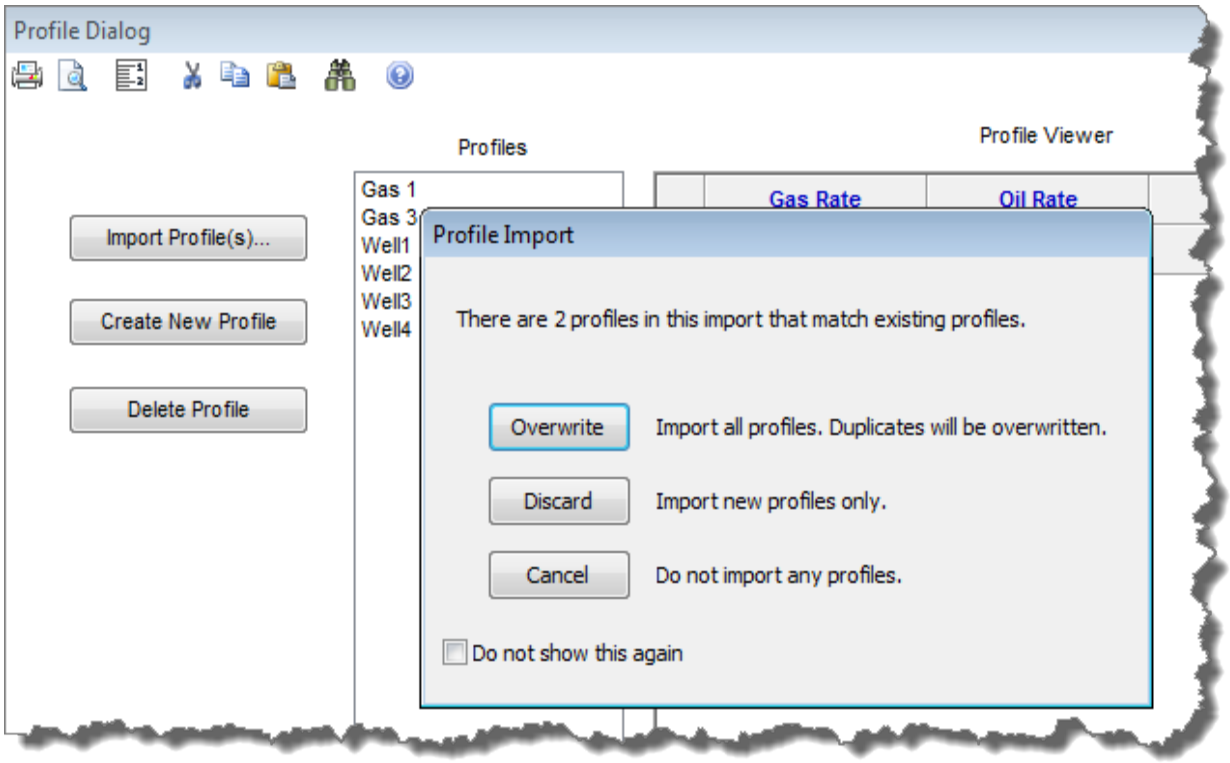
ii.) You can also separate profiles in tabs with an Excel file. If the format is identical in all tabs, you can click the **Apply To** button to apply the format once, and it is copied to all tabs.



When multiple profiles are mapped, you can confirm your selections prior to importing the file by clicking the **Finish** button.



When the profile name exactly matches an existing profile, you are given an option to over-write the existing profile, or discard the imported one. (You can set your default behavior for importing profiles by clicking the **Properties** menu and selecting **Customize**, **Recent File Options**.)



Or, click **Create New Profile** and:

a. Enter a **Profile Name** in the Profile Name Editor dialog box.

When creating profiles for profile wells, profiles are typically associated with a well grouping which can be used as the profile name. However, if each well maintains a separate profile, enter the name of the selected well as set in the Well Name column.

b. Click **OK**.

c. Enter expected gas, oil and water rates as applicable.

- When creating profiles for profile wells, enter rates for each period of your forecast duration in the **Profile Viewer** grid. Rates are based on monthly or daily averages.
- When creating profiles for gas lift, profiles are defined on a period basis. For example, to define the gas lift volumes for 12 months, 12 period volumes need to be defined for the profile.

The Profile Viewer grid is populated with the imported or entered rates.

4. Click **OK**.

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Importing shapefiles

Shapefiles can define underlying topography, culture, pipeline maps, or well locations. Shapefiles can be used to trace out the locations of pipelines, wells, and facilities, or to locate nodes to reflect the contours of elevation changes. Some imported shapefiles can also be converted to facilities or links directly. For more information on converting shapefiles to facilities or links, see adding facilities from a shapefile or adding links from a shapefile.

Note: Currently the only supported projection for importing shapefiles is the Mercator projection and the locations must be in geographical coordinates (i.e., latitude and longitude in decimal degrees). For example, state plane projections are not supported at this time.

To import a shapefile:

1. Click the **Import** menu and select **Shapefile**.

   Or, click the **Add Layer** icon () in the Property Manager and select **Add Shapefile Layer**.

2. Select a shapefile to import and then click **Open**.

   The imported shapefile is listed under the Imported Shapefile Layers category in the Property Manager Layers pane.

   See shapefile layers for more information on shapefiles,

Importing location text / Excel files

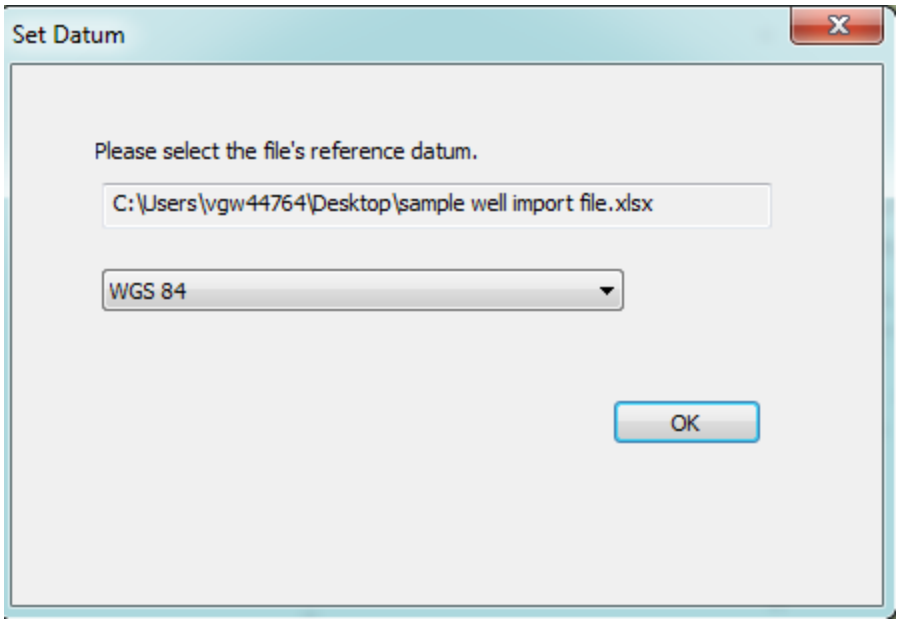
To import location text or Excel files:

1. Click the **Import** menu and select> **Location Text / Excel File** > **Well Import**.

   Or, click the **Import** menu and select> **Location Text / Excel File** > **Node Import**.

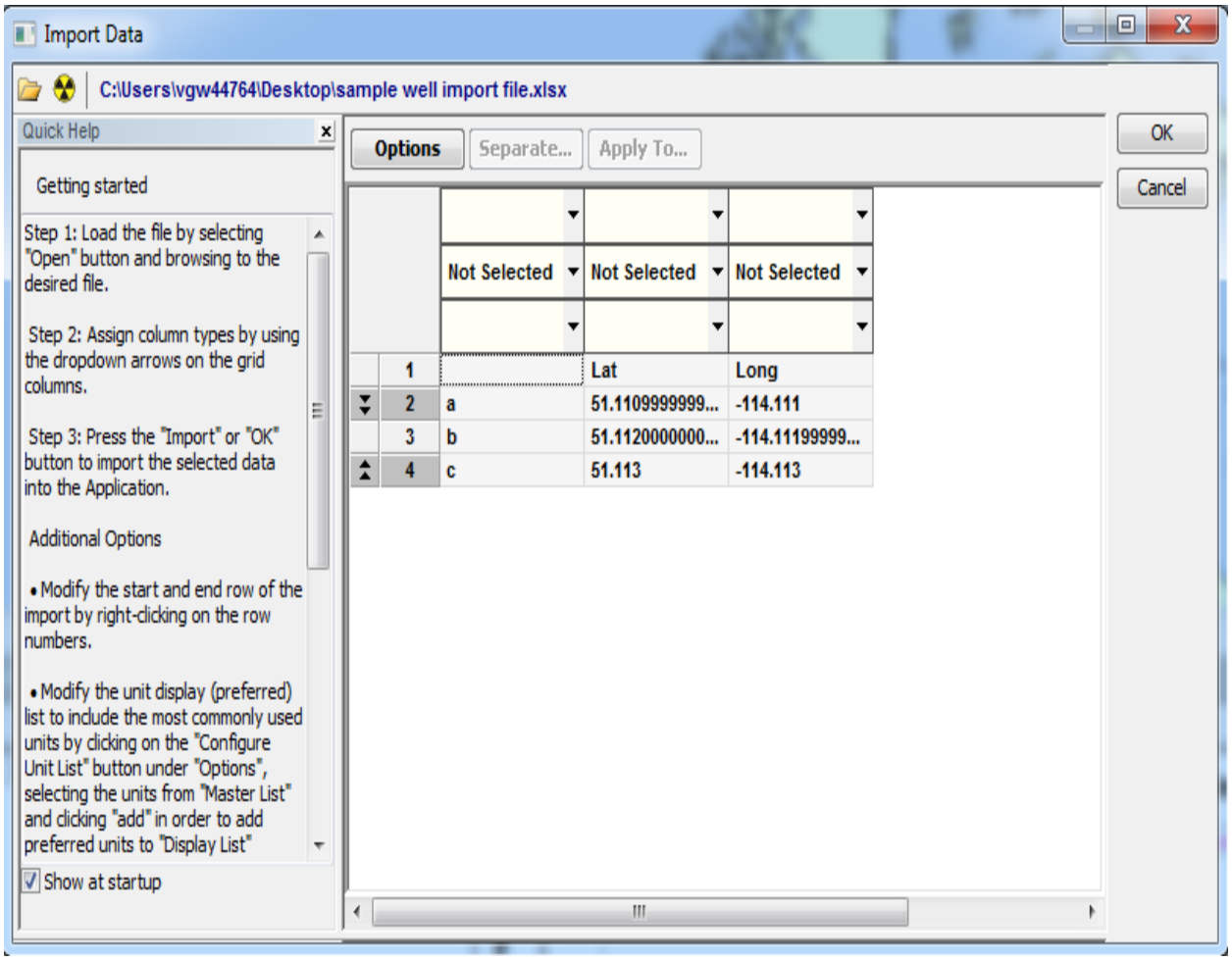
2. Select a location text or Excel file.

   The Set Datum dialog box opens.



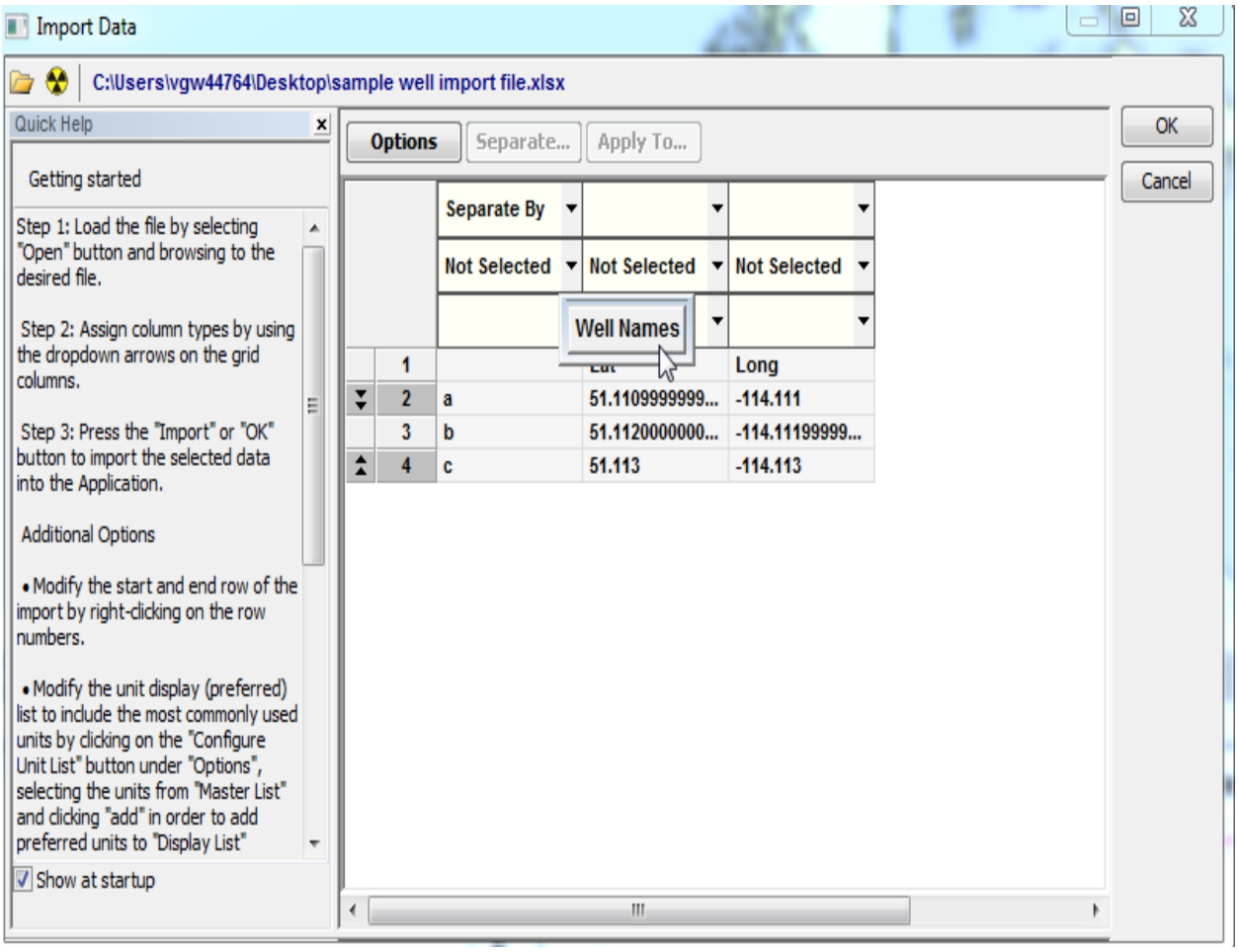
3. Select the applicable datum from the drop-down list and click **OK**.

   The Import Data dialog box opens with your unassigned data.



4. Select the data for import using the drop-down arrows in the columns of the table.

   At a minimum, you need to assign **Separate By** and **Surface Location** (latitude and longitude) information.



5. Click **OK**.

   The wells or nodes display on the map at their locations.

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Creating a SQL database for Piper

If you want to use SQL for your Piper data, you need to follow these two steps:

1. Create the database.
2. Connect from Piper to the database.

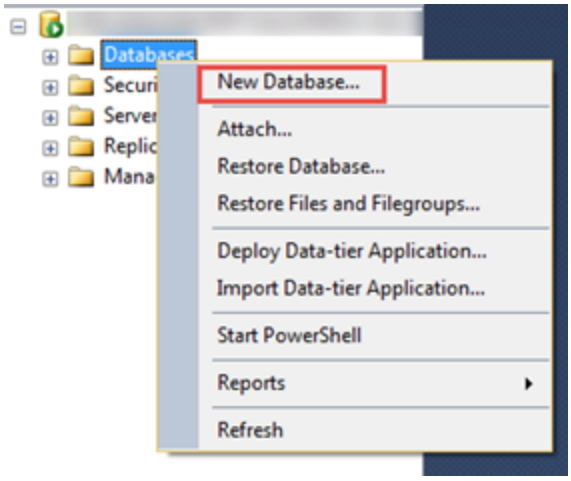
Creating the Piper SQL database

To create the Piper SQL database:

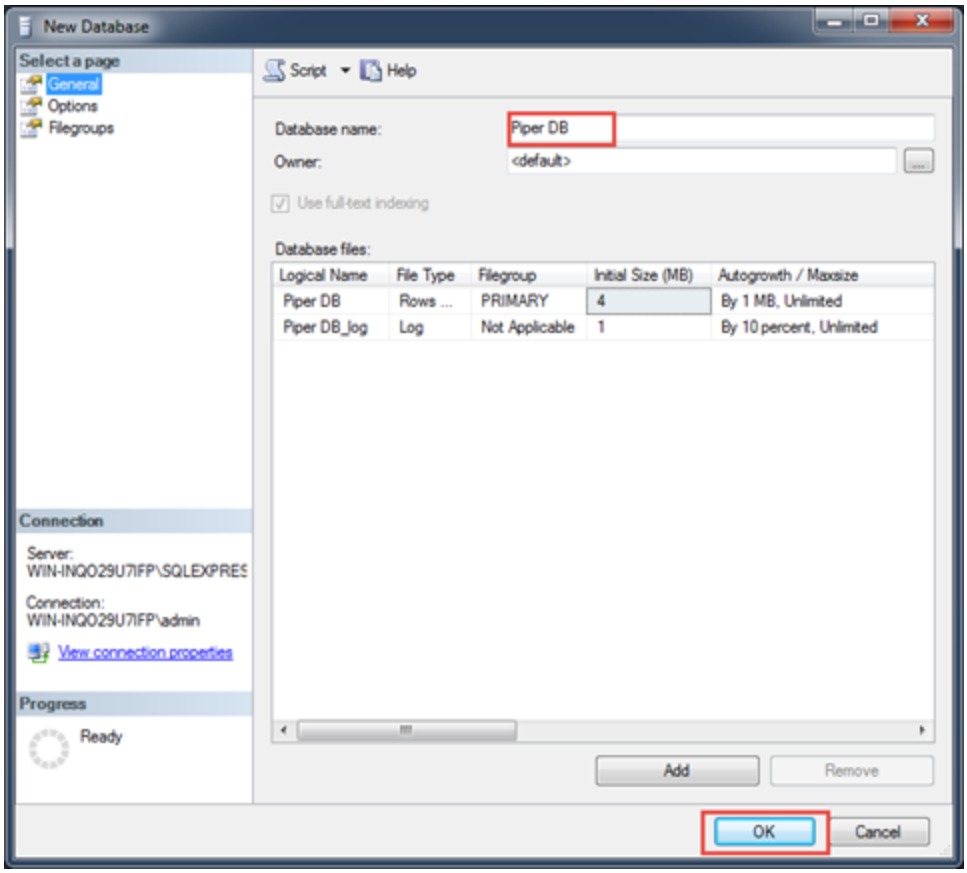
1. Install Piper.
2. Install SQL.
3. Launch SQL and connect to the SQL server.



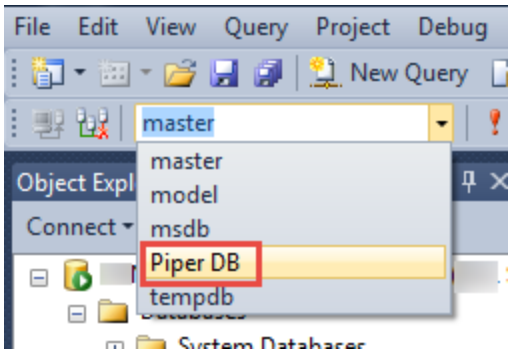
4. In the left-side SQL pane, right-click the **Databases** folder and select **New Database**.



5. Type a name for your database and click **OK**.



6. Click **New Query**, and change the query database to point to the database you named.



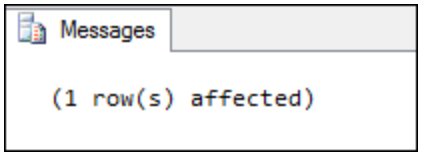
7. Navigate to the Piper MS SQL folder: C:\Program Files (x86)\IHS Markit\Piper 2018.1\Database\MS SQL.

8. Select the “P32MSSQLCreate.sql” file, and either drag it to the SQL query window, or double-click the file.

   This creates a new query tab in SQL.

9. Select the query window to ensure it is active, and then press **F5** to run the query.

If successful, the following message is displayed in the Messages pane.

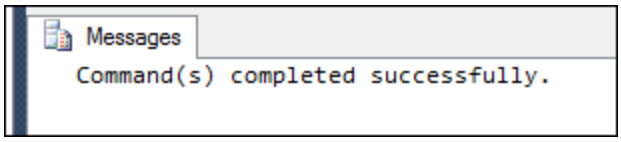


10. Select the Piper MS SQL folder again.
11. Select the “P32MSSQLProcs.sql” file, and either drag it to the SQL query window, or double-click it.

    This creates a new query tab in SQL.

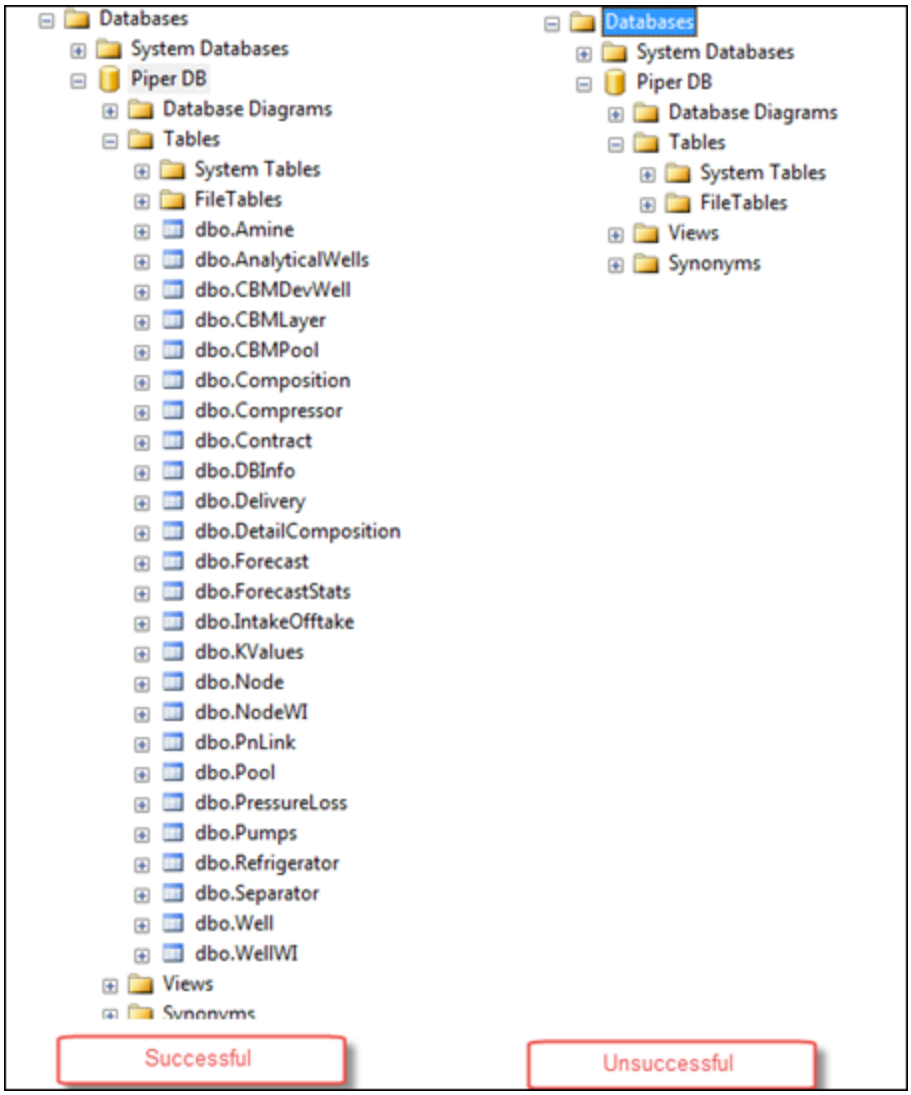
12. Select the query window to ensure it is active, and then press **F5** to run the query.

    If successful, the following message is displayed in the Messages pane.



13. In SQL, in the left-side pane, expand the Piper DB node, then the Tables node.

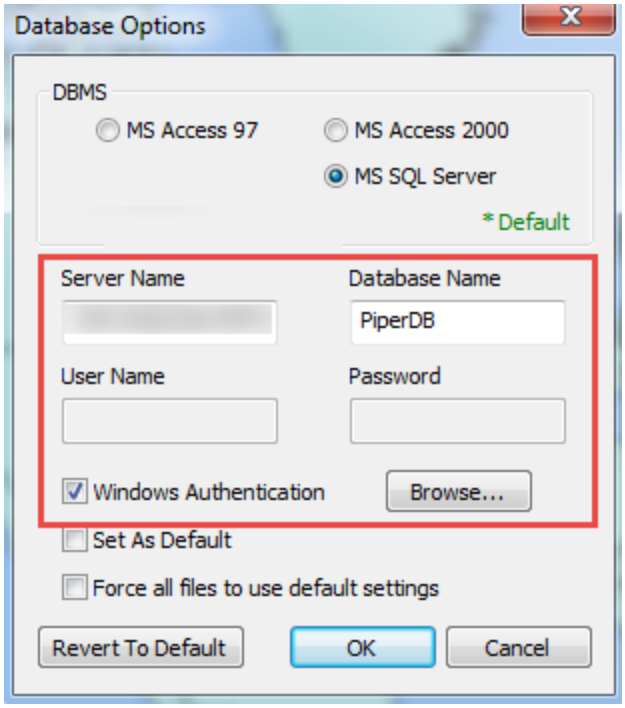
    If successful, a list of tables is displayed. If unsuccessful, only the default System and File Tables folders are displayed.


Databases
System Databases
Piper DB
Database Diagrams
Tables
System Tables
FileTables
dbo.Amine
dbo.AnalyticalWells
dbo.CBMDevWell
dbo.CBMLayer
dbo.CBMPool
dbo.Composition
dbo.Compressor
dbo.Contract
dbo.DBInfo
dbo.Delivery
dbo.DetailComposition
dbo.Forecast
dbo.ForecastStats
dbo.IntakeOfftake
dbo.KValues
dbo.Node
dbo.NodeWI
dbo.PnLink
dbo.Pool
dbo.PressureLoss
dbo.Pumps
dbo.Refrigerator
dbo.Separator
dbo.Well
dbo.WellWI
Views
Synonyms
Successful
Databases
System Databases
Piper DB
Database Diagrams
Tables
System Tables
FileTables
Views
Synonyms
Unsuccessful

Connecting to the SQL database via Piper

To connect to the SQL database via Piper:

1. Launch Piper.
2. Click **New Project** and select a viewing option (i.e., GIS Mode or Cartesian Mode).
3. Click the **Properties** menu and select **Database**.
4. Select **MS SQL Server**.
5. Enter the information to connect to the Database and click **OK**.



If no errors appear after clicking OK, the connection was successful.

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Printing

The following print functionality is available:

- printing a map
- printing all facilities on a map
- using multiple print configurations

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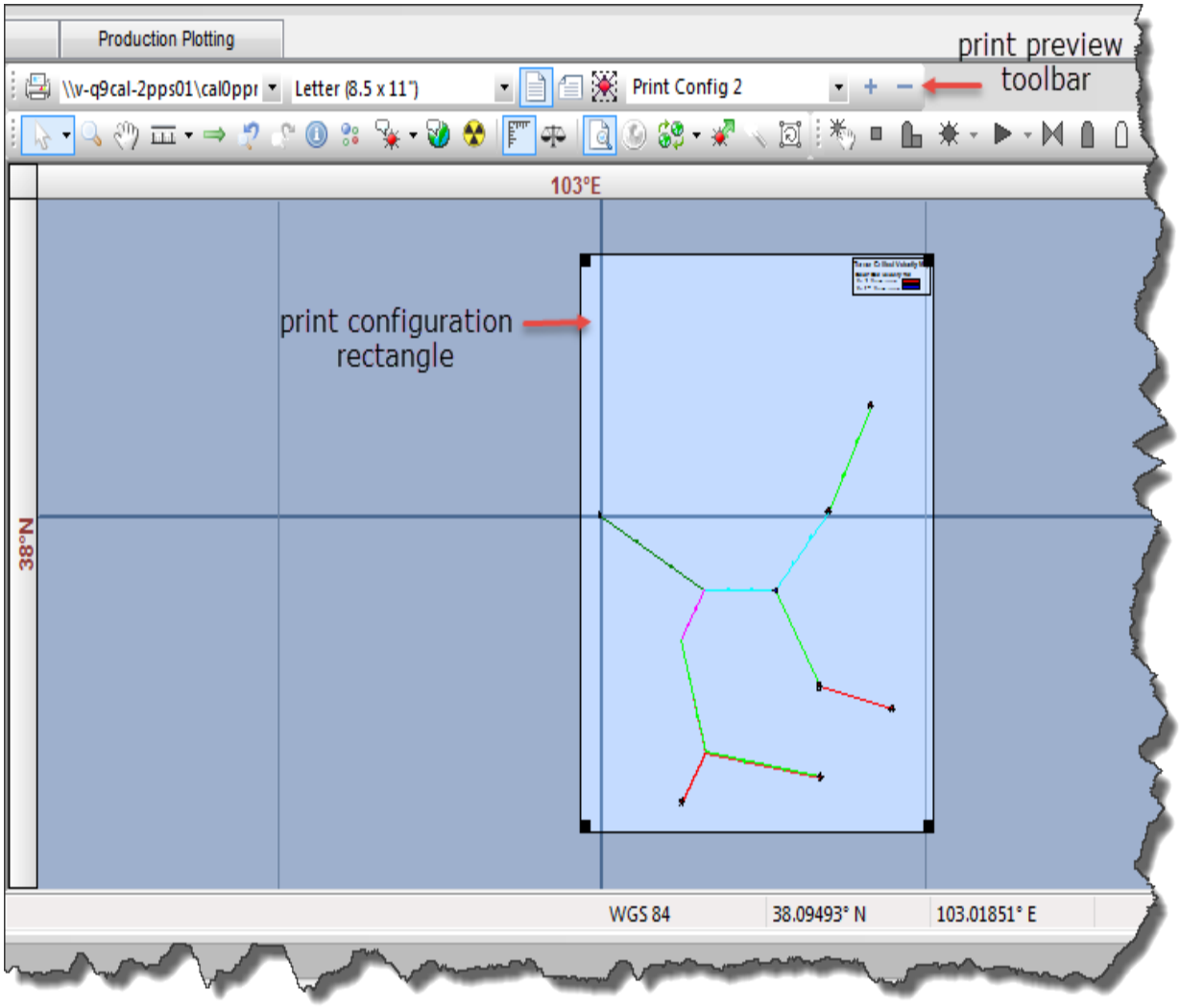
Printing a map

To print items on the GIS map, you need to create a print configuration in print preview mode.

To print a map:

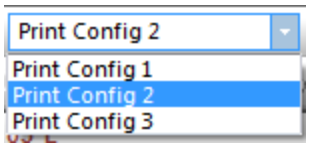
1. Click the **GIS Interface** tab.
2. Click the **Print Preview Mode** icon ( ) on the GIS navigation toolbar.

   The print preview toolbar is displayed and a print configuration rectangle is displayed on the map. This rectangle represents the default page size for the default printer.

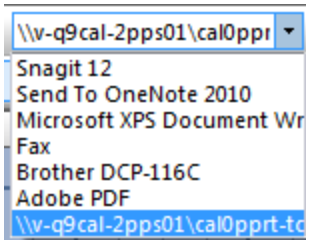


Note: Map items may shift when you click the print preview icon. You can adjust the print preview area so that these items print correctly. Resize the rectangle by grabbing any corner and dragging it (the aspect ratio of the page is maintained).

3. Select a print configuration from the drop-down list.

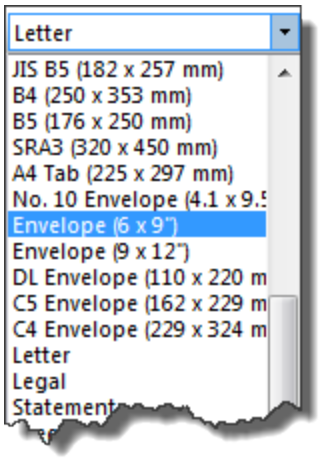


4. To change your printer, click the printer drop-down list and select a new printer. (The page size changes to that printer's default page size, and the print preview rectangle resizes as well.)



5. To change your page-size setting, click the page format drop-down list and select a page size.

   Page sizes are set by printer properties, they are not set in Piper.



6. To change your page orientation, click the **Portrait** icon (), or **Landscape** icon ().

   Note: Changing settings in steps 3 - 5 automatically resizes the print preview rectangle.

7. Click the **Print** icon ().

8. To exit print preview mode, click the **Print Preview Mode** icon.

   All print settings are saved.

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Printing all facilities on a map

A print configuration rectangle can be resized to fit the entire gathering system model.

To fit a print configuration:

1. Click the **GIS Interface** tab.
2. Click the **Print Preview Mode** icon () on the GIS navigation toolbar.
3. Click the **Reset Print Region to All Facilities** icon ().

   All facilities are included within the bounds of the print configuration rectangle while preserving the page size and aspect ratio.

   If map items such as bubble map legends, or annotations lie outside the print configuration rectangle, drag-and-drop them to lie within the rectangle boundaries.

4. Print the configuration; see printing a map.
5. To exit print preview mode, click the **Print Preview Mode** icon.

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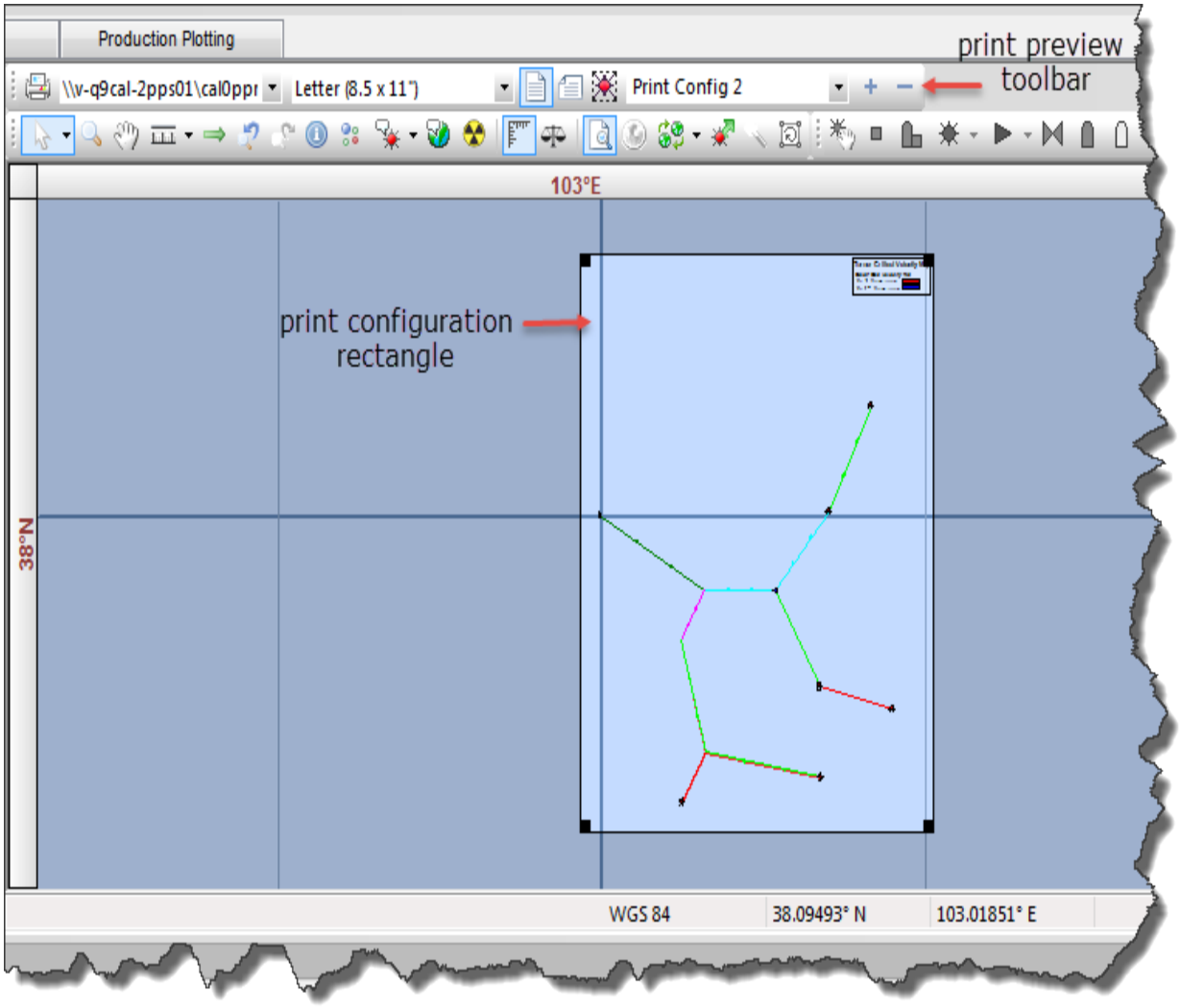
Using multiple print configurations

You can create multiple configurations for printing different areas of the GIS map with different settings. You can then select a print configuration and the map will zoom to the corresponding area.

To add, remove, or rename a configuration:

1. Click the **GIS Interface** tab.
2. Click the **Print Preview Mode** icon ( ) on the GIS navigation toolbar.

   The print preview toolbar is displayed and a print configuration rectangle is displayed on the map.



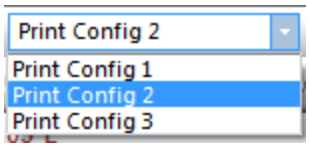
3. To add a print configuration, click the  icon.

   A new configuration based on the settings of the previously selected configuration (e.g., paper size, printer, etc.) is created. You can change these settings by following steps 3 - 5 in printing a map.

4. To remove a print configuration, click the  icon.

   The next print configuration in the list is automatically selected and the map zooms to that area.

5. To rename a print configuration, click within the print configuration drop-down list and type in a new name. Your edits are instantly applied.



6. Print the configuration; see printing a map

7. To exit print preview mode, click the **Print Preview Mode** icon.

   All print settings are retained on exit.

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User interface

Piper has these important components:

- menus
- toolbars
- case controller
- GIS interface tab
- forecast view tab
- production plotting tab
- editors

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Menus

Piper has the following menu items, but the menu changes depending on the tab you select. For example, if you click the Production Plotting tab, the menu items change.

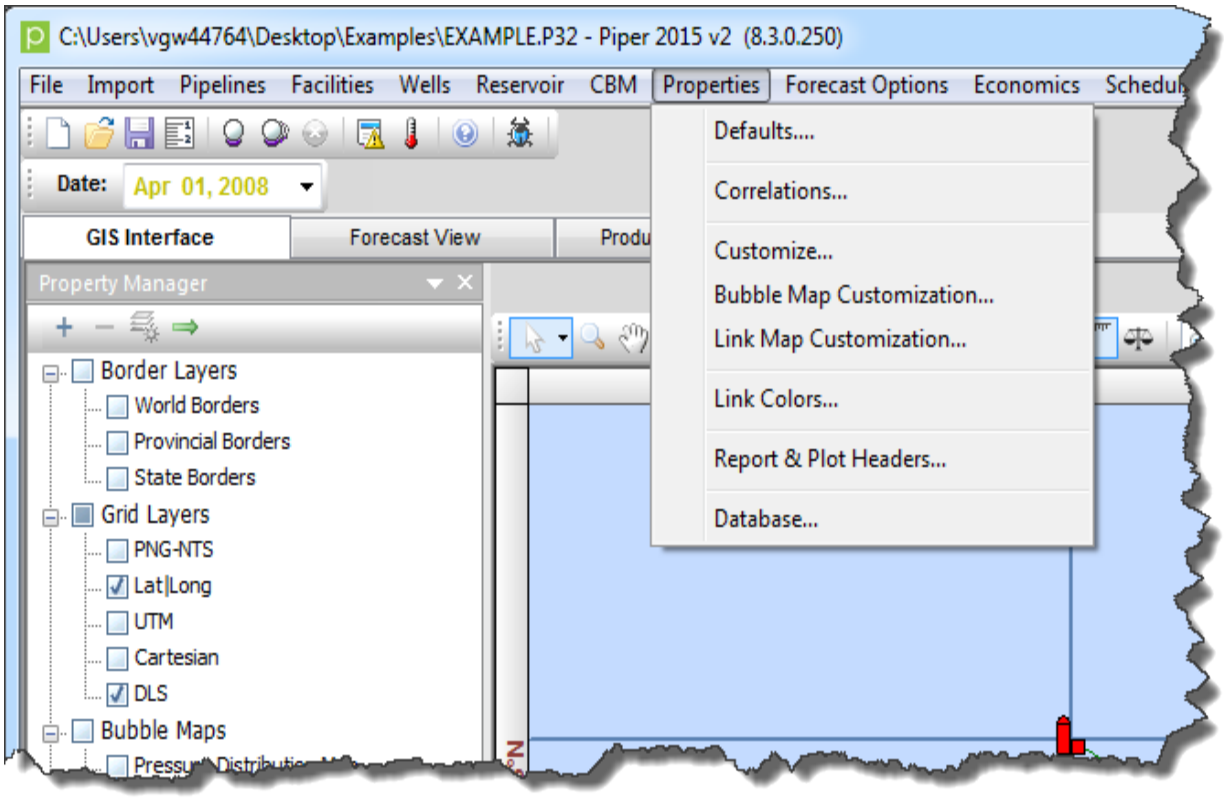


These key menus items warrant additional explanation:

- Properties
- View
- Forecast Options
    - Tracking
- Output
- Help

Properties menu

The properties menu has the following options:



These options are discussed in detail:

- defaults
- correlations

The: Customize, Bubble Map Customization, Link Map Customization, Link Colors, and Report Plot and Headers provide customization tools for various components of your project.

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Defaults

Clicking the **Properties** menu and selecting **Defaults**, opens the Default dialog box.

Erosional Velocity Constant	150	
Max Pipe Seg Division	20	
Max Wellbore Seg Division	20	
EOS Max Pipe Seg Division	20	
EOS Max Wellbore Seg Division	10	
Load Factor	100.0	%
Gasified Liquid Column Gradient	5.994	kPa/m
Node Deliverability Pressure Increment	5	
Default Units For New Files	(•) Metric ( ) Field	
Default Pipe Units	( ) miles/km (•) ft/m	
Default Pump Units for new files	( ) psi/kpa (•) Head(ft)/Head(m)	
Default Loop Link Selection Method	(•) Piper Selects Loop Link ( ) User Selects Loop Link	
Analytical Model Gap Production	(•) Constant Pressure Flow ( ) Well is Shut-in	
Auto Save Defaults	Change Settings	
Simple Composition		
Gas Gravity	0.65	
CO_2		%
H_2S		%
N_2		%
C_{7+} Detail Composition		
CO_2	0.0	%
H_2S	0.0	%
N_2	0.0	%
C_1	92.0	%
C_2	2.0	%
C_3	2.0	%
iC_4	1.0	%
nC_4	1.2	%
iC_5	0.8	%
nC_5	1.0	%
C_6	0.0	%
C_{7+} Detail Composition	0.0	%
Total	100.0	%
C_{7+} MW	150.000000	
C_{7+} γ	0.800000	
Oil Gravity	50.0	°API
Water Gravity	1	
Water Salinity	0	ppm
Critical Velocity Correlation	(•) Turner Water ( ) Turner Condensate	
Default hemisphere for UTM Values	(•) North ( ) South	
Temperature Model Defaults		
Default well site line Temperature	4	°C
Default surrounding temperature (T_∞)	4	°C
Default Heat Transfer Coefficient	0.026	W/(m ^{2}°C)
Units for Standard Conditions	(•) Metric ( ) Field	
Metric Std Conditions		
Temperature	15	°C
Pressure	101	kPa(a)
Field Std Conditions		
Temperature	60	°F
Pressure	14.7	psi(a)

Erosional Velocity Constant - the value of the constant used in the erosional velocity equation. This constant can vary in value from 75 to 150, with 100 considered to be a good value for most cases. Erosional velocity is used to determine pipe sizing and thus flow velocity in order to avoid erosion damage.

Max Pipe Seg Division - used to calculate pressure loss within the model; each pipe is segmented into a default maximum 20 segments. The segmentation process is automatic, with no user intervention required.

Max Wellbore Seg DivisionM - the maximum wellbore segment division affects the level of segmentation of wellbores in pressure loss calculations. The segmentation process is automatic, with no user intervention required.

EOS Max Pipe Seg Division - the EOS maximum pipe segment division affects the level of segmentation of pipelines in pressure loss calculations. The segmentation process is automatic, with no user intervention required.

EOS Max Wellbore Seg Division - the EOS maximum wellbore segment division affects the level of segmentation of wellbores in pressure loss calculations.The segmentation process is automatic, with no user intervention required.

Load Factor - used to adjust reserves at the end of each forecast calculation period. For example, if a load factor of 80% is used, the system is on 80% of the time. The total cumulative production is then multiplied by 0.8 and the produced reserves are adjusted prior to forecasting for the next period.

Gasified Liquid Column Gradient - value used in the wellbore editor to calculate the total pressure drop when liquid columns form. This can vary between 0.2 psi / ft - 0.3 psi / ft, with the default set to 0.265 psi / ft.

Node Deliverability Pressure Increment - the default pressure intervals used when generating the Node Deliverability plot.

Default Units For New Files - metric or field units selection when working with new projects. The default is metric.

Default Pipe Units - magnitude of units to apply to pipe segments. The selections are ft / m, or miles / km. The default is ft / m. The units for the current project determine if field or metric is applied. For new files, the defaults units for new files determine if field or metric is applied.

Default Pump Units for new files - units selection for pumps when working with new projects. The selections are psi / kpa or Head (ft) / Head (m). The default is psi / kpa

Default Loop Link Selection Method - In building a model, Piper is set to automatically detect and assign loop links or allow manual entry of loop links. When Piper Selects Loop Link is used, the 

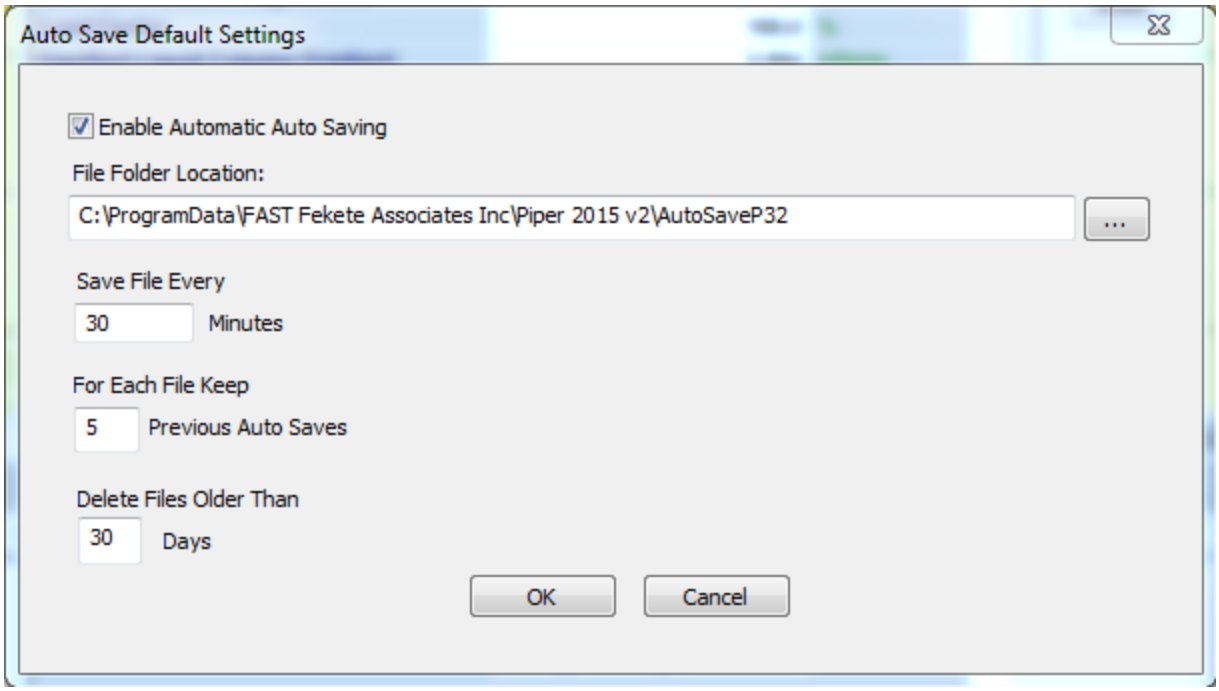
icon on the GIS navigation toolbar is enabled. Using this function recalculates the loop links in the model and reassigns them if necessary.

Analytical Model Gap Production -

Constant Pressure Flow - The well is assumed to operate at a constant flowing pressure equal to that of the last historical production period flowing pressure.

Well is Shut-in - The well is assumed to be shut-in at the end of the last historical production period. A build-up occurs during the gap period until the start period of the Piper forecast.

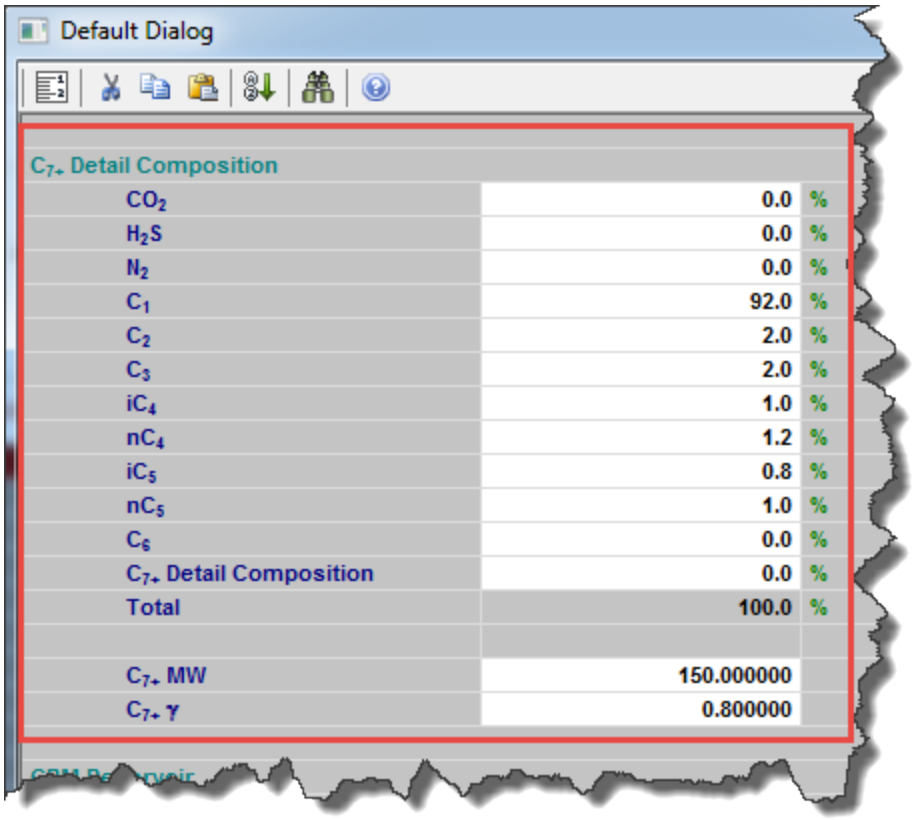
Auto Save Defaults - settings for backing up Piper models while working on them.



- **Enable Automatic Auto Saving** - Enabled as default.
- **File Folder Location** - Path of where the file will be saved.
- **Save File Every** - Time of interval between saves.
- **For Each File Keep** - The maximum number of backup files to be saved. Resets counter once the maximum number is reached.
- **Delete Files Older Than** - Time to wait before automatically remove the file

Simple Composition - Sets the default gas gravity and composition (CO_2, H_2S, N_2) for a simple conventional reservoir**.**

C7+ Detail Composition - Sets the composition for a detailed conventional reservoir consisting of :



Oil Gravity - a measure of the density of petroleum liquid is compared to the density of water (measured at 4°C). If its API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks. The default value is 50 API.

Water Gravity - the reference density of water. The default value is 1.0

Water Salinity - a measure of the salts dissolved in water. The default is 0 ppm.

Critical Velocity Correlation - the critical velocity required to lift liquids given the selected liquid lift correlation. The default can be overridden for individual wells in the wellbore descriptions or wellbore tuning editors. The default critical velocity correlation is Turner Water.

Default hemisphere for UTM Values - Sets the default hemisphere to north or south when using UTM coordinates.

Temperature Model Defaults - used in forecast calculations relating to liquid rich systems (oil or condensates). For more information see adding a temperature model.

- **Default well site line Temperature** - temperature default used for the simple profile type in the seasonal temperatures view. The default values is set to 4°C

- **Default surrounding temperature (T¥)** - used for links in determining the heat transfer coefficient. The default value is set to 4°C.
- **Default Heat Transfer Coefficient** - the rate that heat is transferred from the fluid in the pipe to the surrounding environment (0.026 W / (m^2°C)

Units for Standard Conditions - metric or field for the standard unit values to apply. **The default is metric**

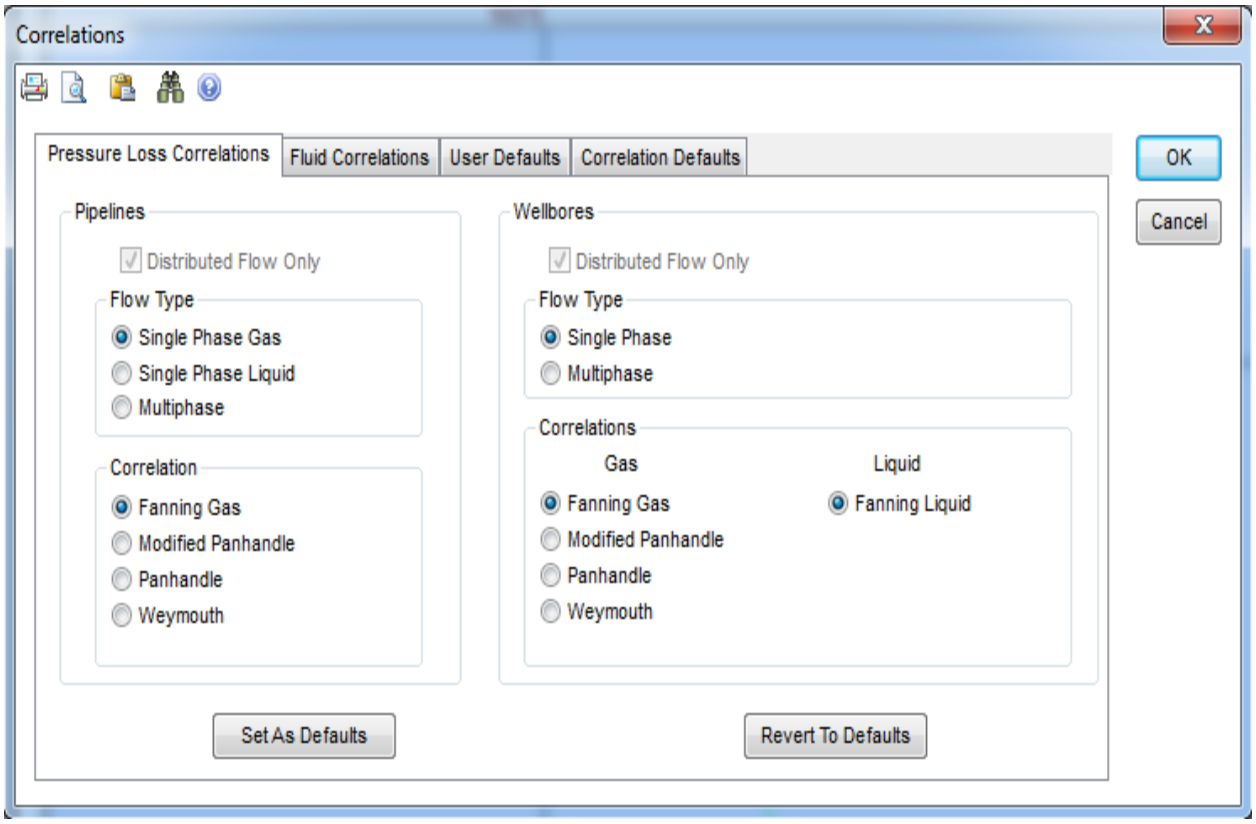
Metric Std Conditions - metric default values for temperature and pressure. The default values are 15 °C, and 101 kPa(a).

Field Std Conditions - field default values for temperature and pressure. The default values are 60°F, and 14.7 psi(a).

Correlations

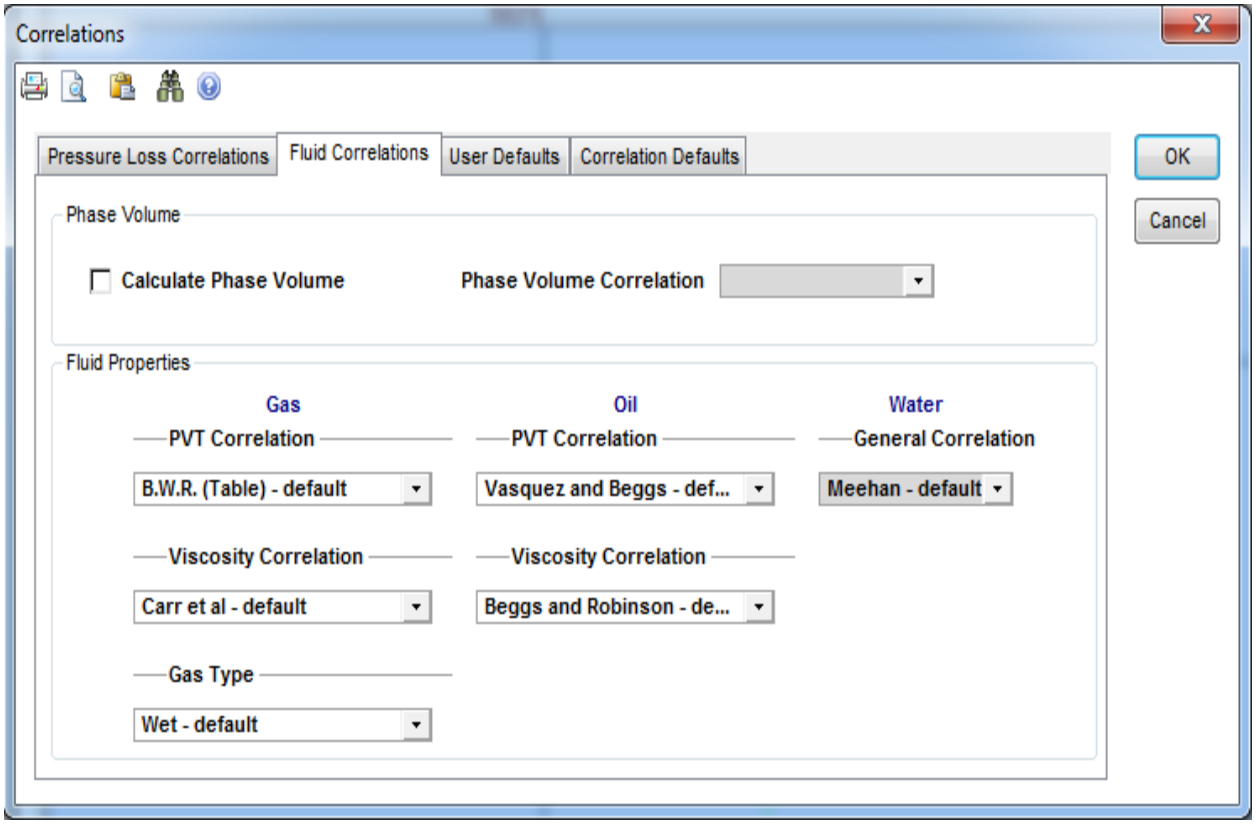
Clicking the **Properties** menu and selecting **Correlations** opens the Correlations dialog box with various tabs.

Pressure loss correlations tab



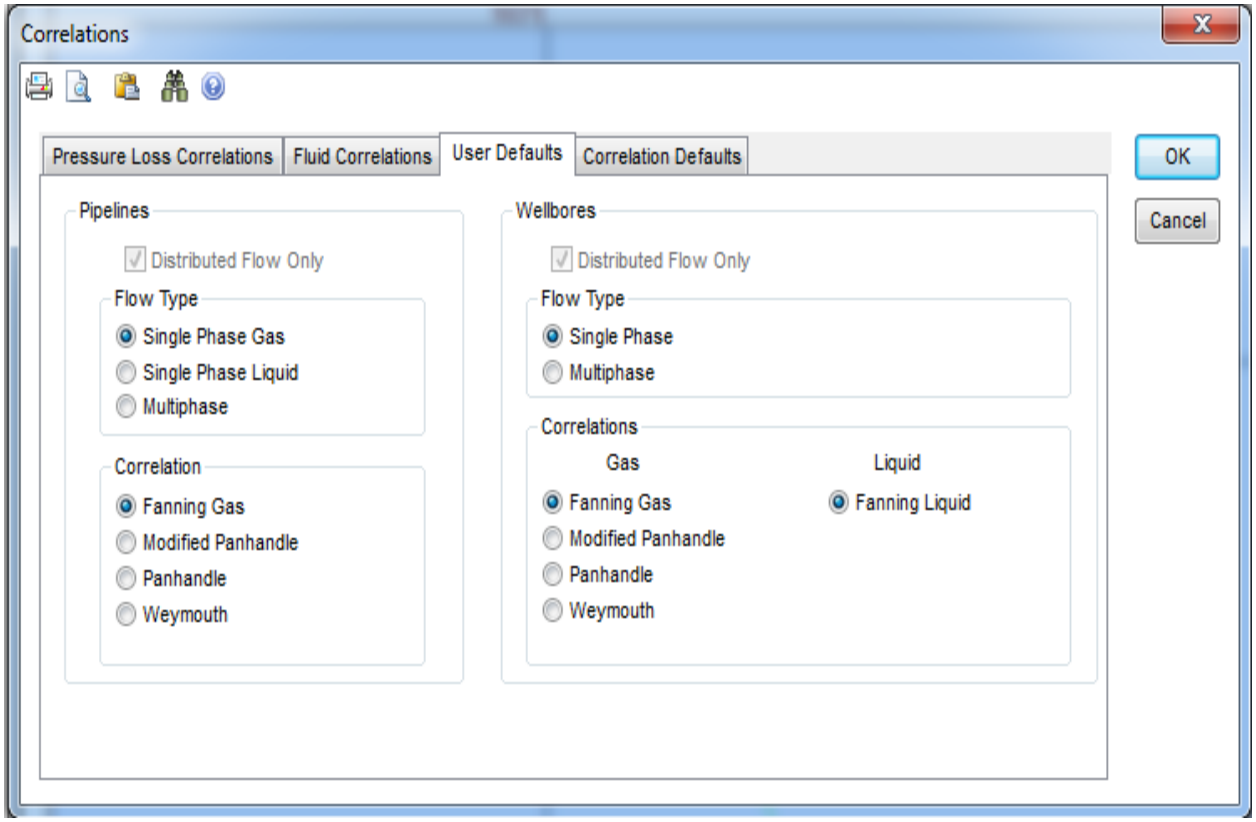
For information on Pressure Loss Correlations selections, see defining pressure loss correlations.

Fluid correlations tab



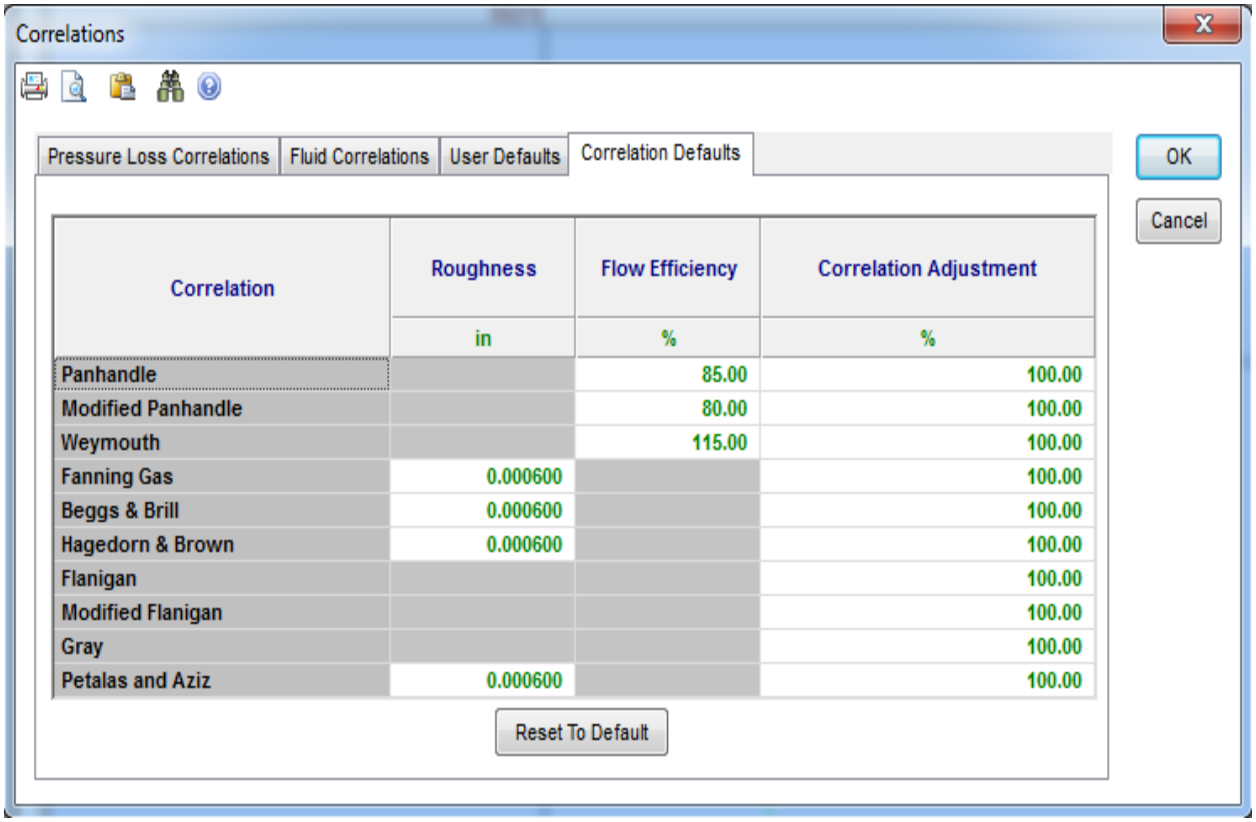
For information on Fluid Correlations selections, see defining fluid correlations.

User defaults tab



User defaults save your correlation selections for use in future files or revert your current correlation selections to a default set.

Correlation defaults tab



Correlation	Roughness	Flow Efficiency	Correlation Adjustment
	in	%	%
Panhandle		85.00	100.00
Modified Panhandle		80.00	100.00
Weymouth		115.00	100.00
Fanning Gas	0.000600		100.00
Beggs & Brill	0.000600		100.00
Hagedorn & Brown	0.000600		100.00
Flanigan			100.00
Modified Flanigan			100.00
Gray			100.00
Petalas and Aziz	0.000600		100.00

Roughness - used in calculating the friction factor for single and multiphase pressure loss correlations. The default rate of 0.000600 in is the average value for a new drawn steel pipe. Roughness must be between 0 and 0.01 inches.

Flow Efficiency - used to manually adjust the amount of pressure loss calculated along a given pipeline segment. Decreasing the flow efficiency increases the pressure loss.

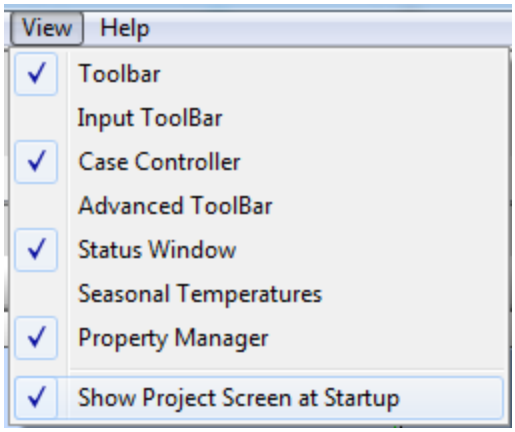
Correlation Adjustment - used to manually adjust the amount of pressure loss calculated along a given pipeline segment.

Note: Values of the above default parameters should not be arbitrarily changed in order to force a match between field measured pressures and calculated pressures. For the vast majority of cases, a discrepancy between measured and calculated pressures is the result of either:

- incorrect gathering system input
- the variation / fluctuation of system pressures over time due to operational changes
- poor data accuracy

View menu

The View menu has the following options:



Selected items are visible by default. For more information on the Status Window and Seasonal Temperatures, click the following links:

- seasonal temperatures
- status window

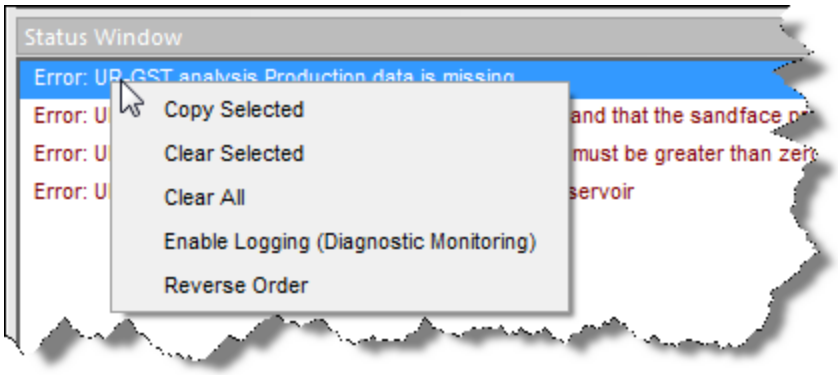
For more information on:

- Toolbar — see main toolbar
- Input Toolbar — see input toolbar
- Case Controller — see case controller
- Advanced Toolbar — see advanced toolbar
- Property Manager — see property manager
- Show Project Screen at Startup — toggles on and off the splash page when launching Piper

Status window

By default, the Status Window is docked at the bottom of the 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.

Note: To hide or show the Status Window, click the **View** menu, **Status Window**.



- **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: \Users\<username>\Documents\IHS Markit\<software version>.
- **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.

Examples of messages displayed in the status window:

- notifications of disabled links
- forecast run outcomes
- warnings, for example:
  - pumps may be operating outside of allowable limits, and as a result, behavior may be unstable
  - compressor capacity curves in a model are not within the range of specified field deliverability, and as a result the model does not solve

Troubleshooting

Reversed flow

When the Status Window displays reversed flow through a compressor and the forecast has aborted, you need to diagnose the issue.

Flow will reverse in situations where there are compressors in parallel, and the flow distribution between those compressors cannot be balanced. The best way to diagnose the issue is to disable the compressor that is reversing and the inlet link into its suction, and run the model again. After the model converges, note the suction pressure and rate that it has converged to. Most likely, that suction pressure will be lower than the minimum suction pressure of the compressor that is reversing. This identifies that the compressor that is reversing needs to be resized to a lower suction pressure, or removed entirely, as it is not contributing to the movement of gas.

Notification messages

The following messages in the Status Window are for notification purposes only and do not require action on your part.

- Compressor choking to meet Qmax
- Loop link X is unconverged

These status messages are provided during the forecast. The last message is displayed after the forecast is complete.

When your forecast is complete, you will see a notification similar to this: Forecast Completed in 0:00:01 sec 6.

Seasonal temperatures

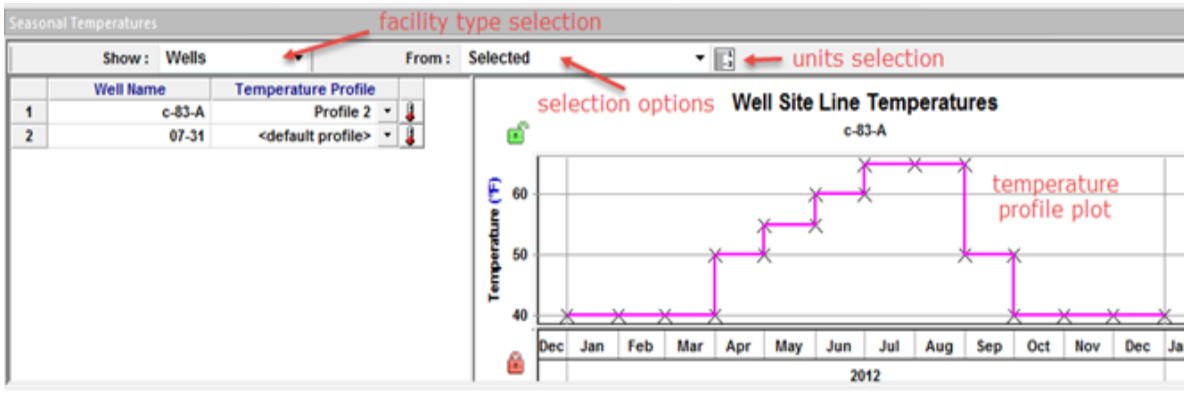
By default, the Seasonal Temperatures pane is not visible. Once it is toggled on, it opens at the bottom of the content pane directly above the status window.

To show or hide the Seasonal Temperatures pane, click the **View** menu and select or deselect **Seasonal Temperatures**.

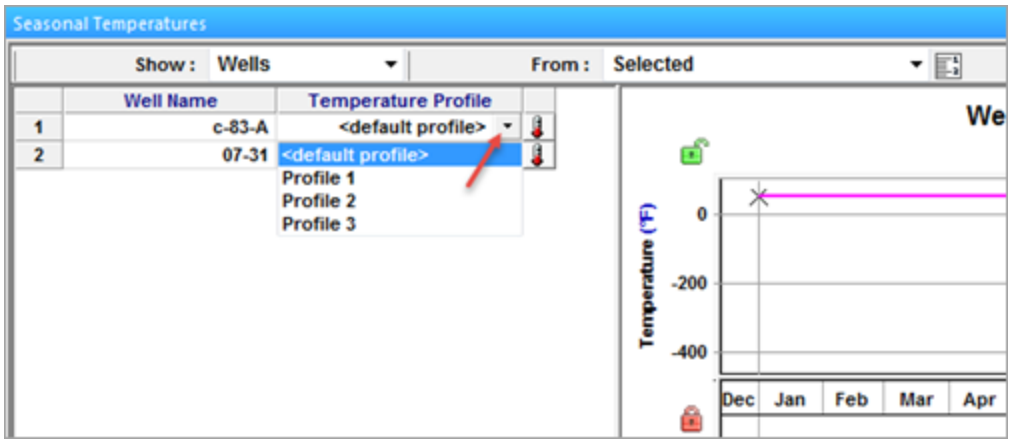
By creating temperature profiles, you can view the effects of temperature on your system. For additional information, see verifying default property settings and adding a temperature profile.

The Seasonal Temperatures pane consists of the following:

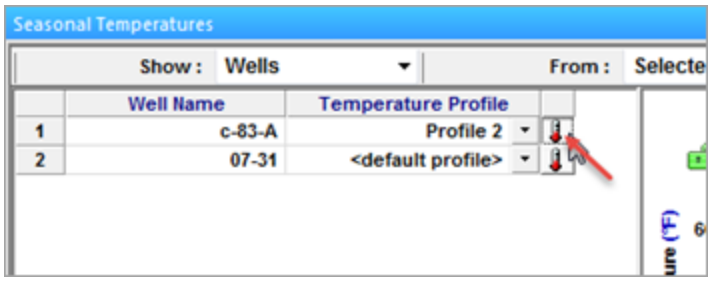
- **Show** — facility type selection; wells or links
- **From** — selection options:
  - Selected — the wells or links listed are only those that are selected on the map
  - All — Current Configuration - the wells and links listed are only those that are present in the current configuration (the configuration currently selected in the case controller)
  - All — All Configurations - the wells and links listed are those present in all configurations
- **Units** selection — field / imperial, or metric
- Temperature profile plot — plot of the data entered for the selected temperature profile



- **Temperature Profile** drop-down list



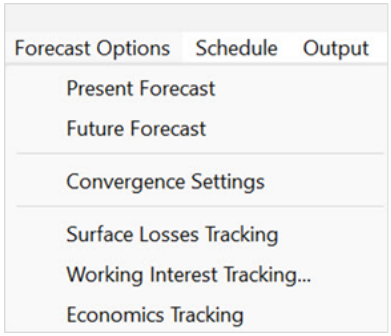
- **Thermometer** icon — when clicked, displays a temperature creation profile dialog box based on the facility type selected in the Show drop-down list



Created profiles are listed in the temperature profile drop-down list.

Forecast options

The Forecast Options menu has the following options:



Running Forecasts

You can run production forecasts for present or future operating conditions. You can also run forecasts from the Forecast View pane, or from the forecast icons on the main toolbar ().

Present Forecast

Performing a present forecast means that the forecast will run until the date selected in the case controller.

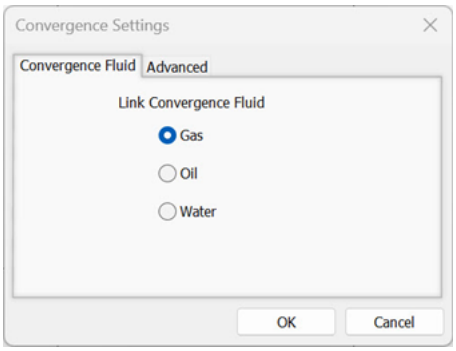
Future forecast

Performing a future forecast means that the forecast will run for the entire forecast duration. You can pause and resume a future forecast by pressing F3.

Convergence Settings

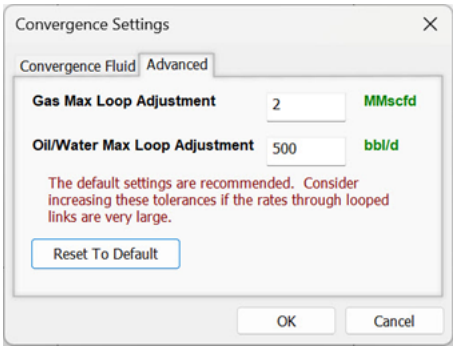
You can select which fluid is used in loop-link convergence, and you can also set the maximum adjustment rate.

Convergence Fluid



Select the fluid used in loop link convergence. For example, if you have a water-only system (no gas or oil), then you should select **Water**. After changing the convergence fluid, rerun the forecast for the change to take effect.

Advanced



Use Advanced to change loop adjustment values if the forecast does not converge (for example, when rates through looped links are very large).

Gas Max Loop Adjustment: Sets the gas volume adjustment applied per iteration.

Oil/Water Max Loop Adjustment: Sets the oil/water volume adjustment applied per iteration.

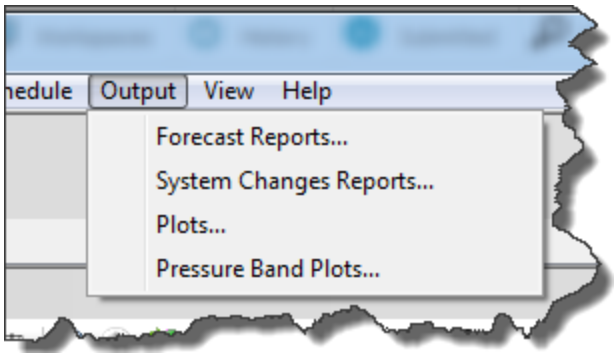
Larger values apply a coarser adjustment to each iteration and may help in higher-volume looped systems.

Tracking

Please refer to Tracking for Surface Losses, Working Interest, or Economics tracking.

Output menu

After a forecast has been generated, you can view and export key production data.



For additional information on Forecast Reports, see forecast reports.

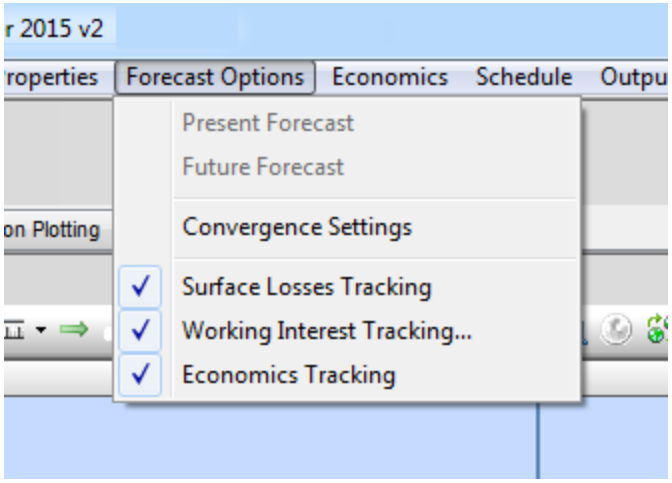
For additional information on System Changes Reports, see system changes reports.

For additional information on Plots, see plots.

For additional information on Pressure Band Plots, see pressure band plots.

Tracking

Your tracking options are listed in the Forecast Options menu.



Surface loss tracking

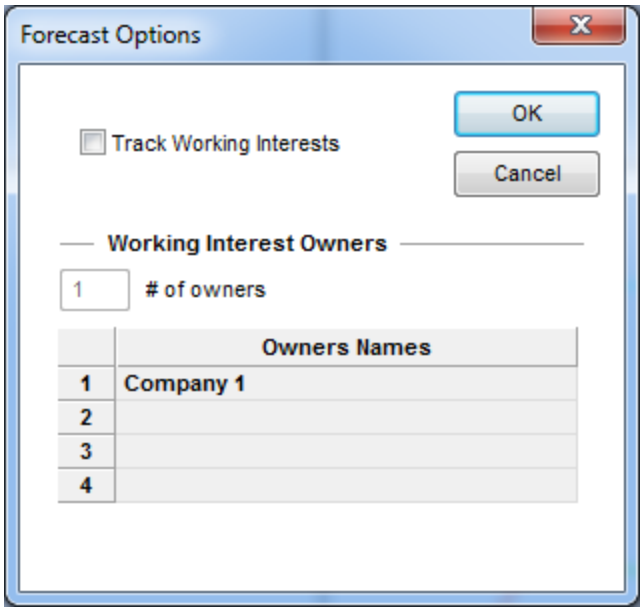
You can specify a gas content loss between the reservoir and surface, which is specified as a percentage of the gas produced.

When this option is selected, you can enter surface loss in the Reservoirs editor, Surface Loss column. This column is not displayed if surface loss tracking is not selected. Surface loss, related to the reservoir, refers to the percentage of production that is lost. For example, this may be a result of venting, leaks, or fuel gas.

Working interest tracking

When working interest tracking is selected, the Forecast Options dialog box opens. Working interest tracking is enabled when you select the Track Working Interests checkbox in the dialog box. As you increase the # of owners, additional rows are added to the Owners Names column. The default company names can be overwritten to reflect actual working interest groups.

By selecting this option, you can enter working interests for each well in the Well Options editor, and working interest volumes can be displayed in the output reports.



Economics tracking

Clicking this option displays the Economics menu in the menus toolbar. For more information see adding economics.

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Help menu

The Help menu has the following options:

- Help — opens Piper's WebHelp.
- File Information — opens the File Information dialog box where you can view the modification history for various versions of Piper.
- Toolbar Icons — opens the Toolbars topic in the help.
- Keyboard and Mouse Commands — opens the Navigation topic in the help.
- Nomenclature — opens the Glossary topic in the help.
- GIS Help — opens the GIS interface topic in the help.
- Licensing — opens the Licensing dialog box where you can configure and activate / deactivate your licenses.

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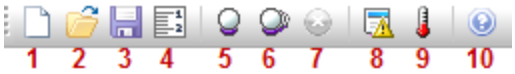
Toolbars

Piper toolbars include the following:

- main
- input
- advanced

Note: The GIS interface also has toolbars: navigation, design, and pipeline.

Main toolbar



The icons on the main toolbar are as follows:

1. **New** — opens a blank document
2. **Open** — allows a previously created file to be opened
3. **Save** — saves all changes to the current file
4. **Change Units** — toggles units between metric (m / kg / °C) and imperial (ft / lb / °F) unit systems
5. **Present Forecast** — calculates the values of the gathering map based on the date specified. The forecast runs until the day of the currently set configuration date has been reached. Note that a present-day forecast is only run for the purpose of tuning the model (i.e., matching the model's calculated values to the ones measured in the field).
6. **Future Forecast** — calculates the values of the gathering map based on the date specified. The forecast runs until the end of the duration specified in the forecast view.

   Note: When a forecast is run, its details are displayed in the status window.
7. **Stop Forecast** — halts current forecast calculations. The icon is enabled when a forecast is running. It is gray-out when there is no forecast running.
8. **Status** — toggles the display of the status window
9. **Show / Hide Temperature Model Editor** — used to enter a model's boundary temperatures for calculating ambient heat loss, and corresponding changes to fluid temperature
10. **Display help for current task or command** — opens the online help

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Input toolbar

By default, this toolbar is hidden until you select **Input ToolBar**from the **View** menu.



1. **GIS Position Editor** — opens the GIS Positions dialog box
2. **Edit Delivery Point Data** — opens the Delivery Point dialog box
3. **Edit Gathering System Data** — opens the Gathering System dialog box
4. **Edit Well Data** — opens the Well Editor dialog box, Well Deliverability
5. **Edit Well Options Data** — opens the Well Editor dialog box, Options
6. **Edit Reservoir Data** — opens the Reservoirs dialog box
7. **Edit Compressor Data** — opens the Compressors dialog box
8. **Edit Pump Data** — opens the Pumps dialog box
9. **Edit Contract Data** — opens the Contracts dialog box
10. **Edit Separator Data** — opens the Separator dialog box
11. **Edit Refrigeration Data** — opens the Refrigeration Plants dialog box
12. **Edit Amine Data** — opens the Amines dialog box
13. **Edit Intake / Offtake Data** — opens the Intakes / Offtakes dialog box
14. **Edit Pressure Loss Data** — opens the Pressure Loss dialog box

Advanced toolbar

By default, this toolbar is hidden until you select **Advanced ToolBar**from the **View** menu.



1. **Edit Wellbore Description Data** — opens the Well Editor dialog box, Wellbore Descriptions
2. **Edit Wellbore Tuning Data** — opens the Well Editor dialog box, Wellbore Tuning
3. **Edit Relative Permeability Curve Data** — opens the Relative Permeability Curves dialog box

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Case controller

By default, the case controller is located directly below the main toolbar and is visible when the application is launched. It can be toggled on and off from the View menu in the main toolbar.



The case controller displays the default date that is applied if any changes are made to the model either through an editor, or on the map. For further information on making configuration changes, see adding changes after building your model. After a change is made, the date is highlighted in yellow in the case controller and forecast view, and is referred to as a configuration date. You can select various dates from the drop-down arrow and view model conditions as of the selected date.

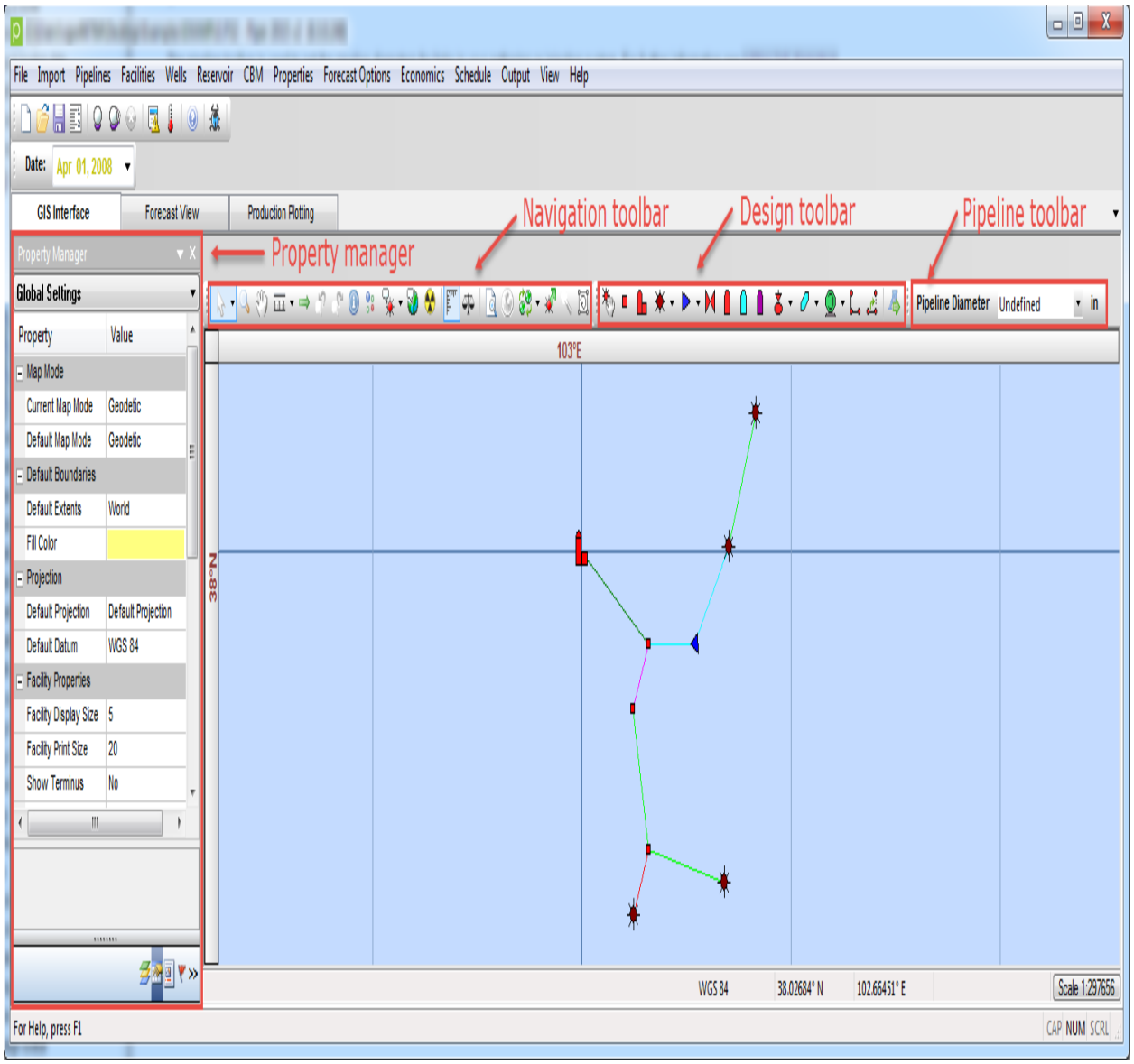
It is important to manage dates within the model. Make sure you have selected the appropriate date before making any changes in order to avoid confusion later.

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GIS interface

The four main components of the GIS interface are the:

- property manager
- navigation toolbar
- design toolbar
- pipeline toolbar



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Property Manager

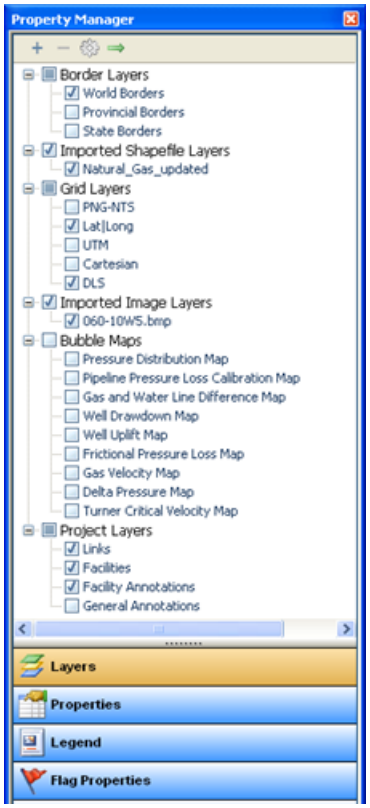
The Property Manager manages the following components of the GIS:

- Layers
- Properties
- Legend
- Flag properties

Layers

The Property Manager pane, Layers, manages the following layer types:

- **Border Layers** – toggles on and off the display of world, provincial, and state borders
- **Imported Shapefile Layers** – toggles on and off imported shapefiles
- **Grid Layers** – toggles on and off the display of coordinate system grid layers
- **Imported Image Layers** – toggles on and off imported image files
- **Bubble Maps** – toggles on and off the display of bubble map and link map layers
- **Project Layers** – toggles on and off the display of links, facilities, and annotations
- **Flag Layers** - toggle on and off the display of flags



Layer functionality

By default, layers are grouped by type in the order displayed above. The display order of the layers determines the drawing order for what is visible on the map. Each layer draws over the previous layer, potentially obscuring the previous layer's information on the map. For example, if you choose

to place your Project Layers first, links, facilities, and annotations may no longer be visible if the border layers are toggled on.

You can group layers by type, or by a flat list. Each layer can be moved to a new position within its group type or within a flat list in the layer tree. Each group can also be moved to a new group location in the tree; it cannot be moved to within another layer group. The layer order remains in place when you restart the application.

Layers can be added or removed with the exception of layers in the border, grid, and project layer groups. These are default layers and are always included.

Border layers

Border layers display the world map including provincial borders and states for North America. These are default layers that cannot be deleted.

Imported shapefile layers

The following shapefile layer options are available:

- **Shapefile Info** - view details about the shapefile, such as, the number and type of shape, label selection, and the bounding box
- **DBF Info** - database files (DBF) that contain attribute information that can be imported when the shapefile is converted to facilities or links
- **Goto Shapefile Area** - zooms the map to the area where the shapefile is loaded
- **Customize Drawing Tools** - change the line color, line thickness, fill color, and other visual attributes of the shape. This option is also available for the default border shapefiles
- **Highlight Shape(s)** - highlight the selected shape
- **Show Labels** - show the label title for the shape

Only shapefiles with Mercator projections, and locations in geographical coordinates (i.e., latitude and longitude), can be imported.

The following DBF data is available for import when a shapefile is converted to facilities or links.

Facility attribute DBF data

If the shapefile is converted to facilities, the following data can be imported:

DBF Item	Piper Editor Location	Comments
Name	Facility Editor	Includes a numbering system for unique naming

DBF Item	Piper Editor Location	Comments
Surface Location	GIS Position Editor	Can be lat / long, UTM, DLS, NTS, and / or an elevation
Sandface location	GIS Position Editor	Can be lat / long, UTM, DLS, NTS, and / or an elevation
Remarks	Facility Editor	

Link attribute DBF data

If the shapefile is converted to links,. the following data can be imported:

DBF Item	Piper Editor Location	Comments
Name	Gathering System Editor	Includes a numbering system for unique naming
Pipe Length	Gathering System Editor	Scaled for individual links based on proportional map distance
Internal Diameter	Gathering System Editor	
External Diameter	Gathering System Editor	Used with wall thickness to calculate inner diameter
Wall Thickness	Gathering System Editor	Used with external diameter to calculate inner diameter
Roughness	Gathering System Editor	
Remarks	Gathering System Editor	

For technical information on shapefiles, see ESRI Shapefile Technical Description (a new window opens).

Compatibility

If you encounter issues importing a shapefile, it may be because your shapefile is incompatible with Piper. Ensure that your shapefile meets the following requirements:

- Mercator projection
- Geographic coordinate system (GCS)
- NAD 27 (North American Datum, created in 1927), or NAD 83 (North American Datum, modified in 1983), or WGS 84 (World Geodetic System, modified in 1984)
- Latitude and Longitude in decimal degrees

Grid layers

These layers identify locations on the earth's surface through the following grid selections: PNG-NTS, Lat/Long, UTM, and DLS. Relative locations are provided using the Cartesian grid.

Imported image layers

Imported images, used to provide additional visual references, such as contour lines for elevation, are included in this group.

Bubble map layers

Bubble map layers are diagnostic tools that display the operational conditions of the model.

By default, the following bubble maps are available:

- **Pressure distribution** - displays operating pressures throughout the model
- **Pipeline pressure loss calibration** - the difference between measured pipeline pressures (measured gas line pressure values in the well options) and calculated pressures at each of the wells
- **Gas and water line difference** - displays the difference between the calculated line pressure loss and the measured water line pressure (entered in the Well Options menu)
- **Well drawdown** - displays the wellhead drawdown for wells that have been defined using a deliverability model (wellhead, sandface, or reservoir model)
- **Well uplift** - displays the ultimate uplift potential for wells that have been defined using a deliverability model (wellhead, sandface, or reservoir model)

By default, the following link maps are available:

- **Frictional pressure loss** - identifies pipelines with limited capacity
- **Gas velocity**- displays the average gas velocity in each segment of the pipeline
- **Delta pressure** - displays the total line pressure loss in each segment of the pipeline
- **Turner critical velocity** - displays whether the current velocity in the pipeline segment is above or below the Turner critical velocity

Additional options provided for bubble maps include:

- **Options** - to redefine bubble map preferences and the entities the bubble map is applied to
- **Auto Range** - to calculate a range based on the data for the entities used in the bubble map
- **Legend** - to redefine the size, position, transparency, and visibility of the legend

Project layers

This layer includes links, facilities, facility annotations, and general annotations. The facilities layer provides an additional menu option (Displaying All) to toggle viewing on and off for facility types.

Flag layers

With flags, you can highlight specific facilities and wells to mark areas of interest on the map. Once a flag is created, it is added to the Property Manager as a flag layer.

After an initial flag layer is created, the flag layer options are expanded to include:

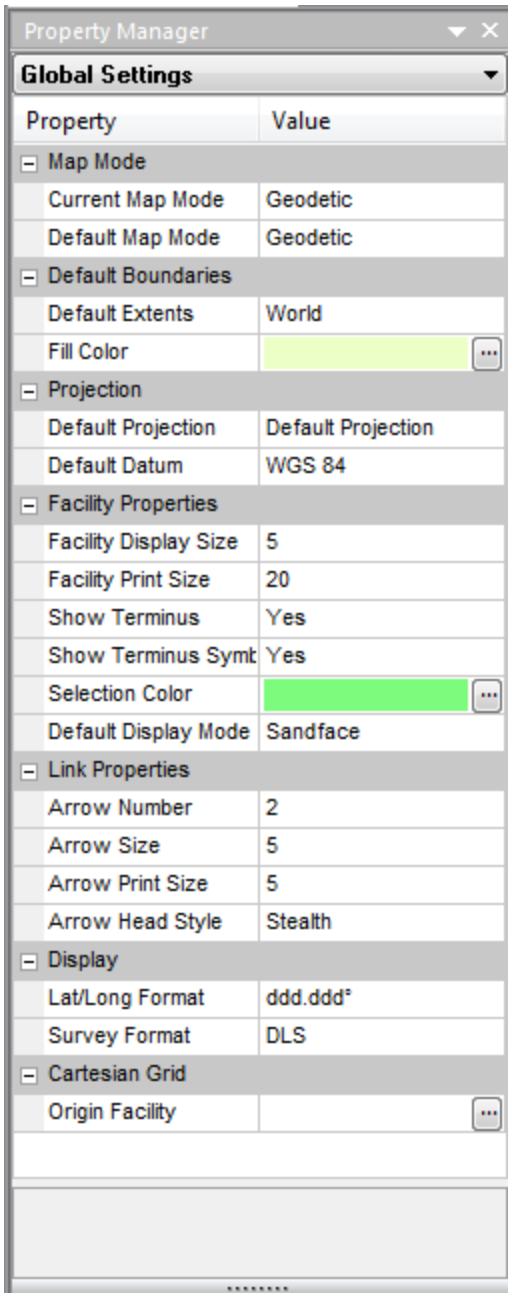
- **Add Flag Layer** - adds a flag to Flag Layers, Flag Properties, and to selected facilities on the GIS map
- **Flag Properties** - changes the flag properties associated with a flag layer
- **Remove Flag Layer** - removes the flag from the Flag Layers, Flag Properties, and the GIS map

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Properties

The Property Manager pane, Properties, displays the following:

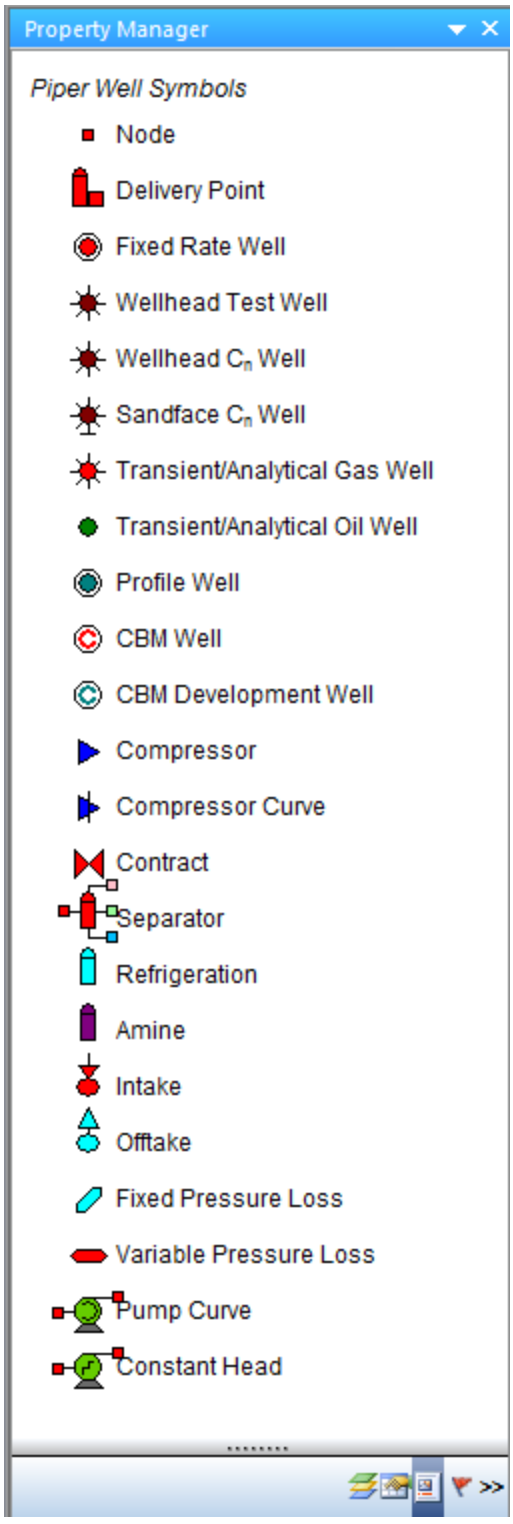
- **Current Map Mode** – the currently selected map mode: Cartesian or GIS
- **Default Map Mode** – the default map mode selection, Cartesian or GIS, applied to new models
- **Default Extents** – the default borders used when a new file is created, or when Piper is first loaded.
- **Fill Color** - the color used to display the world border layer
- **Default projection** - the default projection (Mercator) used to map the earth's surface
- **Default Datum** – the default datum selection applied to new models
- **Facility Display Size** – the size of the facility. You can also adjust this setting by clicking the **Properties** menu, and selecting **Customize**.
- **Facility Print Size** – the size of the facility that is printed. You can also adjust this setting by clicking the **Properties** menu, and selecting **Customize**.
- **Show Terminus** – shows the well location at the sandface and wellhead
- **Show Terminus Symbol** – designates the terminus location with SF for sandface, or WH for wellhead
- **Selection color** - the color used to display selected facilities
- **Default Display Mode** – toggles the terminus display between wellhead or sandface
- **Arrow Number** - based on the link length, the maximum number of arrow heads to display per link
- **Arrow Size** – the size of the flow arrows that are printed
- **Arrow Print Size** - the size of the arrow that is printed
- **Arrow Head Style** - the style of the arrow head (Stealth, Filled, or Open)
- **Lat/Long Format** – the lat / long display format
- **Survey Format** - the default survey display format
- **Origin Facility** – the facility selected as the (0, 0) origin for the Cartesian grid


Property Manager
Global Settings
Property
Value
Map Mode
Current Map Mode
Geodetic
Default Map Mode
Geodetic
Default Boundaries
Default Extents
World
Fill Color
Projection
Default Projection
Default Projection
Default Datum
WGS 84
Facility Properties
Facility Display Size
5
Facility Print Size
20
Show Terminus
Yes
Show Terminus Symb
Yes
Selection Color
Default Display Mode
Sandface
Link Properties
Arrow Number
2
Arrow Size
5
Arrow Print Size
5
Arrow Head Style
Stealth
Display
Lat/Long Format
ddd.ddd°
Survey Format
DLS
Cartesian Grid
Origin Facility

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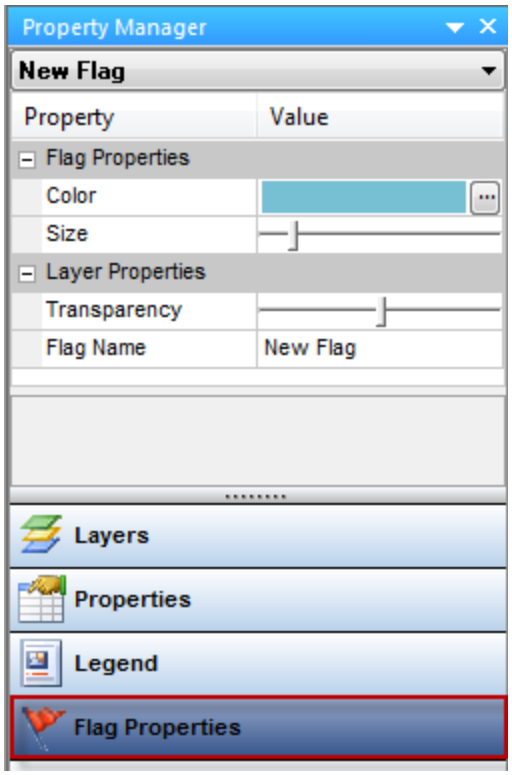
Legend

The Property Manager pane, Legend, displays all the symbols used on the GIS map. For detailed information on each facility type, see surface facilities.


Property Manager
Piper Well Symbols
Node
Delivery Point
Fixed Rate Well
Wellhead Test Well
Wellhead Cn Well
Sandface Cn Well
Transient/Analytical Gas Well
Transient/Analytical Oil Well
Profile Well
CBM Well
CBM Development Well
Compressor
Compressor Curve
Contract
Separator
Refrigeration
Amine
Intake
Offtake
Fixed Pressure Loss
Variable Pressure Loss
Pump Curve
Constant Head
>>

Flag Properties

The Property Manager pane, Flag Properties, provides functionality for editing flag color, size, transparency, and name.



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Navigation toolbar

The navigation toolbar is located directly above the GIS map.



These are the navigation toolbar icons:

Pointer - select facilities, nodes, and links. You can right-click this icon to select drop-down options for facilities, links, and nodes.

Zoom - increase or decrease the display size. Hold-and-click to zoom in to a box area, or right-click to zoom out.

Pan - changes the map position

Measure Tool - measure distances on the map

Goto - navigate to a specific location

Undo Zoom - resets the display to the previously set zoom

Redo Zoom - reapplies the zoom setting

Identify - displays location information in the Property Manager

Bubble Map - opens the bubble map editor

Annotation Display Options - opens the facility annotation editor. Use the drop-down arrow to change annotations for various facilities.

General Annotations - opens the general annotation editor

Reset - resets the map to the default zoom setting

 **Show Rulers** - shows and hides line identifiers for the boundaries of the map (for example, latitude and longitude lines)

 **Map Scale** - shows and hides the map scale

 **Print Preview** - switches to print preview mode

 **Map Mode** - switches the Cartesian mode to GIS mode using the same process as legacy importing. Note that this option does not switch back to Cartesian mode from the GIS mode.

 **Datum Mode** - changes the default datum of the map to the selected datum

 **Shapefile Export** - exports the current system as a shapefile. Links are exported as polyline shape types, and facilities are exported as point shape types.

 **Apply Changes** - applies changes to other configurations in the model

 **Recalculate Loop Link Locations** - detects and assigns loops in the gathering system. Note that this icon is only enabled when an auto-loop detection is enabled; otherwise the icon is grayed-out.

Design toolbar

The navigation toolbar is located to the right of the navigation toolbar.



 **Move a Facility** - moves the position of a selected facility. If you select multiple facilities and links, all of the highlighted items move together.

 **Node** - creates a node on the map where it is placed

 **Delivery Point** - creates a delivery point on the map where it is placed. Note that only one delivery point may be added to a model.

 **Well** - creates a well on the map where it is placed. You can select various types of wells by clicking the drop-down arrow

 **Compressor** - creates a compressor on the map where it is placed. You can select a compressor (single suction) or a compressor curve from the drop-down arrow

 **Contract** - creates a contract on the map where it is placed

 **Separator** - creates a separator facility on the map where it is placed

 **Refrigeration** - creates a refrigerator facility on the map where it is placed

 **Amine** - creates an amine facility on the map where it is placed

 **Intake / Offtake** - creates an intake or offtake on the map where it is placed. You can select either intakes or offtakes from the drop-down arrow

 **Fixed Pressure Loss** - creates a pressure loss on the map where it is placed. You can select either a fixed pressure loss or a variable pressure loss from the drop-down arrow

 **Pump Curve** - creates a pump on the map where it is placed. You can select either a pump curve or constant head pump from the drop-down arrow

 **Links** - draws links between facilities on the map

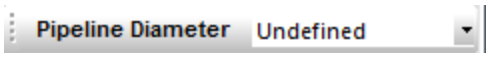
 **Reconnect Links** - changes link connection points. To reconnect to another facility, click at either end of a link

 **Name Generator** - customizes the naming conventions for facilities and nodes that are placed on the map

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Energy

Pipeline toolbar

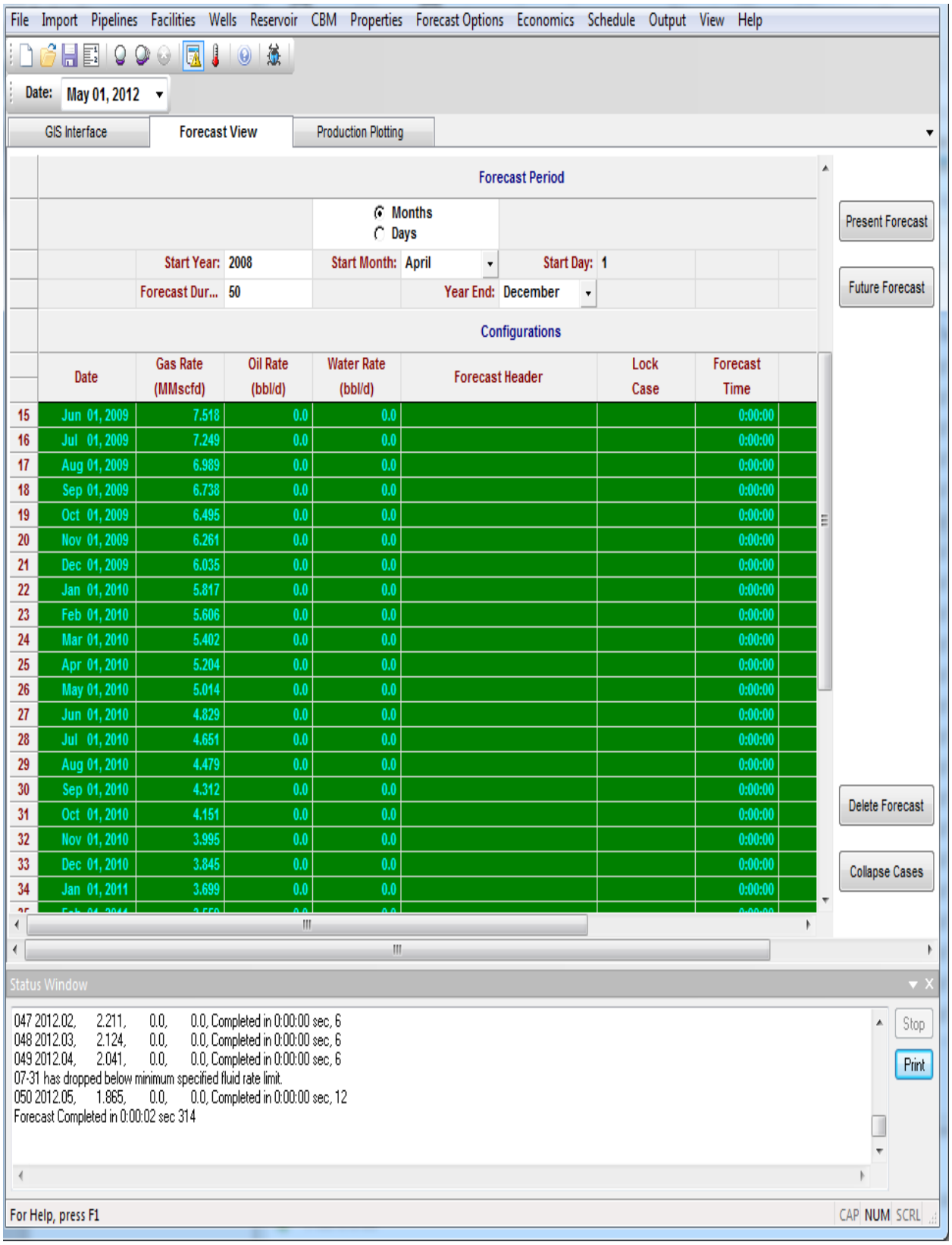
The pipeline toolbar is used to set the pipeline diameters for links in your gathering or injection system. For further information, see editing link diameters.



S&P Global
Energy

Forecast view

You can use the forecast view to enter your forecast parameters, run present or future forecasts, manage your configurations, and make configuration changes.


File Import Pipelines Facilities Wells Reservoir CBM Properties Forecast Options Economics Schedule Output View Help
Date: May 01, 2012
GIS Interface
Forecast View
Production Plotting
Forecast Period
Months
Days
Start Year: 2008
Start Month: April
Start Day: 1
Forecast Dur... 50
Year End: December
Present Forecast
Future Forecast
Configurations
Date
Gas Rate (MMscfd)
Oil Rate (bbl/d)
Water Rate (bbl/d)
Forecast Header
Lock Case
Forecast Time
15 Jun 01, 2009 7.518 0.0 0.0 0:00:00
16 Jul 01, 2009 7.249 0.0 0.0 0:00:00
17 Aug 01, 2009 6.989 0.0 0.0 0:00:00
18 Sep 01, 2009 6.738 0.0 0.0 0:00:00
19 Oct 01, 2009 6.495 0.0 0.0 0:00:00
20 Nov 01, 2009 6.261 0.0 0.0 0:00:00
21 Dec 01, 2009 6.035 0.0 0.0 0:00:00
22 Jan 01, 2010 5.817 0.0 0.0 0:00:00
23 Feb 01, 2010 5.606 0.0 0.0 0:00:00
24 Mar 01, 2010 5.402 0.0 0.0 0:00:00
25 Apr 01, 2010 5.204 0.0 0.0 0:00:00
26 May 01, 2010 5.014 0.0 0.0 0:00:00
27 Jun 01, 2010 4.829 0.0 0.0 0:00:00
28 Jul 01, 2010 4.651 0.0 0.0 0:00:00
29 Aug 01, 2010 4.479 0.0 0.0 0:00:00
30 Sep 01, 2010 4.312 0.0 0.0 0:00:00
31 Oct 01, 2010 4.151 0.0 0.0 0:00:00
32 Nov 01, 2010 3.995 0.0 0.0 0:00:00
33 Dec 01, 2010 3.845 0.0 0.0 0:00:00
34 Jan 01, 2011 3.699 0.0 0.0 0:00:00
Delete Forecast
Collapse Cases
Status Window
047 2012.02, 2.211, 0.0, 0.0, Completed in 0:00:00 sec, 6
048 2012.03, 2.124, 0.0, 0.0, Completed in 0:00:00 sec, 6
049 2012.04, 2.041, 0.0, 0.0, Completed in 0:00:00 sec, 6
07-31 has dropped below minimum specified fluid rate limit.
050 2012.05, 1.865, 0.0, 0.0, Completed in 0:00:00 sec, 12
Forecast Completed in 0:00:02 sec 314
Stop
Print
For Help, press F1
CAP NUM SCRL

Forecast parameters

Applicable forecast parameters are:

Forecast Period - options are Months or Days.

Important: If a forecast is converted from months to days (or from days to months) then any existing forecast is deleted. There can only be one configuration when switching from a daily forecast to a monthly forecast, therefore any changes in the daily forecast must be moved to the first monthly configuration date.

Start Year - the first year of your forecast run. The default is the current year.

Start Month - the first month of a future forecast. Production is assumed to start on the first (1st) day of the specified month. The default is the current month.

Start Day - the first day of a daily future forecast. This applies only if the forecast period is selected as days.

Forecast Duration - the length of the forecast period, in months or days, depending on the forecast period selection.

Year End - (this feature only applies to monthly forecasts) the last month used for accounting purposes. In the status window, a gap is placed after this month as a visual indicator. You can choose December for calendar year forecasts, October for typical gas contract year forecasts, or any other month for a forecast that corresponds to a financial year-end. The default is December (for December 31st).

Running forecasts

From the Forecast View, you can run production forecasts for present or future operating conditions. You can also run forecasts from the Forecast Options menu and from the forecast icons on the main toolbar ().

Present forecast

Performing a present forecast means that the forecast will run until the date selected in the case controller.

Future forecast

Performing a future forecast means that the forecast will run for the entire forecast duration. You can pause and resume a future forecast by pressing F3.

Forecast configuration changes

You can make changes to your model at different dates throughout the forecast period. Select a date from the Date column in the forecast view grid and proceed with the required change in the corresponding editor. The editor opens with the selected date highlighted in the forecast date tree. You are prompted to apply the changes once you exit the editor. For more information on making configuration changes, see adding changes after building your model.

Manage your forecasts

The following functionality is available to manage your forecasts:

- **Managing multiple configuration dates** - in the Forecast View tab, you can filter the forecast periods that are displayed. Click Collapse Cases to show only rows with configuration changes (these dates are displayed in yellow). Click Expand Cases to show all dates.
- **Delete configuration(s)** - select the configuration date to be deleted, then right-click and select Delete Case. Alternatively, right-click in the forecast grid view and select Delete Cases. From the dialog box that displays, select the cases you want to delete.

  Important: You are not prompted to confirm a deletion.
- **Delete entire forecast** - click Delete Forecast to remove the entire forecast.
- **Partially delete forecast** - select a configuration date, then right-click in the forecast grid view and select Delete Forecast. This will delete the forecast for the selected date and any future dates in the grid.
- **Copy a configuration date** - make sure all dates are listed in the forecast view (click Expand Cases if you collapsed cases previously), select a case to copy, and then select a date to paste it to.
- **Lock case** - select this checkbox for configuration dates you want to lock. This prevents edits from occurring on all facilities that exist for that configuration date until the next configuration date.

  In Piper 2015v2, the Include Config column was removed from the grid. Therefore, it is no longer possible to include or exclude configurations from a forecast run. Configurations can only be managed as described above. For files upgraded from a previous version of Piper, all configurations are now included, even if they were excluded before.

S&P Global
Energy

Production plotting

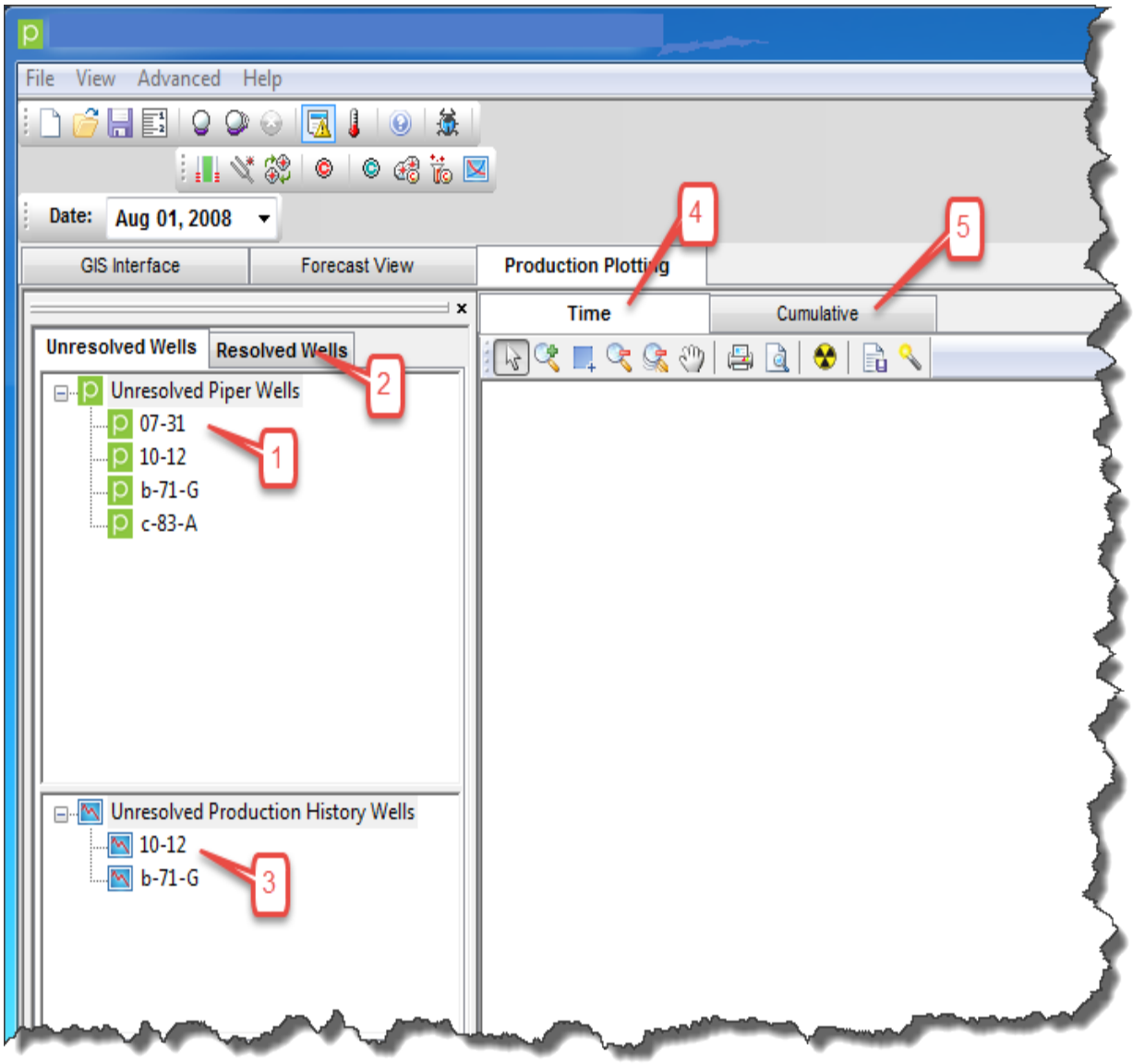
The production plotting tab provides a visual comparison of historical data (imported from analytical models, or historical production data) and your forecast data. The data is plotted in the Time and Cumulative tabs of the production plotting view and is used to validate the results generated by your forecast.

Production plots have the same functionality as other plots. For more information, see using plots.

The Production Plotting tab consists of:

1. **Unresolved Wells** tab - existing wells in the model that have not been resolved with wells from imported historical production data, or with wells imported from an analytical model.
2. **Resolved Wells** tab - a list of wells imported from historical production data that have been resolved manually or by matching. Also listed in this tab are wells that are automatically resolved from imported analytical models.
3. **Unresolved Production History Wells** pane - a list of wells that were imported with historical production data
4. **Time** plot - a Rate vs. Time plot of the production data (both historic and forecast production data if wells have been resolved)
5. **Cumulative** plot - a Cumulative Rate vs. Time plot of the production data (both historic and forecast production data, if wells have been resolved)

   Note that the plots can display pressure and rate data. Right-click in the Legend and select Show on Plot to select your plot data.



Toolbar

The Production Plotting tab has a toolbar with many common icons, and some unique items, which are described below:

- **Reset Plot Attributes** — resets your plot attributes to default settings.
- **Save Plot Settings** — saves dataset and axes settings for use in Production Plotting tab.

-  **Apply plot settings to other wells** — select from these options:
  - **Apply All Settings** —applies Dataset and Axes settings to the other wells.
  - **Apply Axis Settings** — applies the axis settings (units, location) to all wells.
  - **Apply DataSet Settings** — applies the active dataset and dataset customization settings to all wells.

Editors

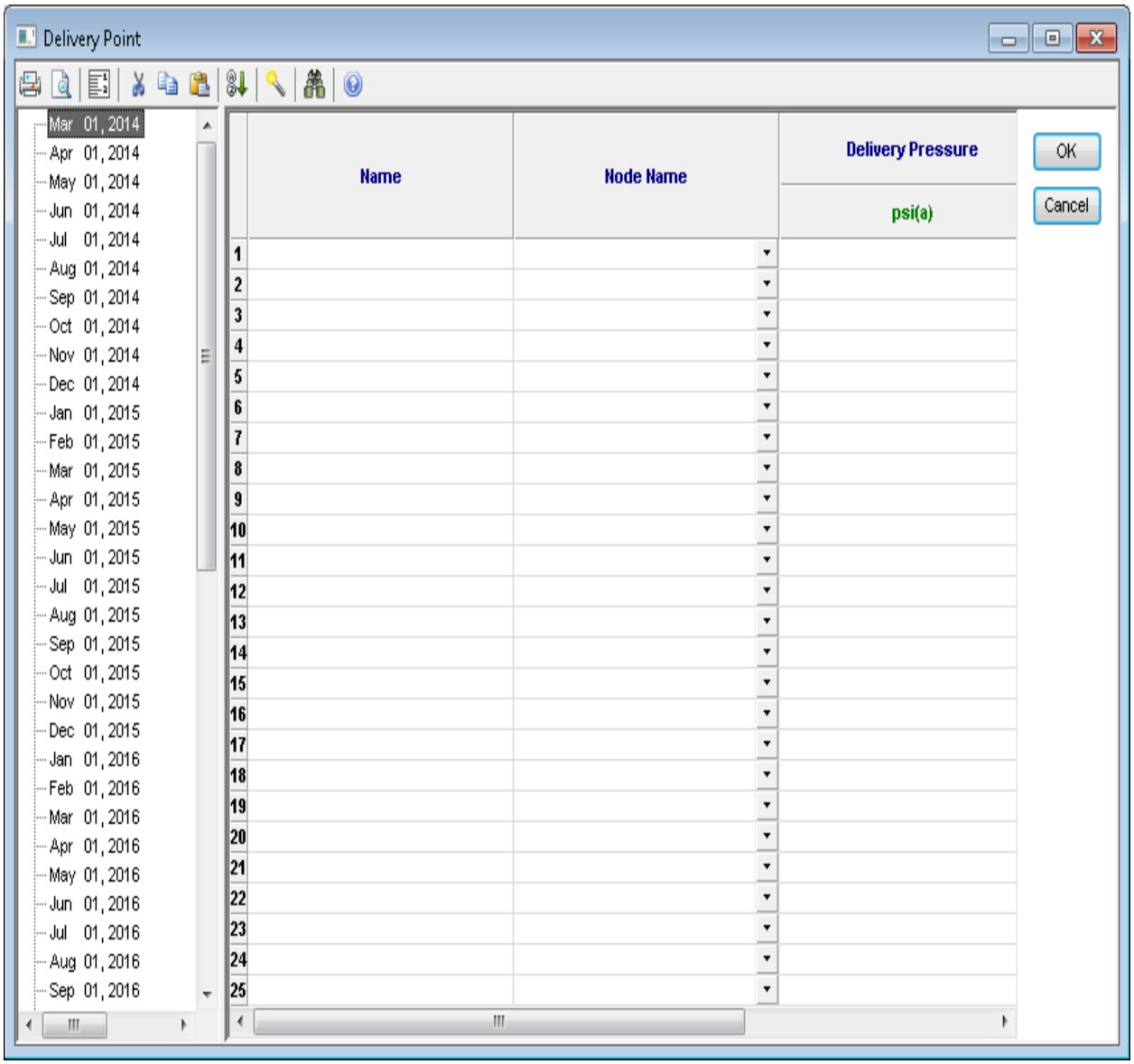
Most of the editors can be accessed from the menus, or by clicking the associated icon on the design toolbar.



Delivery Point editor 

Defining a delivery point is the first step in building a gathering system. When selecting the location of the delivery point, it is important to consider the objectives of the modeling work. Good locations for delivery points are custody transfer points, discharge or suction of compressors, or any other point where flowing pressures are expected to remain constant for the study period.

Click the standard gas processing plant icon  for delivery points in the gathering system, regardless of whether the delivery point is a plant, compressor, contract, sales meter, etc.



If you need to build a more complicated system containing two or more delivery points, you can specify each separate delivery point within the system in the Delivery Point editor. For a single file, you must define at least one delivery point, up to a maximum of 25 delivery points. For both GIS and Cartesian modes, you can create, modify, and delete delivery points in this editor.

Delivery point name

The delivery point name is the name given to the primary or starting node in a gathering system. By default, delivery point names are “Delivery Point 1”, Delivery Point 2”, etc. We recommend that you change your delivery point names to reflect specific locations in your system.

Note: You can adjust the node / facility naming convention in the facility name generator configuration.

Plant delivery pressure

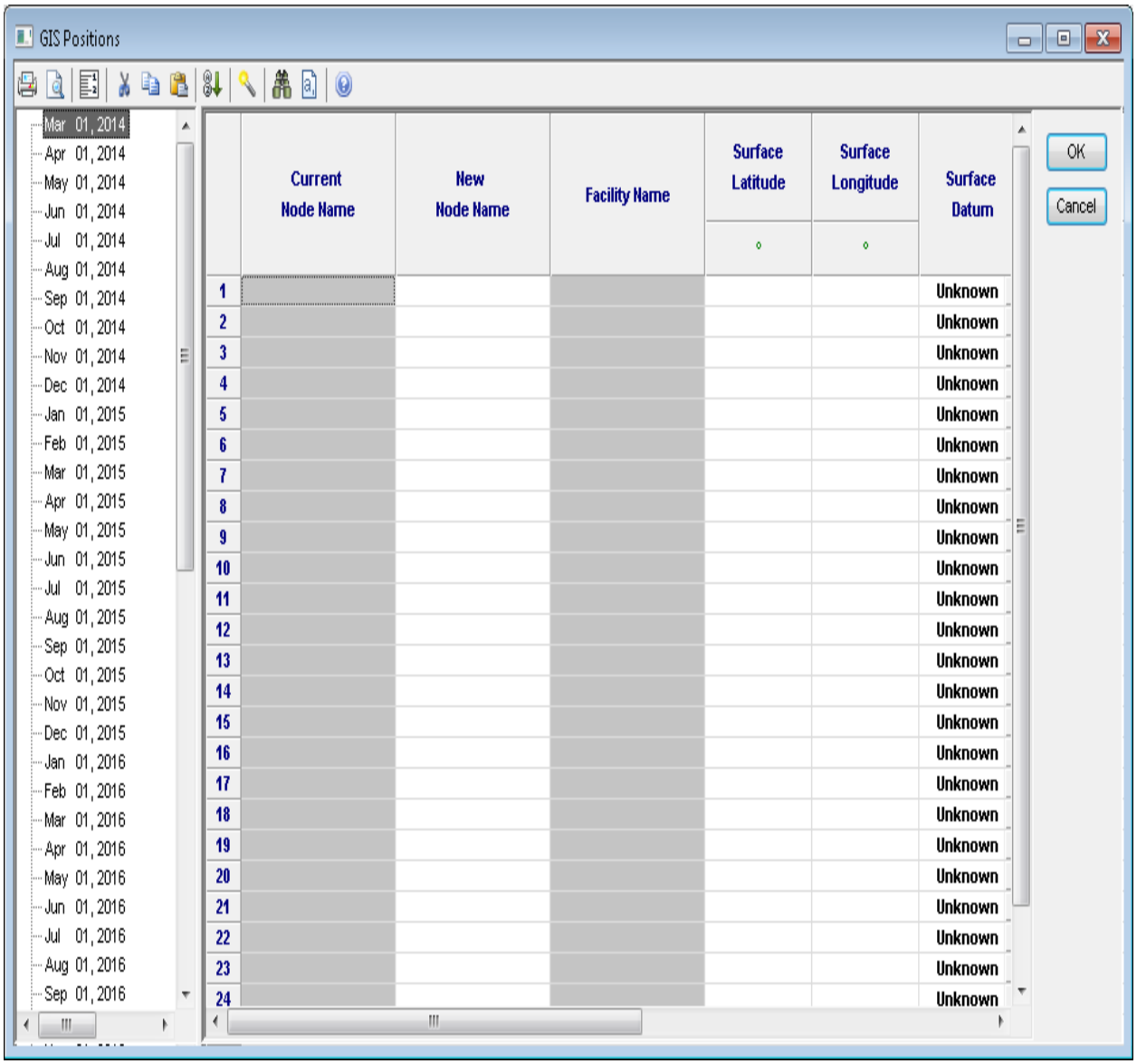
The delivery pressure is the pressure assigned to the outlet of the delivery point. Revise the default delivery point pressure of 900 psia (6205 kPaA) to reflect the delivery pressure of the system, or portion of the system being modeled. Note that the minimum allowable value for delivery pressure is 5 psia (35 kPaA).

This pressure can be scheduled through time to reflect seasonal delivery pressure variations or scheduled changes to compression suction pressure.

Note: Your model's pressure-loss calculations require appropriate delivery point pressures.

GIS Positions editor 

Use this editor to define location information for nodes in GIS mode. You can also attach nodes to facilities (for example, a well, compressor, separator, etc), but only one facility can be attached to a node.



In this editor, you can define the name of the node, along with the type of facility, if any, that is attached to that node. You can also define the coordinate systems (latitude / longitude, DLS, NTS, and UTM). If you would like to display other coordinate system data, right-click the columns with in the GIS Positions editor and select **Show Extra Location Columns**.

Note: Nodes that are attached to wells have a sandface location associated with them, and the sandface location can be different from the wellhead location.

These rules apply to this editor:

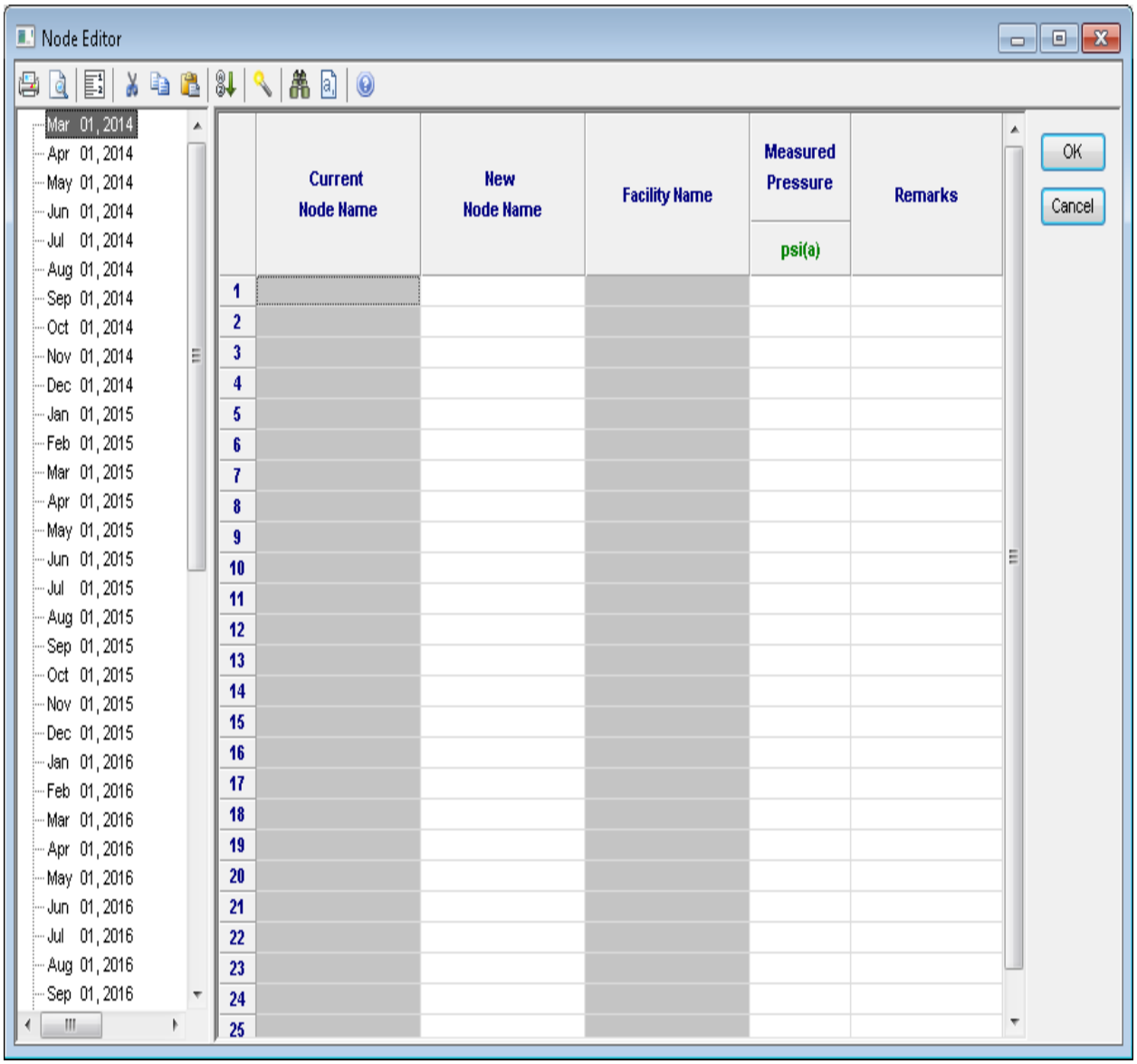
- In GIS mode, you can define a node in the GIS Position editor. Or, you can use the Gathering System editor, but the node is not assigned coordinates. To remove or

attach facilities to nodes, use the Facility editor.

- In GIS mode, you can only change the node name with the GIS Position editor. Changing the name of the node applies changes to attached facilities and gathering system linkages.
- If a change is made to any of the location coordinates for a node, other location coordinates for that node will be updated to reflect that change. (Changes override the existing location, regardless of which coordinate system the change is made for.)
- If changes are made to more then one coordinate system and those changes are inconsistent, the following hierarchy determines which coordinate system takes precedence :
    - Latitude/Longitude
    - UTM
    - DLS
    - NTS
- You can enter measured pressure values, so that you can compare forecasted values to determine if there are discrepancies between the actual pressure and the simulated pressure.
- Elevation values are entered in absolute values to convert the elevation differences in the Gathering System editor.

Node editor 

Use this editor to view and change node names and facilities attached to the node in Cartesian mode.

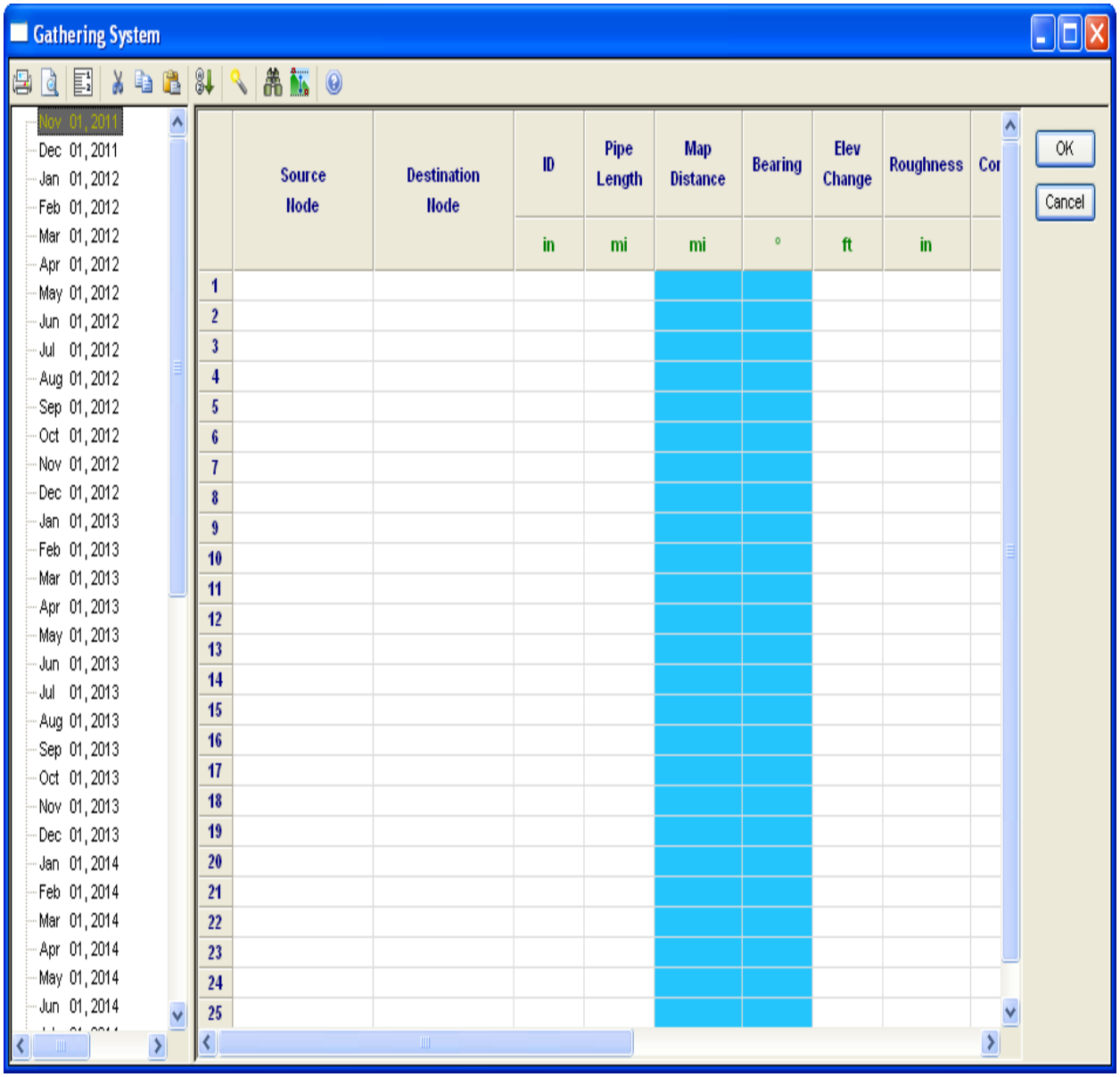


These rules apply to this editor:

- You can define nodes in the Node editor, or the Gathering System editor (provided that the node is linked to a node existing in the Cartesian space). To removing or attach facilities to nodes, use the Facility editor.
- In Cartesian mode, you can only change the node name in the Node editor. Changing the name of the node applies changes to attached facilities and gathering system linkages.
- You can enter measured pressure values, so that you can compare forecasted values to determine if there are discrepancies between the actual pressure and the simulated pressure.

Gathering System editor

This editor is used to create the overall superstructure of the gathering system. Once the structure has been defined, facilities (wells, compressors, etc) can be assigned to specific locations within the system.



When a row is highlighted blue, it has become disabled and becomes a thick black line on the GIS map. This happens when a loop has been formed but a valid Loop Link has not been designated. Designate a valid Loop Link or remove an invalid link and turn off the *Disable Link* flag.

(A) Required editor inputs

Source node

Starting point of a pipeline segment

Destination node

Endpoint of a pipeline segment

Pipeline length

A non-zero length is required for any pipeline segment. For more information, see pipe length vs. map distance.

Map distance (not accessible by the user)

The actual distance of the pipeline segment on the GIS map.

Bearing (accessible in Cartesian mode only)

Reflects the angle between the source and destination node that define the linkage. For more information, see bearing.

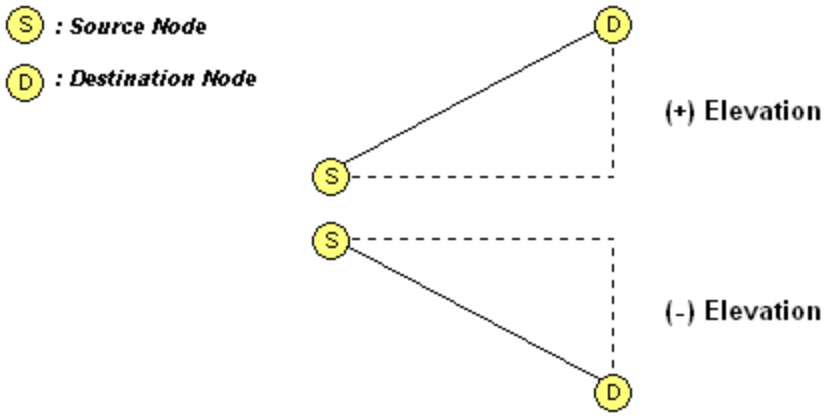
(B) Optional parameters

Pipeline ID

This is the inside diameter of a pipeline. If no pipeline ID is specified, Piper does not calculate a pressure drop along the length of the pipeline segment.

Elevation change

You may want to include topographical elevation changes in the case of hilly terrain, or when dealing with multiphase flow. The sign convention is shown below:



So, if the source node is lower than the destination node, then the elevation is positive(+). If the source node is higher than the destination node, the elevation is negative(-). The flow direction should not be considered when entering the elevation changes.

If there are absolute elevations entered in the GIS Positions editor, the elevation change can be automatically calculated by clicking the  icon in the Gathering System editor.

Pipe length vs. map distance

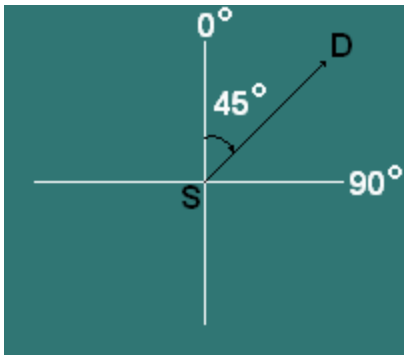
Because of the change to geodetic locations in Piper, the length column in the Gathering System editor has been replaced by two lengths: pipe length and map distance.

- **Pipe Length:** This is the length that is used to calculate the pressure loss in a pipeline segment. The pipe length can reflect the undulations and turns in the pipeline that may cause the true length of the fluid flow to differ from the geodetic distance between two points.
- **Map Distance:** This reflects the distance between the two nodes that define the link as is calculated from the latitude and longitude location of each node. You cannot change the map distance. If the latitude and longitude of a node is changed either on the map or through the GIS Position editor, the map distance will automatically update to reflect that change.

Bearing

Angles are assigned between two points using a polar coordinate system. The bearing reflects the angle between the source and destination nodes that define the linkage. Like map distance, the bearing is determined based on the geodetic location that defines the linkage, and cannot be changed in the Gathering System editor when in GIS mode. If the location of either of the nodes is changed, the bearing will automatically update to reflect this change.

Note: Bearing is defined based on 0 degree as true north.



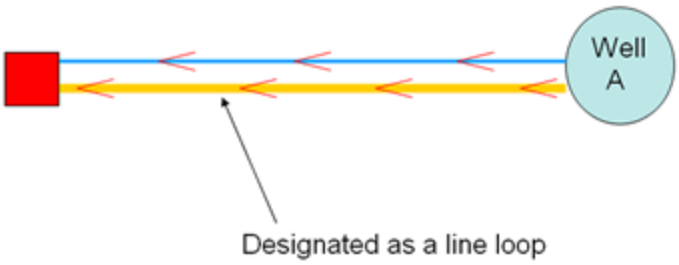
Loops

Incorporating line loops into a model can cause confusion with new users. Below is a brief description of looping with suggestions on how to incorporate loops into a model. If you need clarification, please contact us.

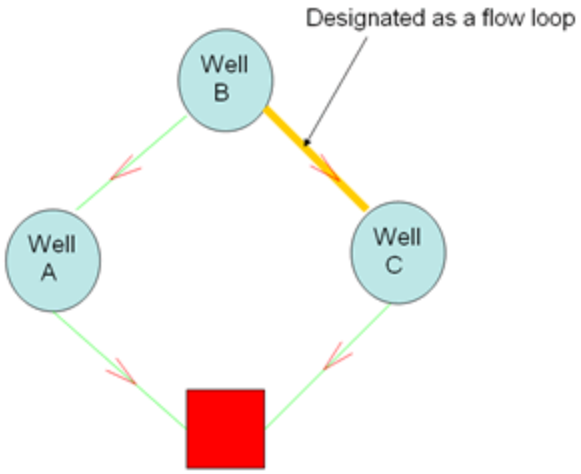
A pipeline loop provides an alternate route for gas to flow. Loops are installed in order to increase pipeline capacity. Two types of looping structures can be made in Piper: line loops and flow loops. In order to designate a line / flow loop, the line must be specified in the Gathering System editor using the columns below:

Looped: indicates if the pipeline segment is a loop
Unique ID: distinguish between various loop lines, if multiple loop lines are present.

Line Loop (twinning a line)

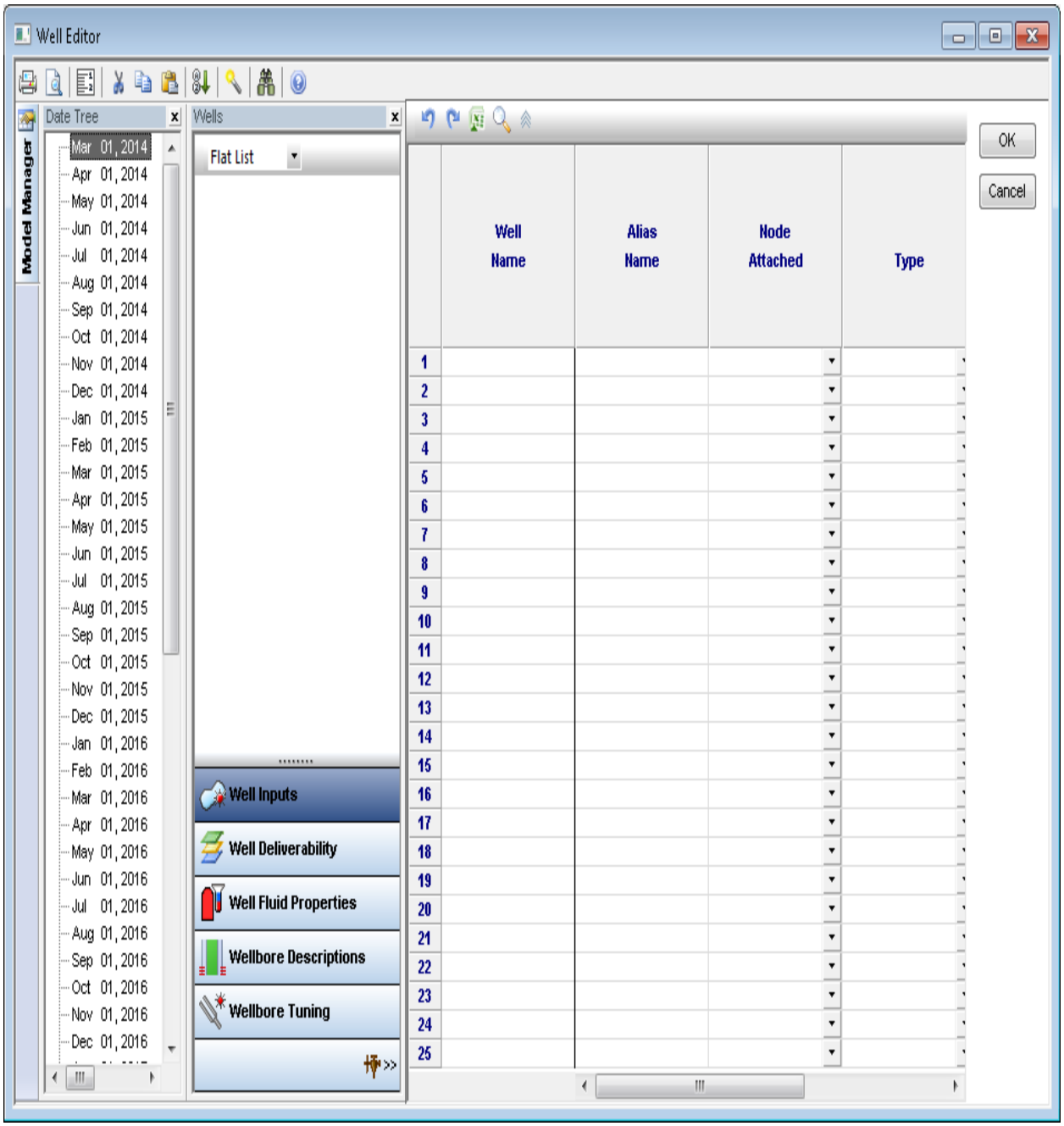


Flow Loop (alternate direction for gas to flow)



Well editor

This editor is used to specify how well production is modeled over time, and consists of three sections: Date Tree, Well Manager Model Manager, and the Well Viewer.



Date Tree: in this section, you can navigate through the configuration dates.

Wells Manager: in this section, you can view and navigate through the list of wells. At the bottom of this section, you can configure different parts of a well.

- Well Inputs
- Well Deliverability

- Well Fluid Properties
- Wellbore Descriptions
- Wellbore Tuning
- Well Options

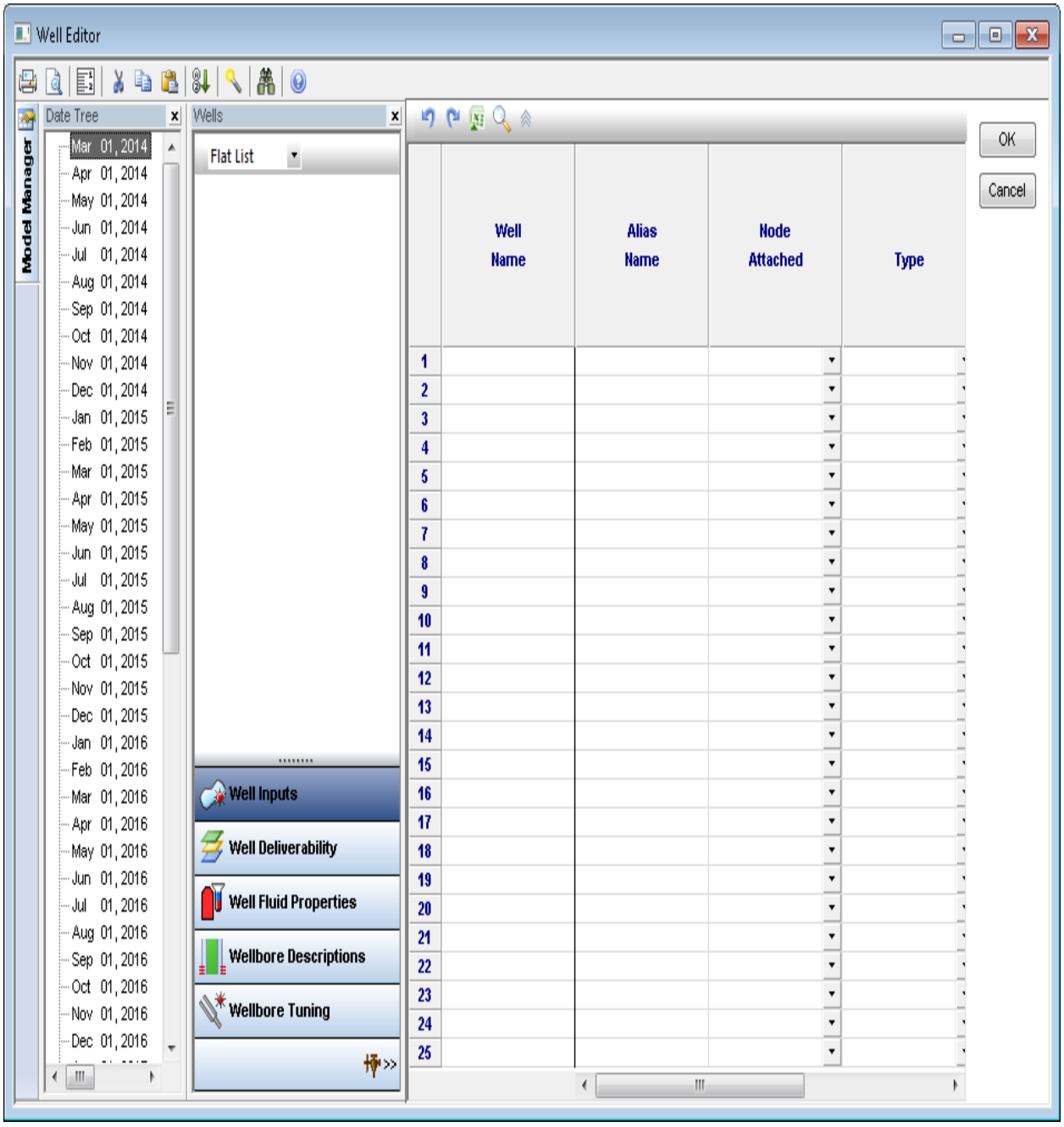
The Well Manager sorts the wells in the model using two options: Type and Flat List.



Well Viewer:in this section, you can control the data displayed in the Well Viewer editor.

Well inputs

If you use a well name that corresponds with a node name for the pipeline network, a well is created at that node location.



Well Name: the name of the well

Alias Name: an alternative name for wells, so that during importing Piper can update data.

Node Attached: wells can be assigned to existing nodes by clicking the drop-down arrow to the right of each field in the Node Attached column. A list of existing nodes is displayed. To assign a well to a node location, click the desired node name.

Or, a new node name can be defined in the Node Attached column. However, if you create a new node this way, you need to specify a location in the GIS Position editor.

If the node name is left blank, the deliverability data defined for that well remains in the Well editor, but the well is not located on-screen and exists as an unused facility.

Type: the performance of the well is determined by the type of well selected in the Type column. Deliverability options are assigned by clicking the drop-down arrow and selecting from the list. For more information, see Deliverability Options.

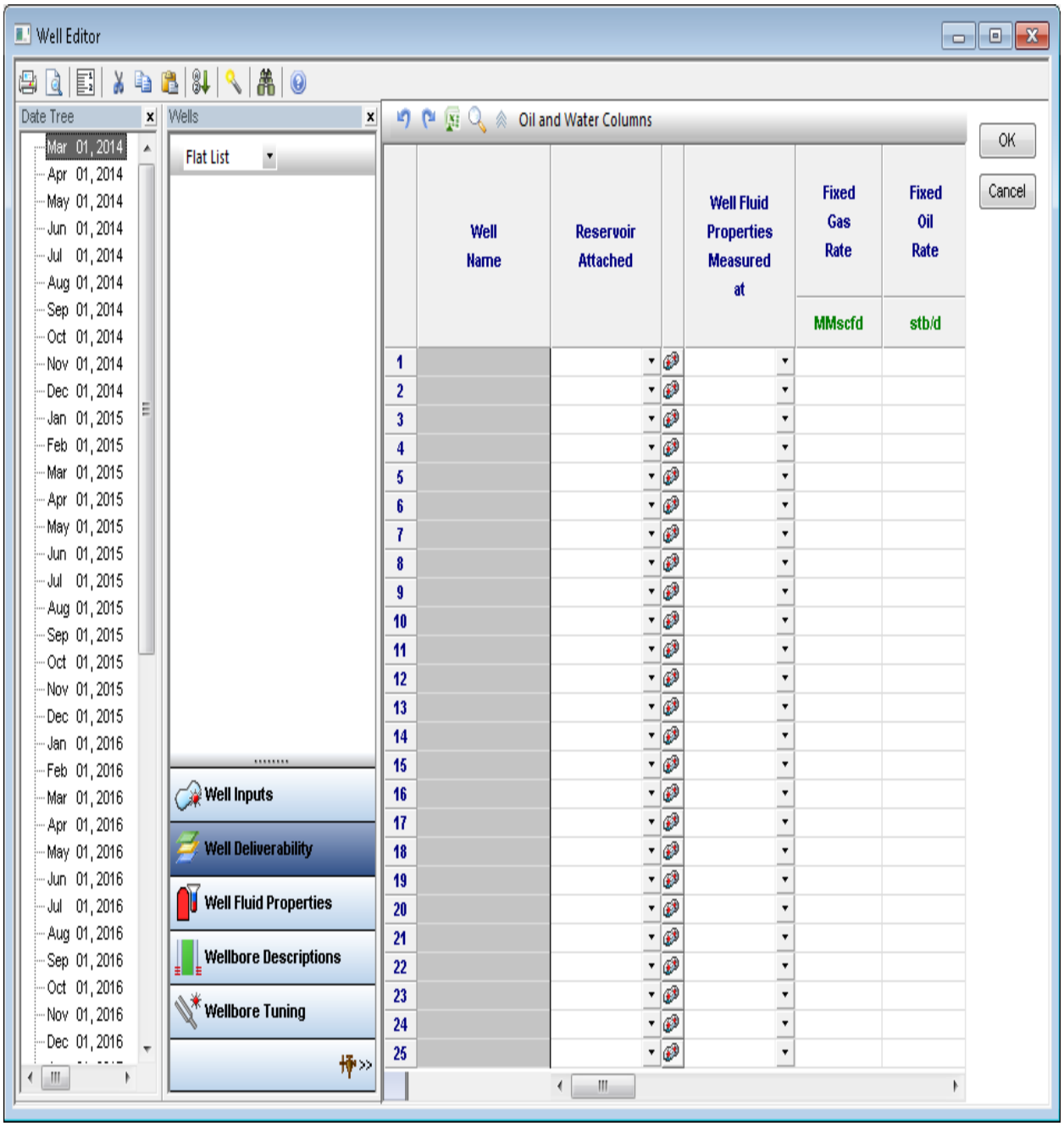
On-stream Date: you can create a well on one configuration date and activate it on a later date. When a well is on-stream it is displayed on the map as a colored well (), and a well that is off-stream is displayed as a gray well () on the GIS map. During forecasting, an off-stream well will not produce until it reaches it's on-stream date. If an on-stream date starts before the forecasting period, then the well is producing.

Note: Although a well can have an on-stream date before the forecast period begins, Piper does not calculate the deliverability of the well for the period before the forecast period. The well starts producing on the first forecast date, if the on-stream date is set before the forecast date.

Well deliverability

Well deliverability is used to specify how well production is modeled over time. Using a well name that matches a node name within the pipeline network results in a well at that node location. In Piper, deliverability is assigned on a well-by-well basis. The Type column in the Well Inputs editor is used to assign a type of deliverability for a well. For any selected delivery type, white fields indicate that data input is required, and fields that do not require input are highlighted in blue.

Reservoir Attached: some wells require an attached reservoir. You can assign a reservoir name to either an individual well or a group of wells by clicking the drop-down arrow to the right of each field in the Reservoir Attached column. To assign a reservoir to a well, click the appropriate reservoir name.

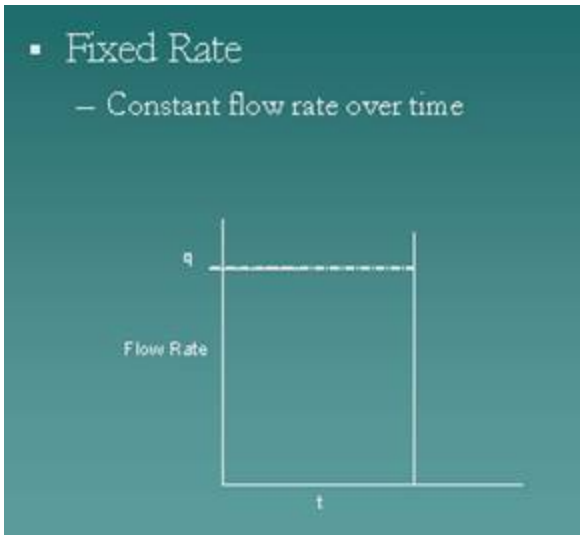


Deliverability options

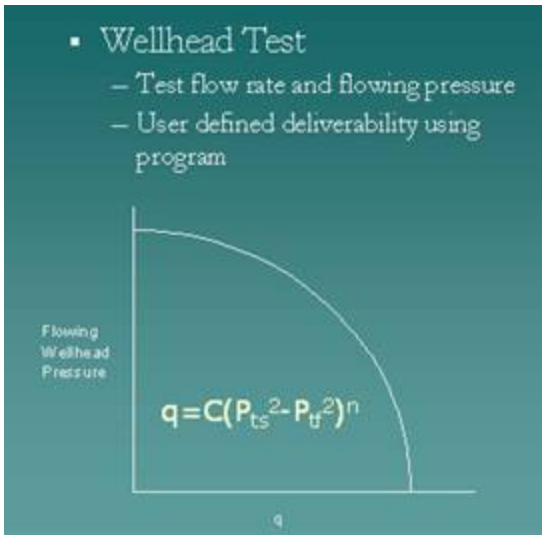
These are the main categories for defining the deliverability of a well:

1. **Fixed Rate** - defines the deliverability of a well as a constant gas rate over time. The gas rate remains fixed despite changes in reservoir or pipeline pressures. Note that a reservoir does not need to be designated to a fixed rate well. However, if a reservoir is assigned to a

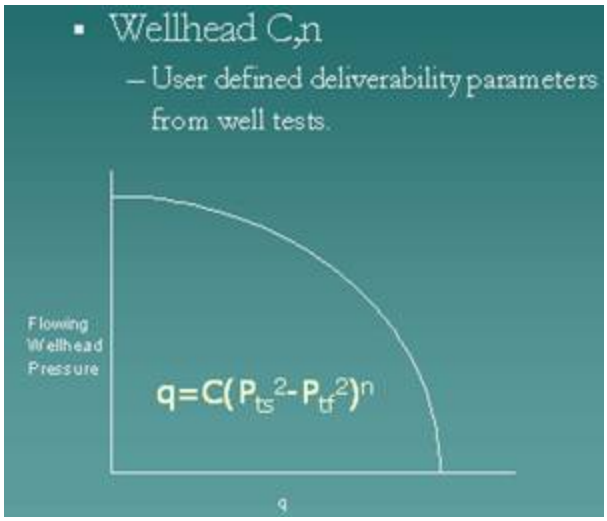
fixed rate well, the well produces at the specified gas rate until the reservoir volume is depleted.



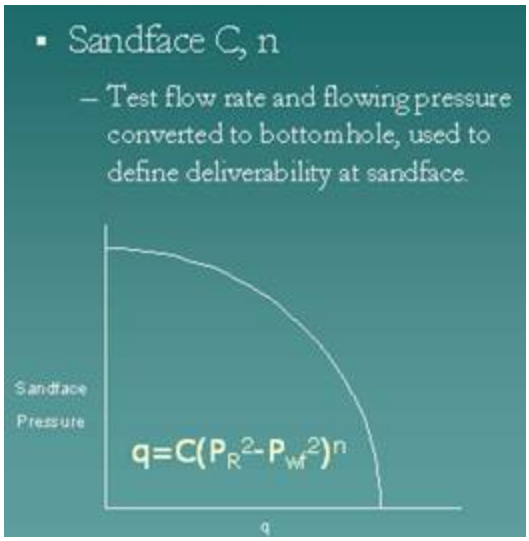
2. **Wellhead Test** - defines the deliverability of a well at the wellhead. A flowing wellhead gas rate, corresponding flowing pressure, and wellhead 'n' value are required for input. In addition, a reservoir must be assigned to the well.



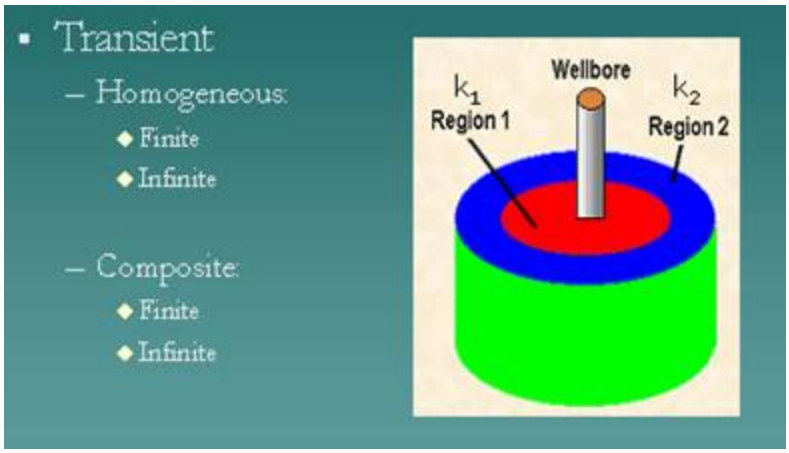
3. **Wellhead C, n** - defines the deliverability of a well at the wellhead. A wellhead 'C' and wellhead 'n' value are required for input. These parameters are available from AOF / back-pressure / deliverability tests. In addition, a reservoir must be assigned to the well.



4. **Sandface C, n** - defines the deliverability of a well at the sandface. A sandface 'C' and 'n' value are required for input. These parameters can either be entered (from deliverability test information), or they can be calculated in the Wellbore Tuning editor.



5. **Transient** - defines the deliverability of a well by selecting one of the various simplified analytical reservoir models. The required inputs for transient wells are completed in the analytical well editors. See Analytical Models for more information.

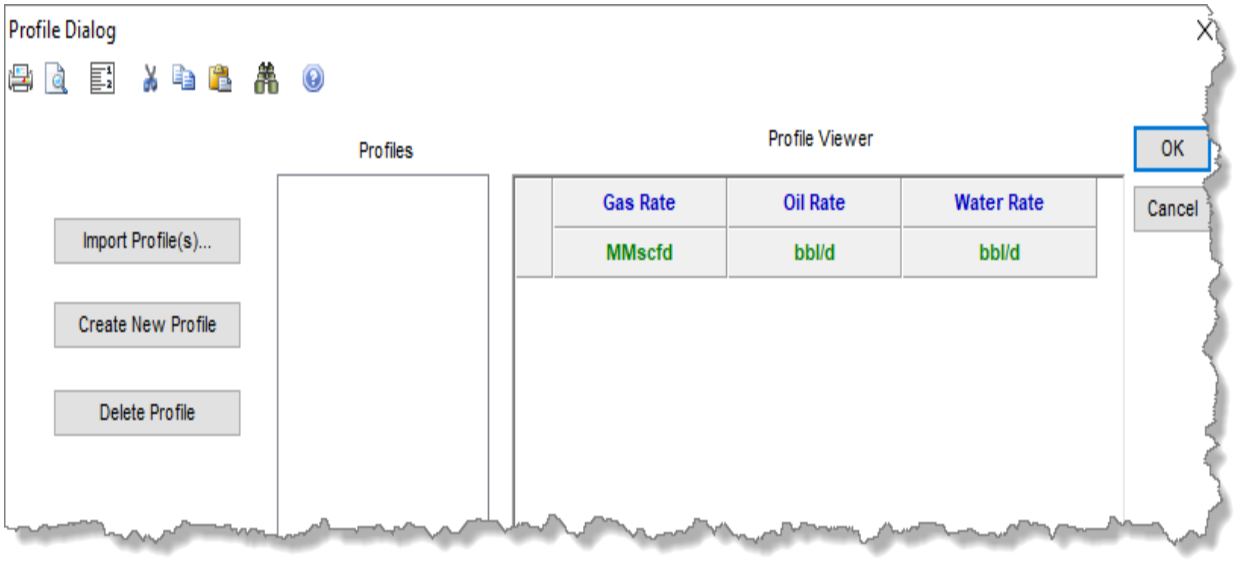


6. **Profile** - defines the well deliverability through time based on user-supplied production decline profiles. A well modeled using this option produces according to the user-defined trend and is not affected by changes in well back pressure. You must enter the profile name in the deliverability editor, and this name must first be defined in the Profile editor. For more information, see Profile Editor.

   For a more detailed description of modeling and options, see wellbore tuning for sandface deliverability wells.

Profile editor

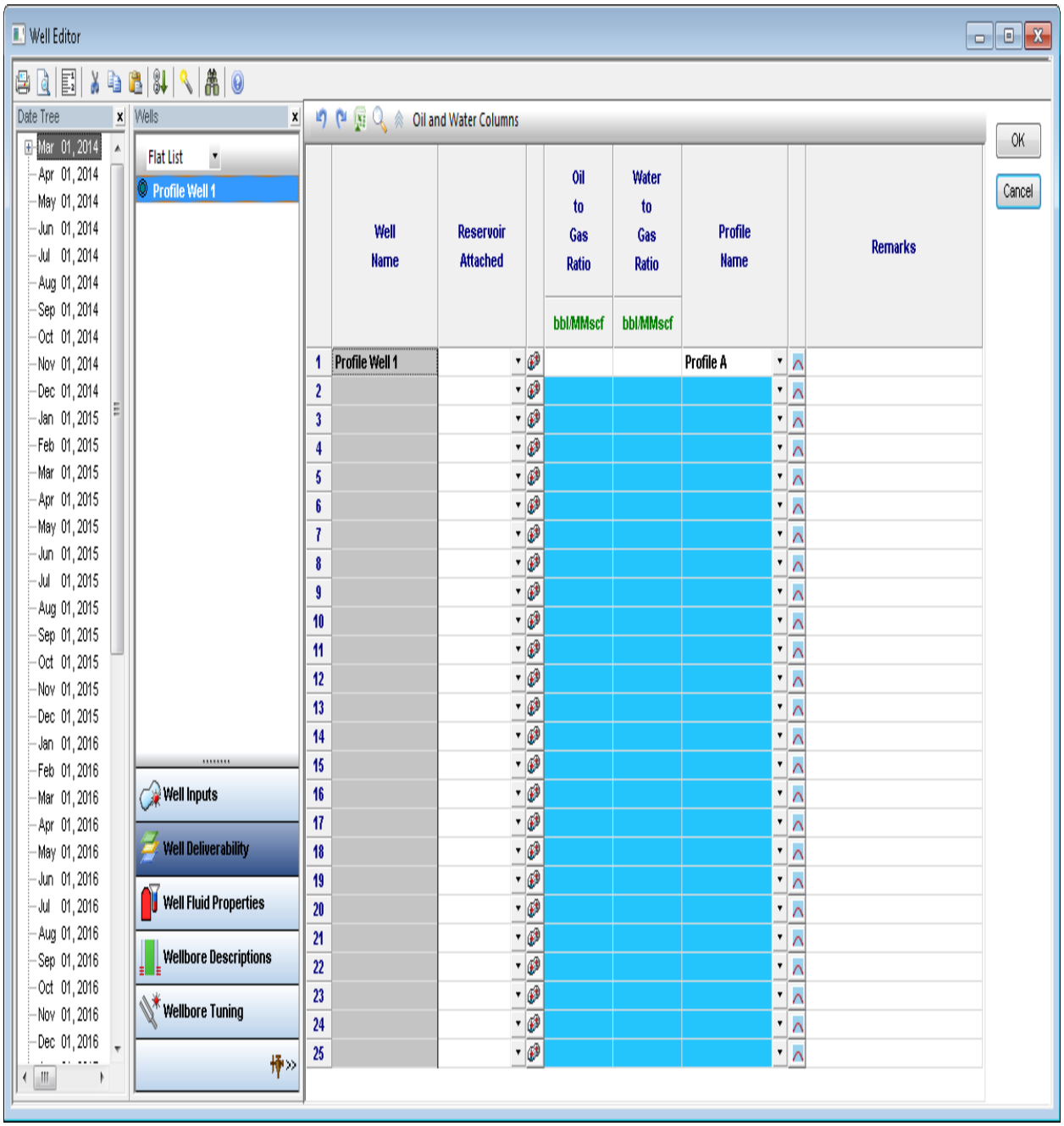
To open the Profile editor, click the **Profile** icon ( ) in the Profile column. (You may have to scroll horizontally to see this column in the table.) In this editor, you can create or import a production profile, which can be assigned to an individual well.



To create a new production profile, click the **Create New Profile** button. The following inputs are required:

- **Profile name**
- **Gas rates and Liquid rates** — can be entered in the Profile Viewer, or content can be brought in from an Excel file.

A production profile can be imported from an existing .csv, .txt, or .xlsx file by clicking the **Import Profile(s)** button and specifying the file to import. After a profile has been made, it can be assigned to the appropriate well(s) in the Well Deliverability Editor. We recommend selecting the Profile option in the Well Deliverability editor, and assigning a profile name from the drop-down menu.

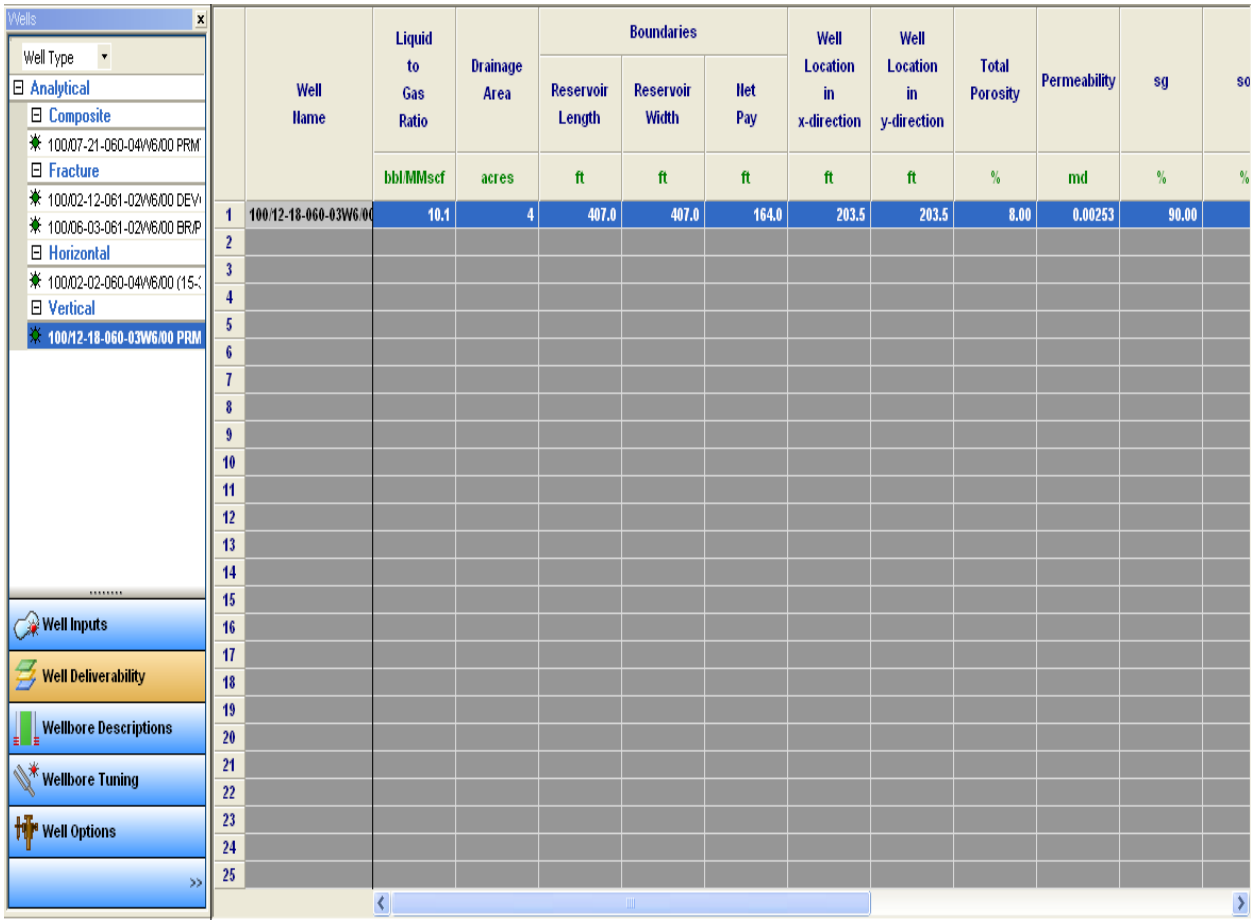


Analytical models

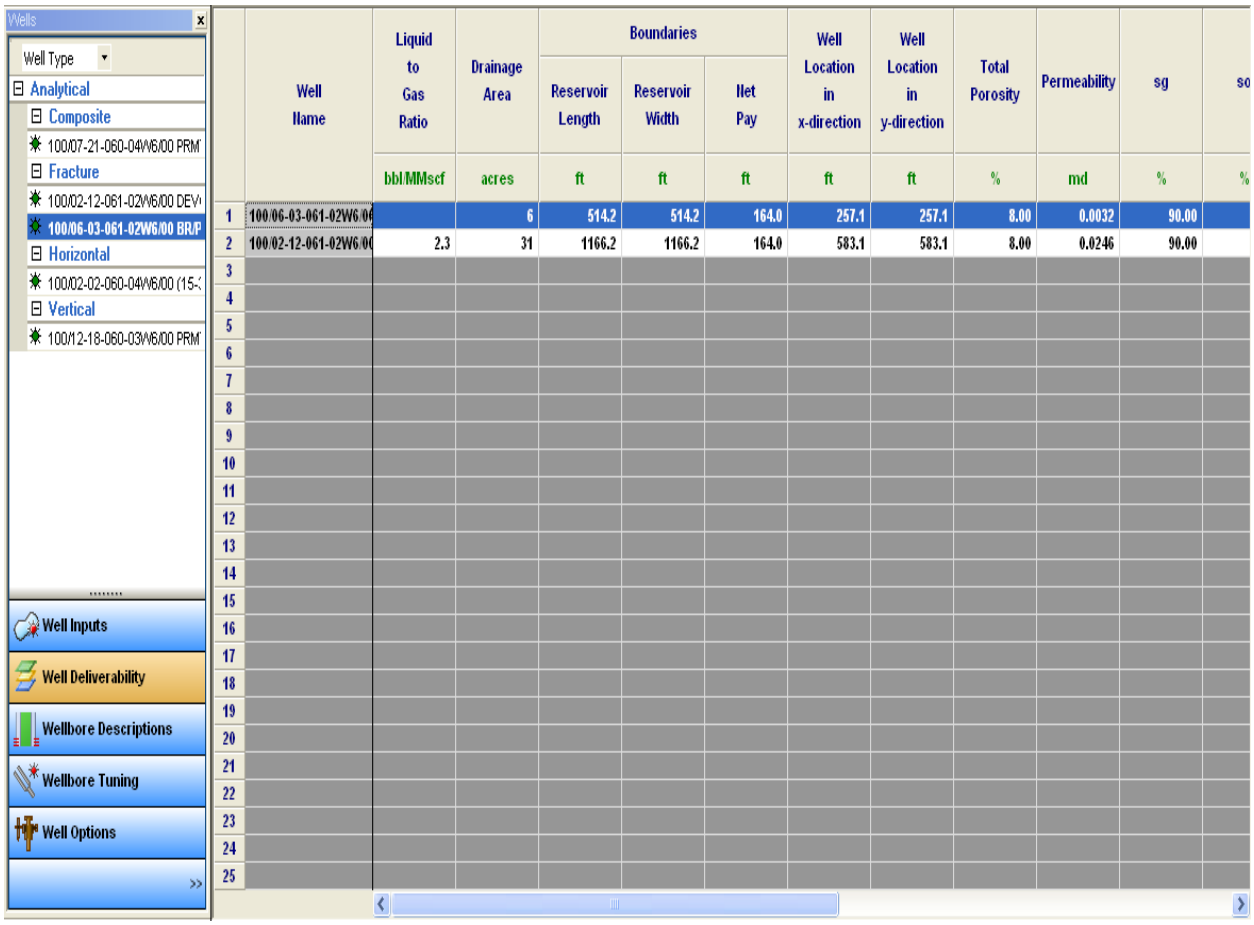
Analytical models are used to predict reservoir deliverability. To use this editor, assign a well a transient deliverability in the Well Inputs editor. The required inputs are shown in white.
There are five types of analytical models, and the Well Editor has a different table / grid for each model.

1. **Legacy Transient:** The legacy transient models consists of four different model types. These model types are simplified approximations of the rate transient analysis (RTA) analytical models of the same type. Specifically, the legacy models do not consider the effect of superposition of pressure. Therefore, these models could be expected to under predict the rate changes caused by changes in pressure.

2. **Vertical:** represents a vertical well in a rectangular, homogenous reservoir.

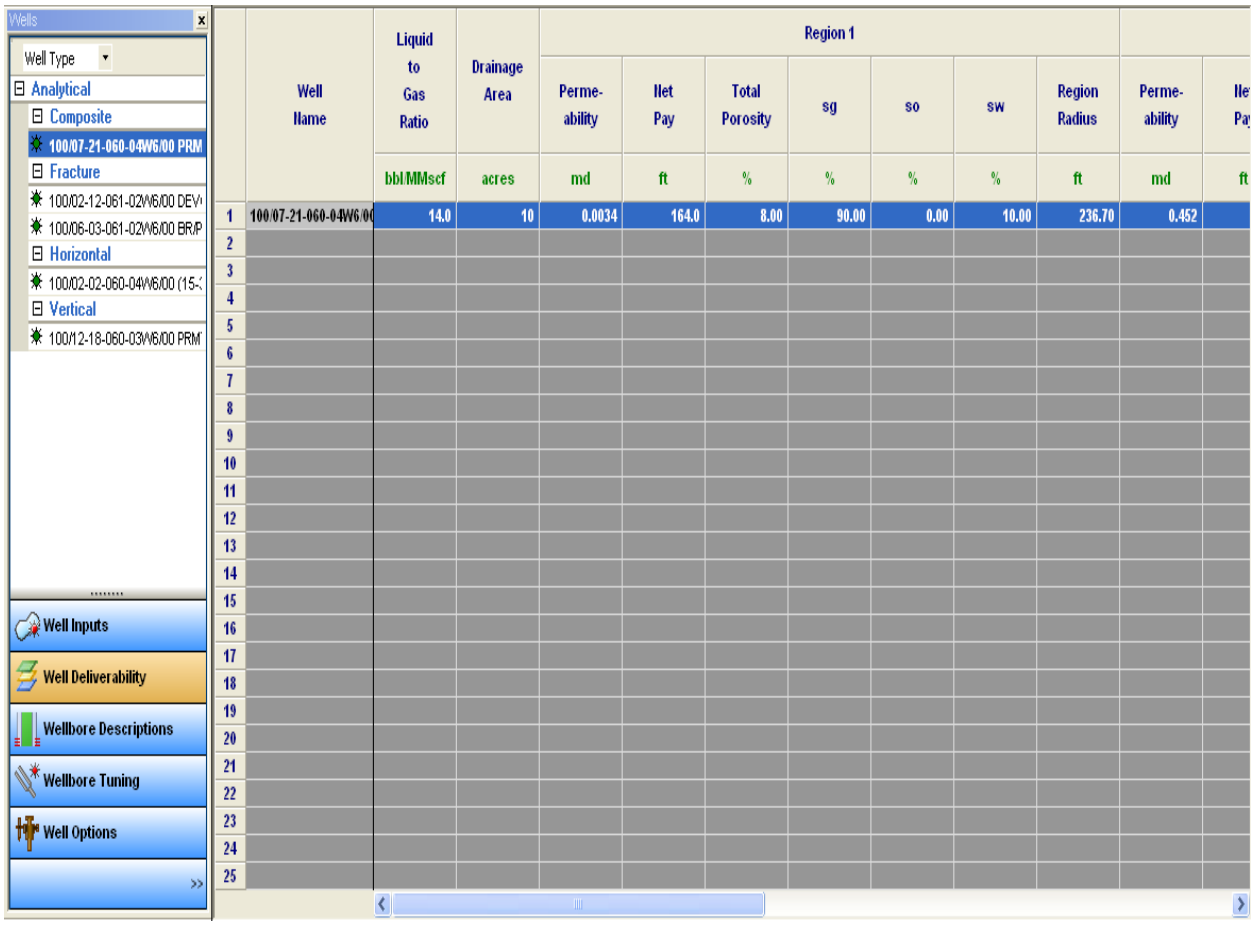


3. **Fracture:** represents a model of a single fracture off a vertical wellbore in a rectangular reservoir.

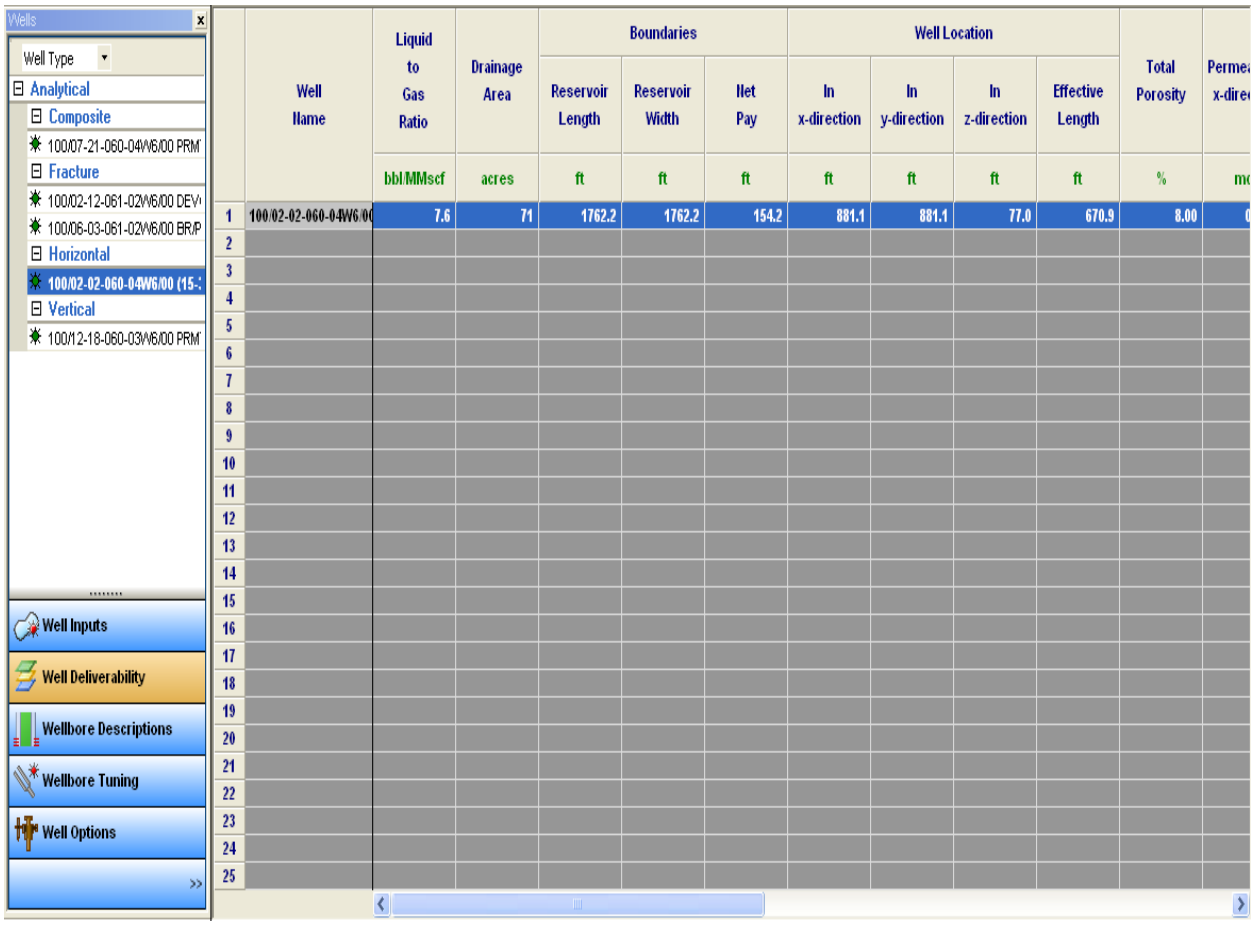


	Well Name	Liquid to Gas Ratio	Drainage Area	Boundaries			Well Location in x-direction	Well Location in y-direction	Total Porosity	Permeability	sg	so
				Reservoir Length	Reservoir Width	Net Pay						
		bbl/MMscf	acres	ft	ft	ft	ft	ft	%	md	%	%
1	100/06-03-061-02W6/0		6	514.2	514.2	164.0	257.1	257.1	8.00	0.0032	90.00	
2	100/02-12-061-02W6/0	2.3	31	1166.2	1166.2	164.0	583.1	583.1	8.00	0.0246	90.00	
3												
4												
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4. **Composite:** represents a vertical well in a circular reservoir with an inner circle with one set of properties and an outer circle with another set of properties.



5. **Horizontal:** represents a single horizontal leg off of a vertical wellbore in a rectangular reservoir.



For each option, you must enter an on-stream date and reservoir parameters.

For more information on the parameters used to define each well type, see the Analytical Model.

Well fluid properties

The Well Fluid Properties editor's table / grid is accessible from the Well editor.

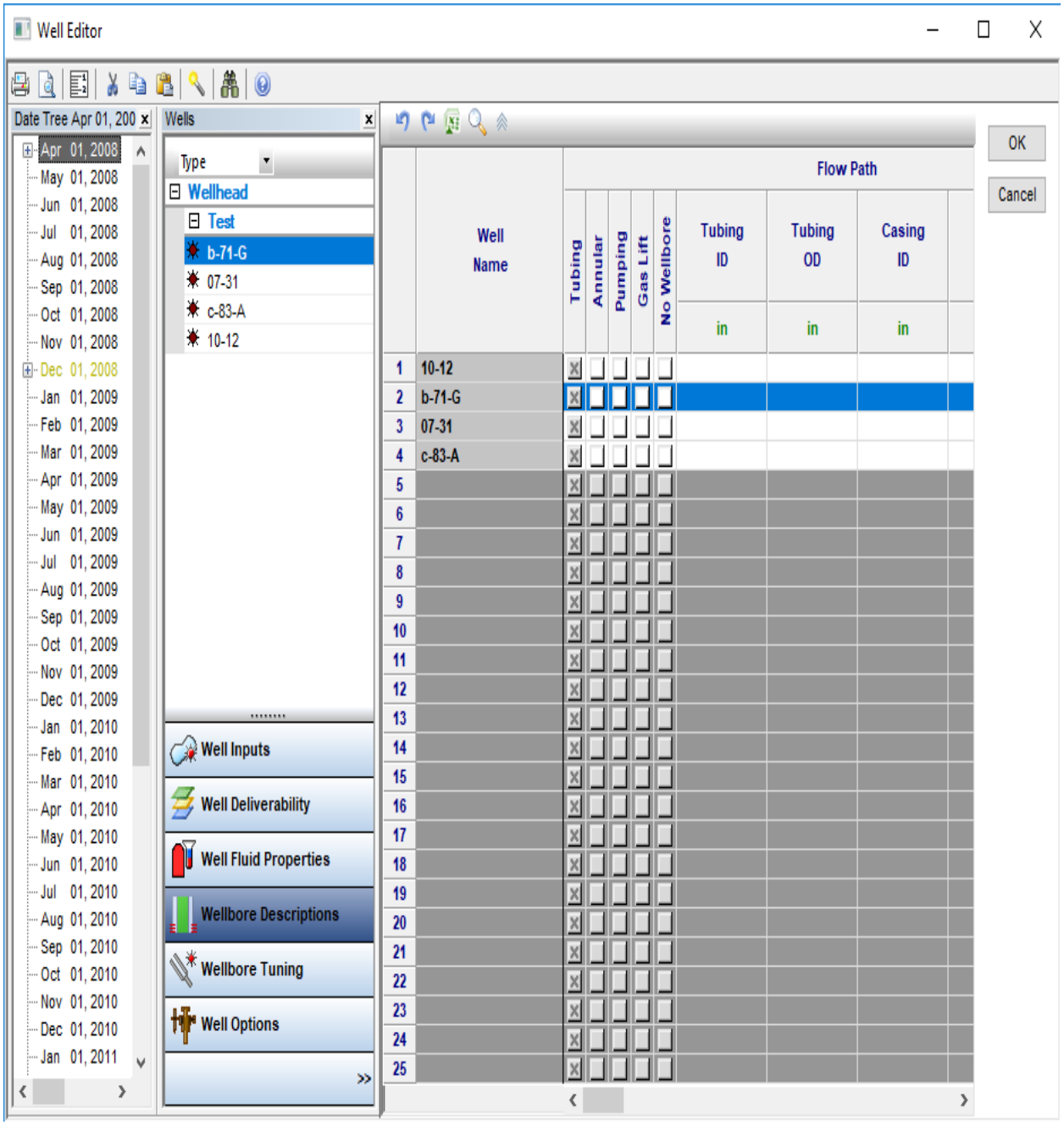
The contents of the well fluid properties depend on whether you have selected Black Oil, Peng-Robinson / Wilson, or for no-phase volume calculations to be performed.

For more information on how to use well fluid properties, see Defining Compositions.

Wellbore descriptions

With this editor, you can:

- Specify the type of completion
- Enter wellbore dimensions
- Model wellbore loading and pumping
- Select a correlation for calculating wellbore pressure losses



For any option selected in this editor, white fields indicate required inputs, and blue fields indicate parameters that are not required. To model a wellbore in Piper, you have five major options available:

1. **Tubing**

   This option requires you to enter the tubing inner diameter (ID) and outer diameter (OD), along with the casing ID. You must also enter end of tubing (EOT) and the mid-point of perforations (mpp). With these values entered, wellbore calculations take place along the tubing until EOT is reached, and then either up to mpp in the annulus, or down to mpp in the casing. The wellhead pressure is determined from the surface gathering system. You can also specify the wellbore pressure loss correlation, if you want to change it from the default value.

   Note: With Piper, it is assumed that tubing exists in your well. If your well does not have tubing (i.e., casing-only flow path), we recommend that you enter your actual casing inner diameter as "Tubing ID", and then enter larger dummy values for "Tubing OD" and "Casing ID".

2. **Annular**

   This option requires you to enter a tubing ID and outer diameter OD, along with the casing ID. You must also enter EOT and mpp. With these values entered, wellbore calculations take place along the annular flow path until mpp is reached. If mpp is deeper than EOT, then wellbore calculations take place along the annulus until EOT, and then use the casing diameter to mpp. The wellhead pressure is determined from the surface gathering system. You can also specify the wellbore pressure loss correlation, if you want to change it from the default value.

3. **Pumping**

   Piper uses the pumping flow path in a similar way to Harmony and Harmony Enterprise. In general, gas is assumed to flow up the annulus, while liquid is pumped up the tubing. Since there is no ability in Piper to calculate the pressure drop across the pump (in the tubing), all wellbore pressure loss calculations are performed in the annulus / casing. This is done in two stages:

   - Stage 1: calculates the pressure drop from the wellhead to the liquid level using a single-phase gas method
   - Stage 2: calculates the pressure drop from the liquid level to mpp using a gradient calculation

   Note: The liquid level is entered using the Fluid Column Height.

   - **Fluid Column Height** — this is the constant height of the fluid column above the EOT, and it is needed to maintain proper pump operation. You can edit the default value of 250 ft.

- **Gasified Liquid Column Gradient** — this parameter is used to calculate the back pressure imposed on the formation by the column of fluid you previously specified. You can edit the default value of 0.265 psi / ft.

The pumping flow path can be enabled either at the beginning of a well's life, or after liquid loading begins. For the latter option, you want to choose a Liquid Lift Correlation, and then Submersible pump as the method used after the well loads.
By default, Piper assumes that the wellhead pressure obtained from the surface gathering system is the casing / annulus wellhead pressure for the pumping flow path. If the surface gathering system is connected to the tubing output, you need to manually enter the wellhead pressure at the casing / annulus. If so, enable Use Casing Pressure and then enter the pressure you want for wellbore calculations.

4. **Gas Lift**

Piper uses the gas lift flow path in a similar way to Harmony and Harmony Enterprise. In general, this flow path is related to the tubing flow path described earlier, but with additional gas in the tubing part of the wellbore. The math can be described in two stages:

- Stage 1: calculates the pressure drop from the wellhead to EOT using both reservoir gas and injected gas-lift gas, along with any liquids produced by the reservoir.
- Stage 2: calculates the pressure drop from the EOT to mpp using exclusively the reservoir fluids.

The injected gas lift rate can be set in one of two ways:

a. Using a Gas Lift Profile

- Requires you to enable a Use Gas Lift Profile (this profile must be created and selected in the drop-down list). Creating a gas lift profile is similar to creating a production profile for a Profile Well.

- When you enable this feature, Piper adds the gas lift profile rate for each time step to the produced rate for that same time step.

b. Using a Gas Lift Gas Rate Factor

- Requires you to enter a Gas Lift Gas Rate Factor, and select a liquid lift correlation from the drop-down list in the Liquid Lift Correlation column.

- When you enable this feature, Piper calculates the minimum rate necessary to lift liquids, and multiplies that rate by the entered Gas Lift Gas Rate Factor.

- The calculated gas lift rate is then added to the produced gas rate.

Note: The gas gravity of the injected gas-lift gas uses the default value of 0.65. You can change this by clicking the Gas Lift Compositions icon.

5. **No Wellbore**

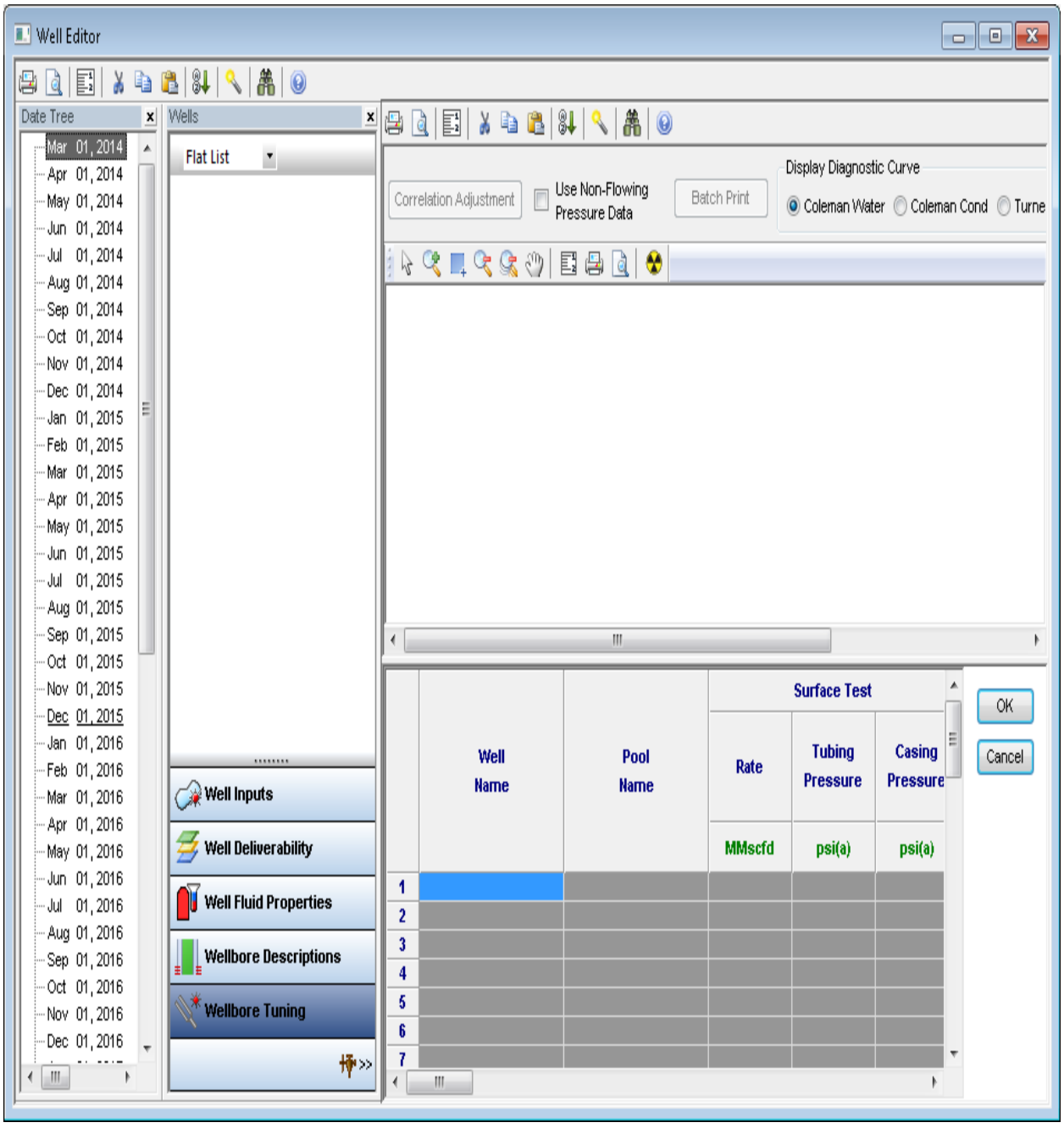
Piper has an option to ignore the frictional and liquid pressure losses. With this option, Piper only considers a static gas column within the wellbore. This option is intended to mirror the results for wells imported from previous versions of Piper where the wellbore was not specified.

If you choose to use No Wellbore, the only inputs this option requires are the mpp and the single-phase correlation. Sandface pressure is calculated assuming static gas from the surface to mpp.

For a more detailed description of modeling and options, see Wellbore Tuning Reference Materials.

Wellbore tuning 

With this editor, you can create and modify the parameters for sandface wells.



To create a Sandface Deliverability well, enter either input a Sandface 'C' and 'n' value directly, or enter a Surface Test Pressure, Test Rate, and Liquid to Gas Ratio (LGR), from which Sandface 'C' can be calculated. If you do not specify an n value, a default value of n = 1 is applied.

This editor has following additional functionality:

- Enter and adjust Wellbore Flow Path dimensions. Or, Wellbore Flow Path dimensions entered in the Wellbore Description editor will be automatically retrieved.

- Use the Turner or Coleman liquid lift correlations to determine the ability of the well to lift liquids to surface and simulate metastable flow rates after the onset of loading.
- Adjust the Gasified Liquid Gradients in the Casing and Tubing / Annulus to tune the well to the desired post liquid loading performance.
- Automatically switch a well that becomes unable to lift liquids to artificial lift.

Methods of using the wellbore tuning editor to calculate sandface C

If the sandface deliverability of a well is known, you can enter it in the Sandface C field. If the sandface deliverability is not known, the deliverability can be calculated in different ways:

- If the well is able to lift liquids the C-value can be calculated from flowing wellhead conditions
- If the well is not able to lift liquids, the C-value can be calculated from non-flowing side wellhead conditions

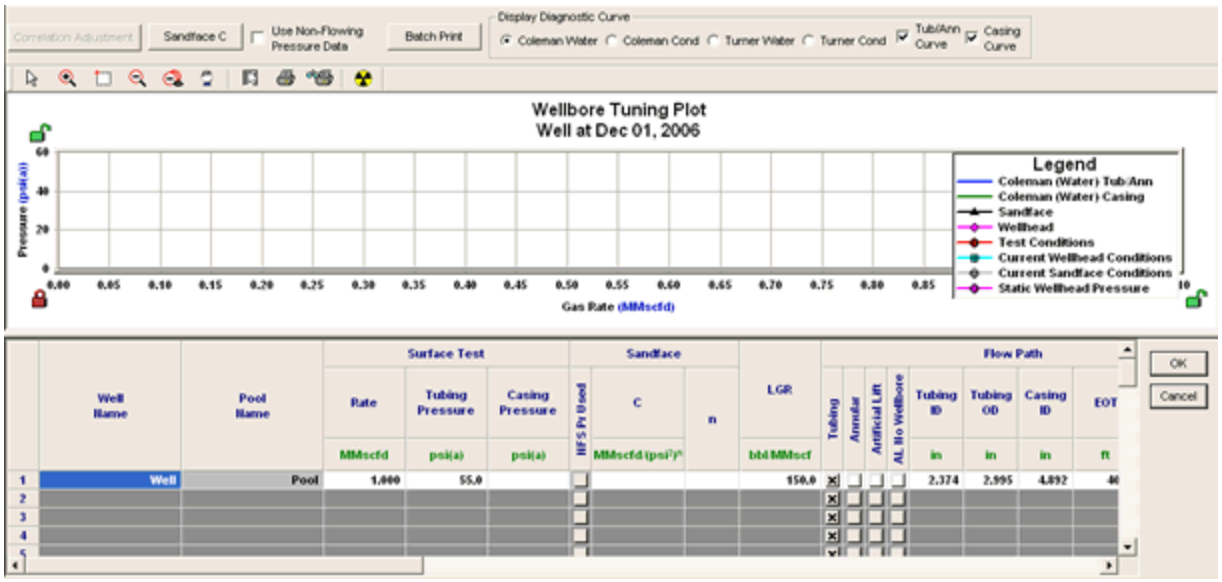
If the C-value is known but the well is not able to lift liquids, the C-value can be matched to current flowing wellhead conditions by allowing Piper to adjust the effect of liquids in the wellbore. Various scenarios are outlined below.

We recommend that you start with the first scenario (1). If you determine that the well is liquid loaded, move onto steps (2), or (3) depending ion f non-flowing side pressure data is available, or if a C-value from an unloaded flow test is available.

Scenario 1

The well is able to lift liquids and the C-value can be calculated from flowing wellhead conditions

A. We have the following production data for a well: wellhead flow rate, flowing side pressure, and LGR. Enter these values into the Wellbore Tuning editor, select the appropriate flow path and enter other wellbore parameters, such as the Tubing and Casing ID and depths.

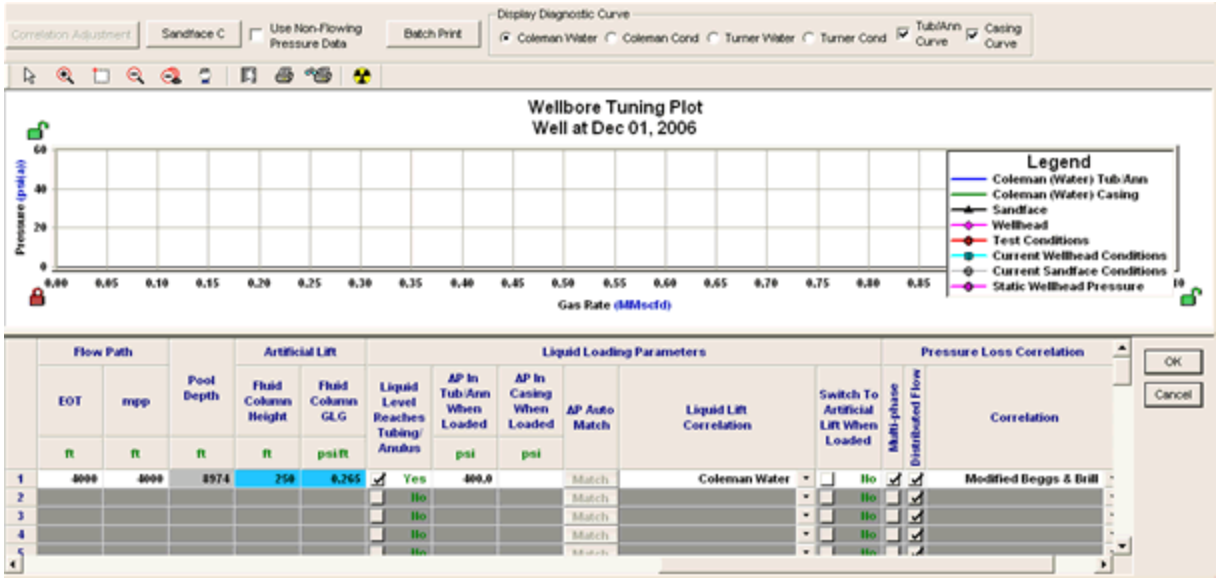


If liquid loading is not considered, proceed to step 2, and note that the pressure drop in the wellbore will be calculated by the single or multiphase correlation in all cases.

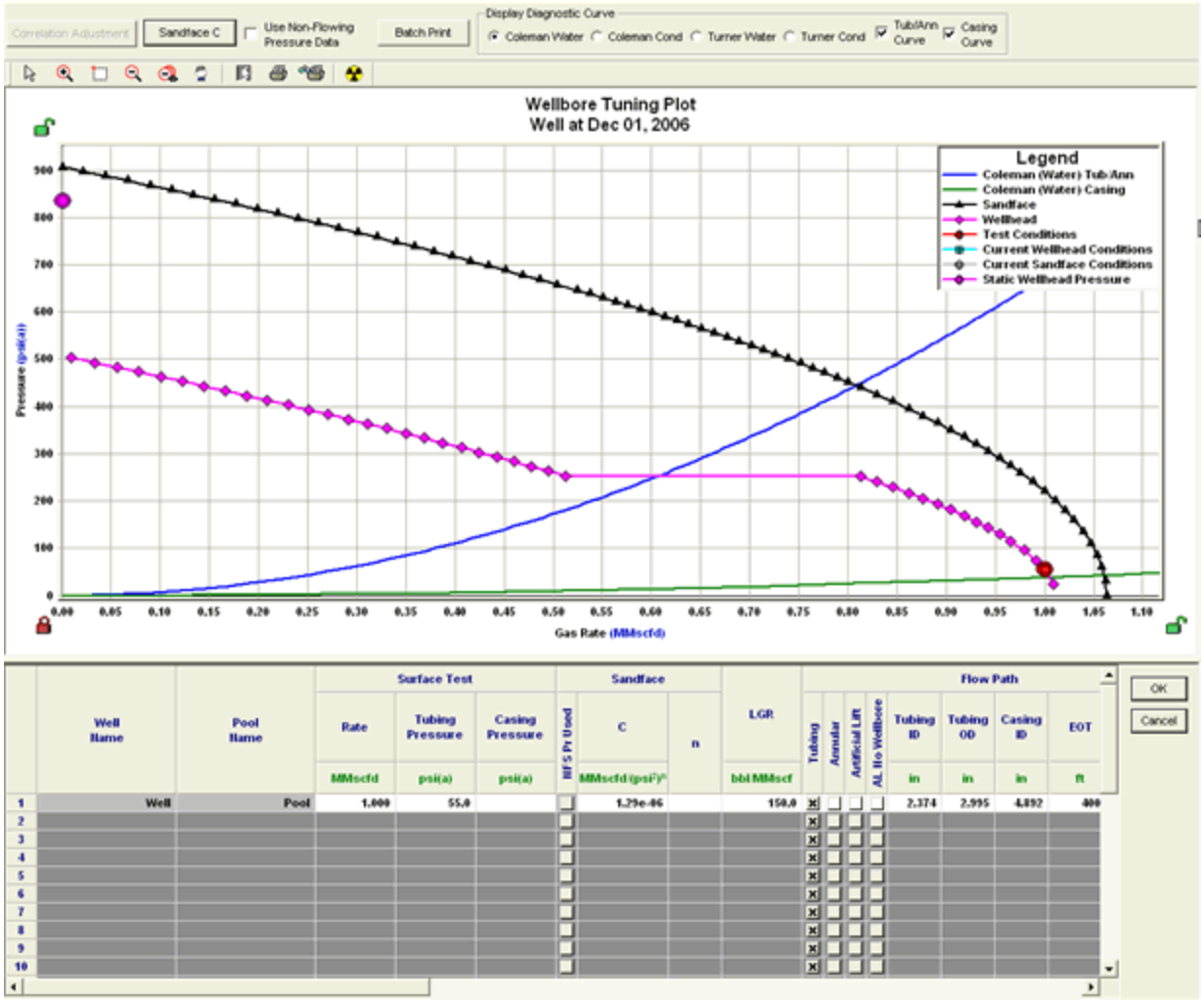
If liquid loading should be considered, under the heading Liquid Loading Parameters, select the liquid lift correlation that will be used to predict when the well will load. For more detail on how to choose between the possible correlations, see Sandface C calculations.

The column toggle labeled "Liquid Level Reaches Tubing / Annulus" determines whether a liquid column will form within the tubing / annulus once the well can no longer lift liquids within this segment. For some wells where the perforations are located far below the end of tubing, a liquid column will not reach to the tubing / annulus even after the well can no longer lift liquids.

If it is likely that liquids will accumulate in the tubing, make sure to select the checkbox in the column Liquid Level Reaches Tubing / Annulus . In this case, when the well can no longer lift liquids in the tubing the pressure drop defined by the "ΔP in Tub / Ann When Loaded", the column will be applied to the well. However, if the difference between the EOT and MPP is large and it is therefore likely that liquids would accumulate in the casing and never reach the tubing ensure that it says in the column Liquid Level Reaches Tubing / Annulus, then select the Liquid Lift Correlation to use. Scroll to the right and select Multiphase flow, if applicable; then select the appropriate correlation.



B. Finally, estimate an n-value to account for near wellbore turbulence. For rate wells, an n value close to or equal to 1 should be used. For high flow rate wells, where high velocities in the near wellbore region could be expected to cause additional pressure losses due to turbulence, lower n values, approaching a minimum of 0.5 should be used.



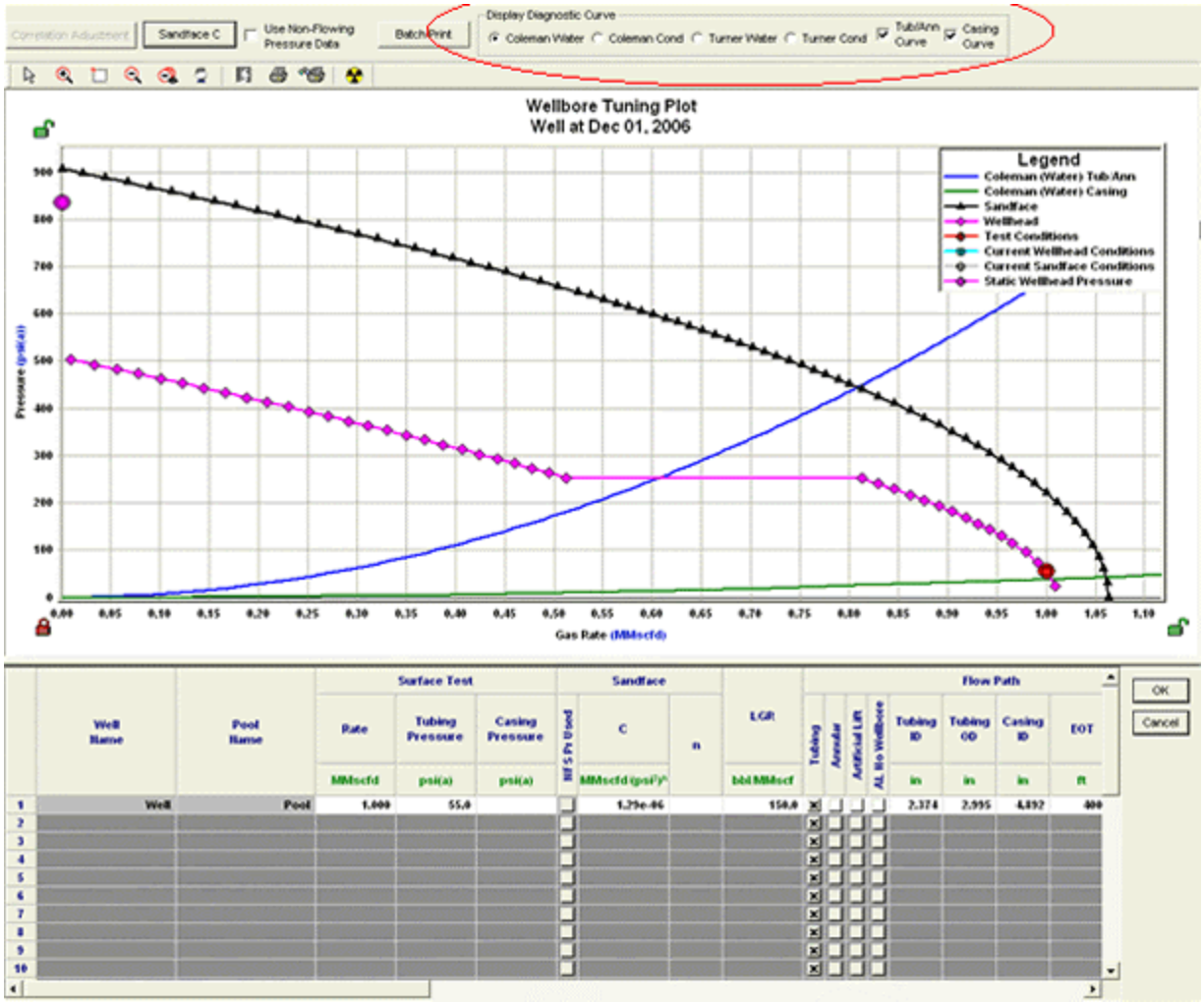
C. Calculate the Sandface C value for the well by clicking the "Sandface C" button (top left corner of the editor).

Scenario 2

The well is not able to lift liquids, and the C-value can be calculated from non-flowing side wellhead conditions

If the flow rate is lower than the flow rate required to lift liquids (this can be determined by the Turner or Coleman liquid lift correlation), liquids will begin to accumulate within the wellbore and create an additional pressure drop that will restrict the well performance, or at times even shut the well in. The Turner or Coleman diagnostic plots, which can be toggled to display in the upper left corner of the Tuning editor, can be used to determine at what rate a well will no longer be able to lift liquids. The curves display the minimum gas rate, as predicted by either the Turner or Coleman liquid lift correlation, whereby liquids would be carried up the wellbore. Using the previous scenario as an

example, at the wellhead pressure of 55 psi, we need ~0.25 MMscfd or more of gas flow to lift liquids in the tubing portion of the wellbore. Note that curves for both the tubing / annulus segment and the casing segment of the wellbore are displayed.

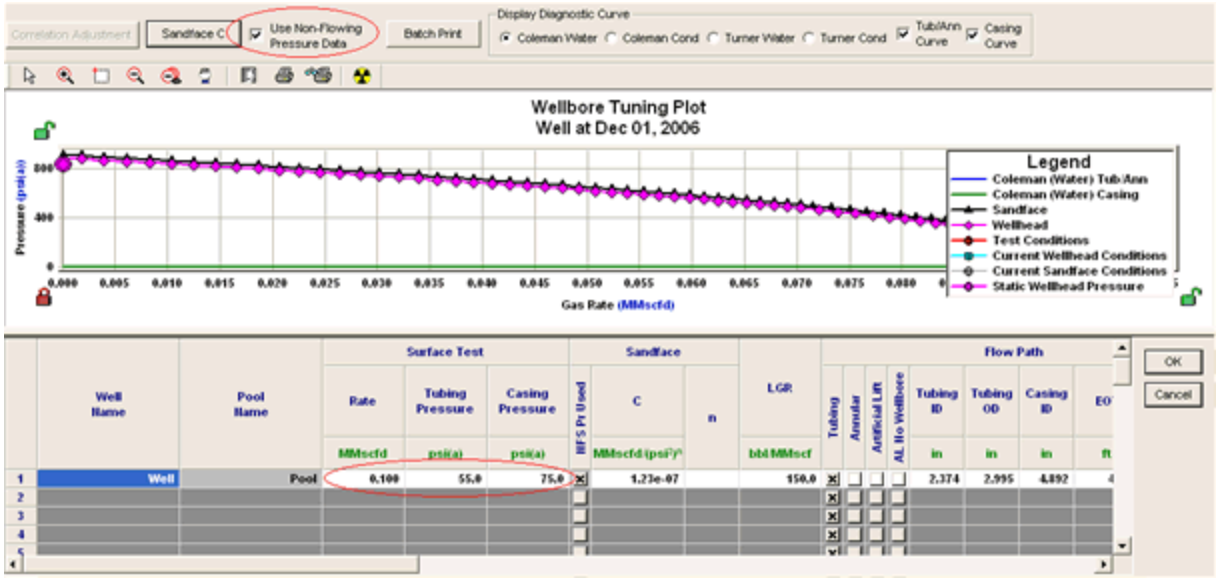


If the flow rate is less then the critical rate, using flowing pressure data to calculate the Sandface deliverability will not be feasible, as the actual flowing pressures will be skewed by the existence of the liquid column in the wellbore.

In such scenarios, if there is no packer downhole, the non-flowing side surface pressure can be used to estimate the bottomhole pressure.

A. Select "Use Non-Flowing Pressure Data" to the right of the Sandface C button.

B. Enter both the current flowing pressure and the non-flowing pressure, as well as the current flow rate.

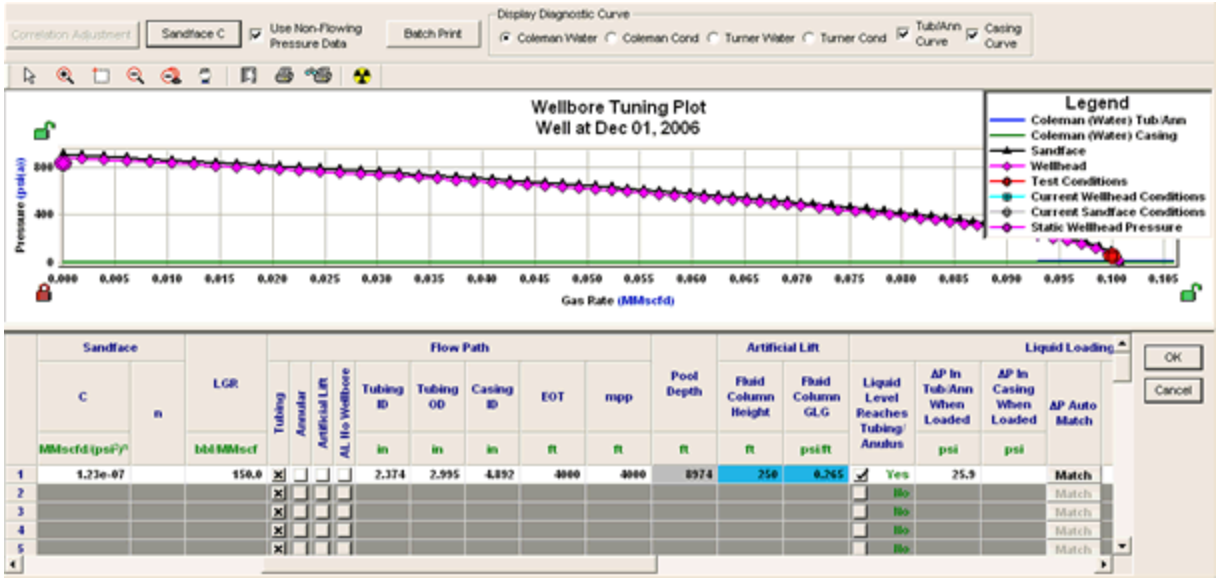


C. Calculate the Sandface C value.

Sandface C will be calculated by extrapolating the non-flowing surface pressure downhole to the end of the tubing. The assumption used is that only a gas gradient exists on the non-flowing side. From the EOT to the MPP, a liquid column exists, and is accounted for with a gradient of 0.265 psi/ft over the length of the casing segment.

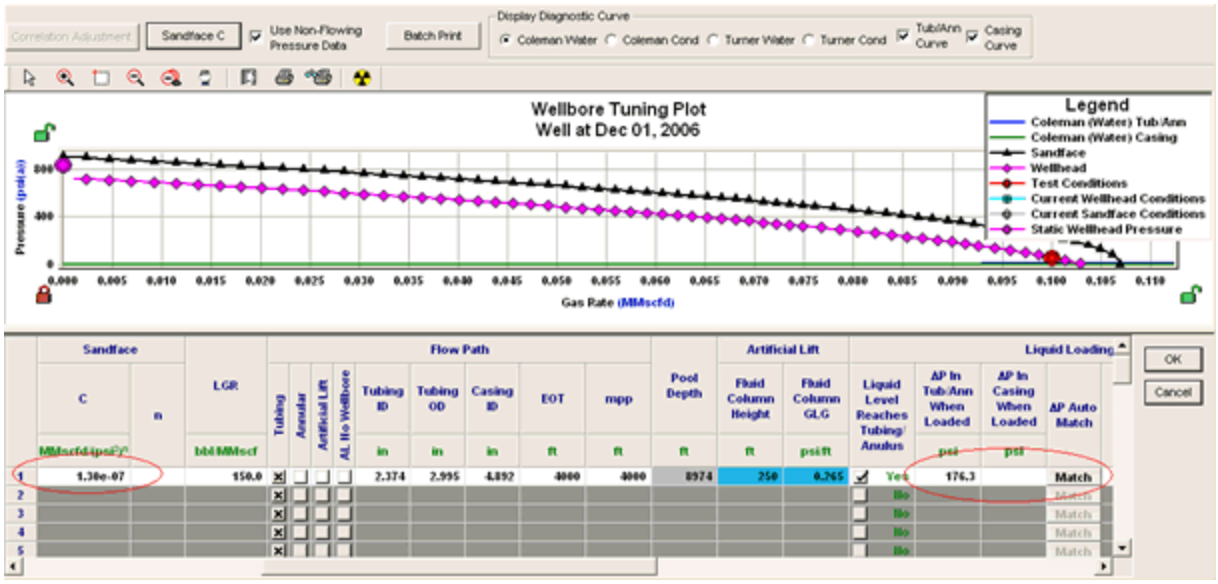
Scenario 3

The C-value is known from a prior flow test, but the well is not able to lift liquids, so the C-value is matched to current flowing wellhead conditions by allowing Piper to adjust the effect of liquids in the wellbore.



A. Manually enter a Sandface C

B. Use the Auto Match to match the flowing side pressure and flow rate (shown on the plot with the red circle) to the Sandface C that was entered. The "ΔP in Tub / Ann When Loaded" will be adjusted to match the pressure drop between the current surface and sandface condition.



For more information about the calculations, see Sandface C calculations.

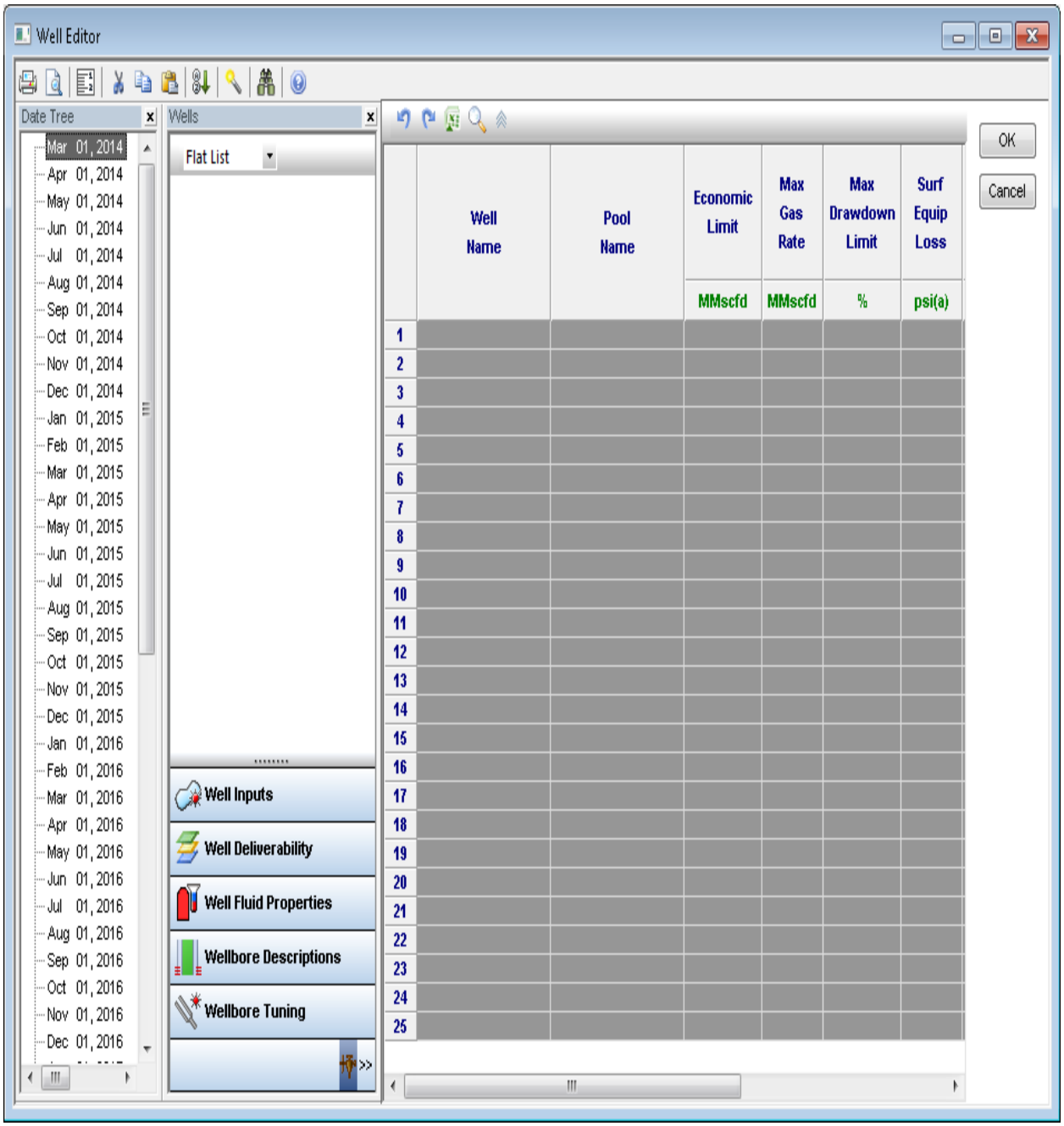
For a more detailed description of modeling and options, see Wellbore Tuning Reference Materials.

Well options

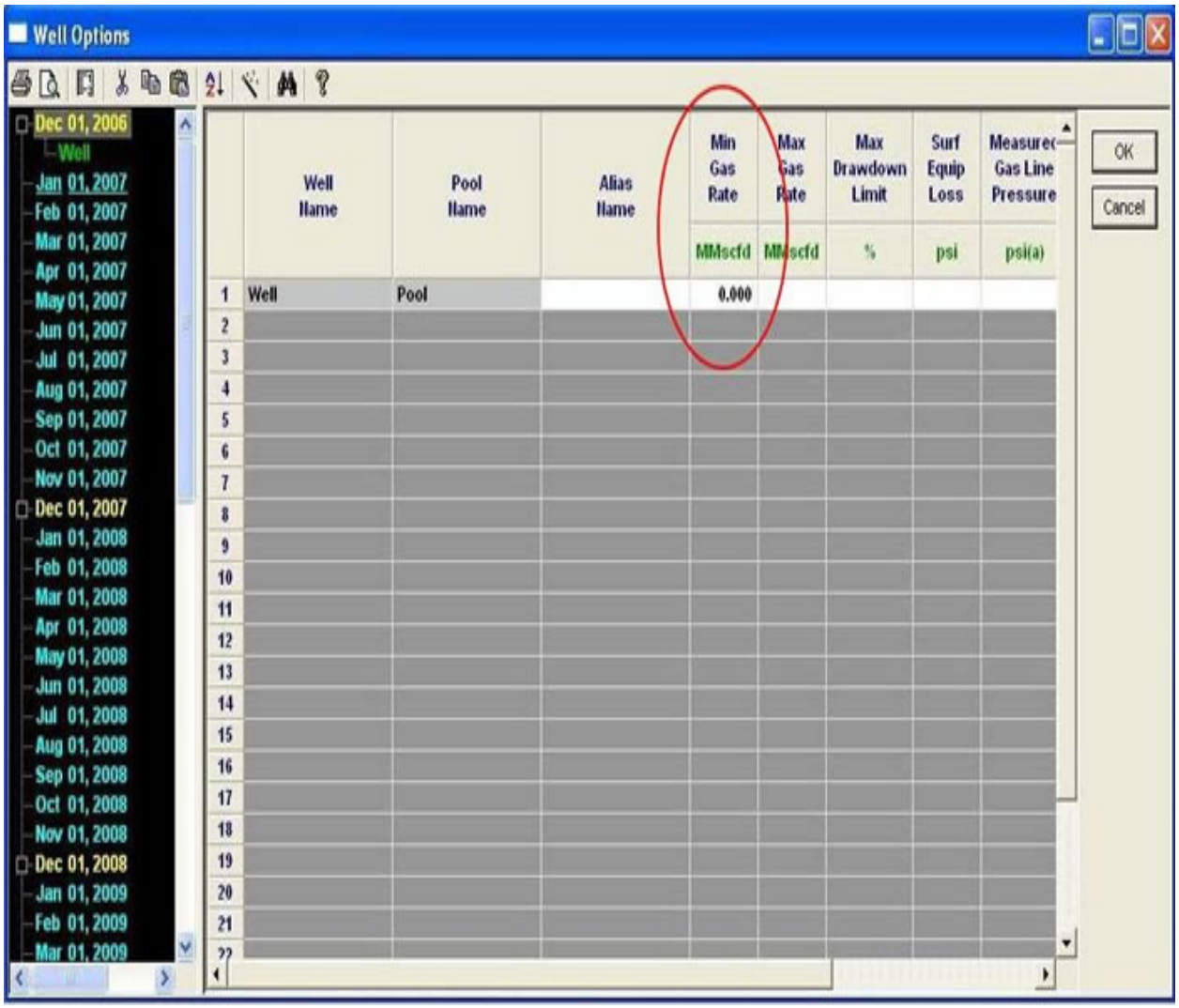
In the Well Options editor, you can apply flow rate restrictions to wells, impose a maximum draw-down limit, or specify surface equipment losses. If measured line pressures are available, you can enter these values in the Measured Gas Line or Measured Water Line Pressure columns.

Note: Data entered in the Measured Gas Line Pressure column is not used for calculation purposes, but it is sometimes useful to display this information either on the map or bubble map dialog box. With this information, you can visualize the difference between field reported and model calculated pressures.

Data entered in the Measured Water Line Pressure column is not used for calculation purposes either. This feature is available to monitor the difference between gas line pressures and water line operating pressures on an on-going basis.



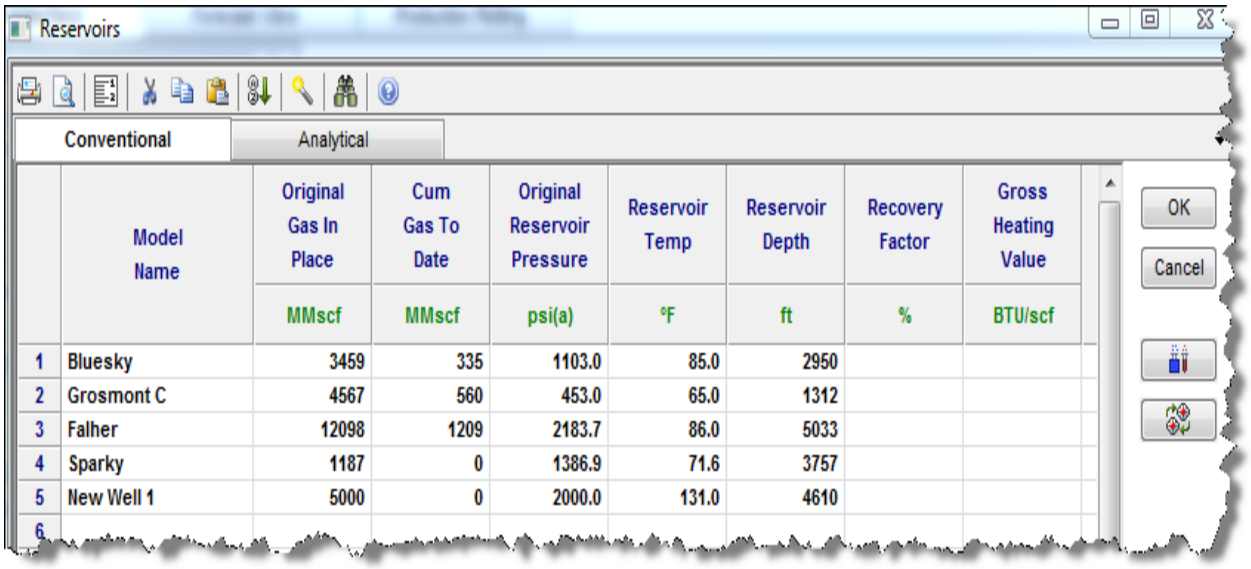
If your well shuts in and you cannot get it to produce again, even after reducing the line pressure upstream of the well (to the point where it should produce), try setting the Min Gas Rate to zero in the Well Options editor. Wells that have no production return to production when there are reductions to the line pressure downstream of the well, etc.



Reservoirs editor

With this editor, you can define gas reservoir properties. Although the majority of modeling work typically involves gas reservoirs undergoing volumetric depletion, other drive mechanisms can be modeled such as:

- Pressure support from connected reservoirs
- Pressure support from aquifers
- Over pressured reservoirs



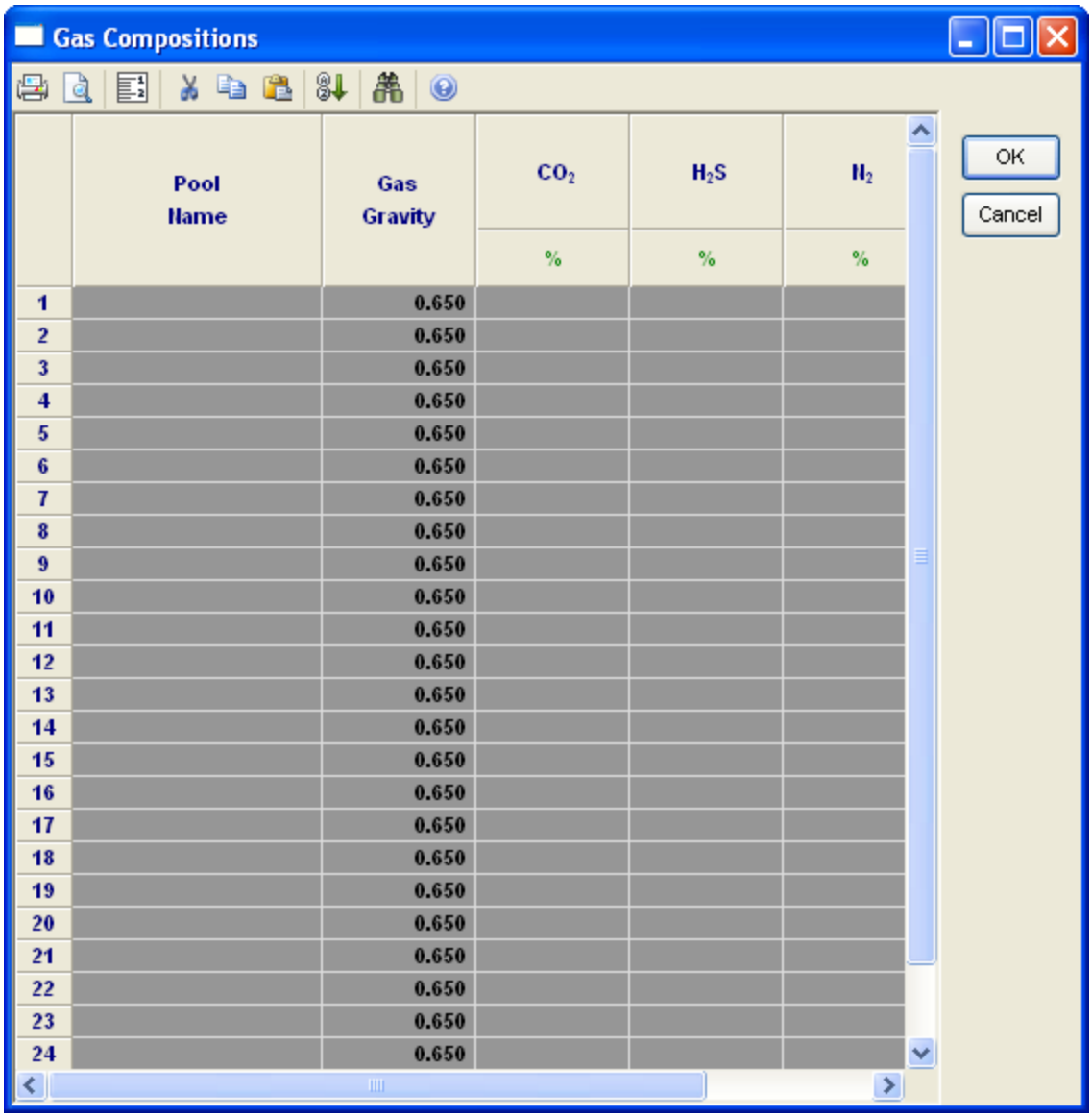
	Model Name	Original Gas In Place	Cum Gas To Date	Original Reservoir Pressure	Reservoir Temp	Reservoir Depth	Recovery Factor	Gross Heating Value
		MMscf	MMscf	psi(a)	°F	ft	%	BTU/scf
1	Bluesky	3459	335	1103.0	85.0	2950		
2	Grosmont C	4567	560	453.0	65.0	1312		
3	Falher	12098	1209	2183.7	86.0	5033		
4	Sparky	1187	0	1386.9	71.6	3757		
5	New Well 1	5000	0	2000.0	131.0	4610		
6								

For these more advanced modeling scenarios, data is entered into the Connected Reservoir / Water Drive editor .

For a more detailed description of the reservoir types available, see Reservoirs .

Reservoir Gas Compositions editor

This editor can be accessed either from within the Reservoirs Editor, or on the main toolbar. With this editor, you can enter the reservoir gas composition. When wells are connected to a reservoir, then you have the option to use the reservoir gas composition for that well from the Well Editor. For more information, see Well Fluid Properties.



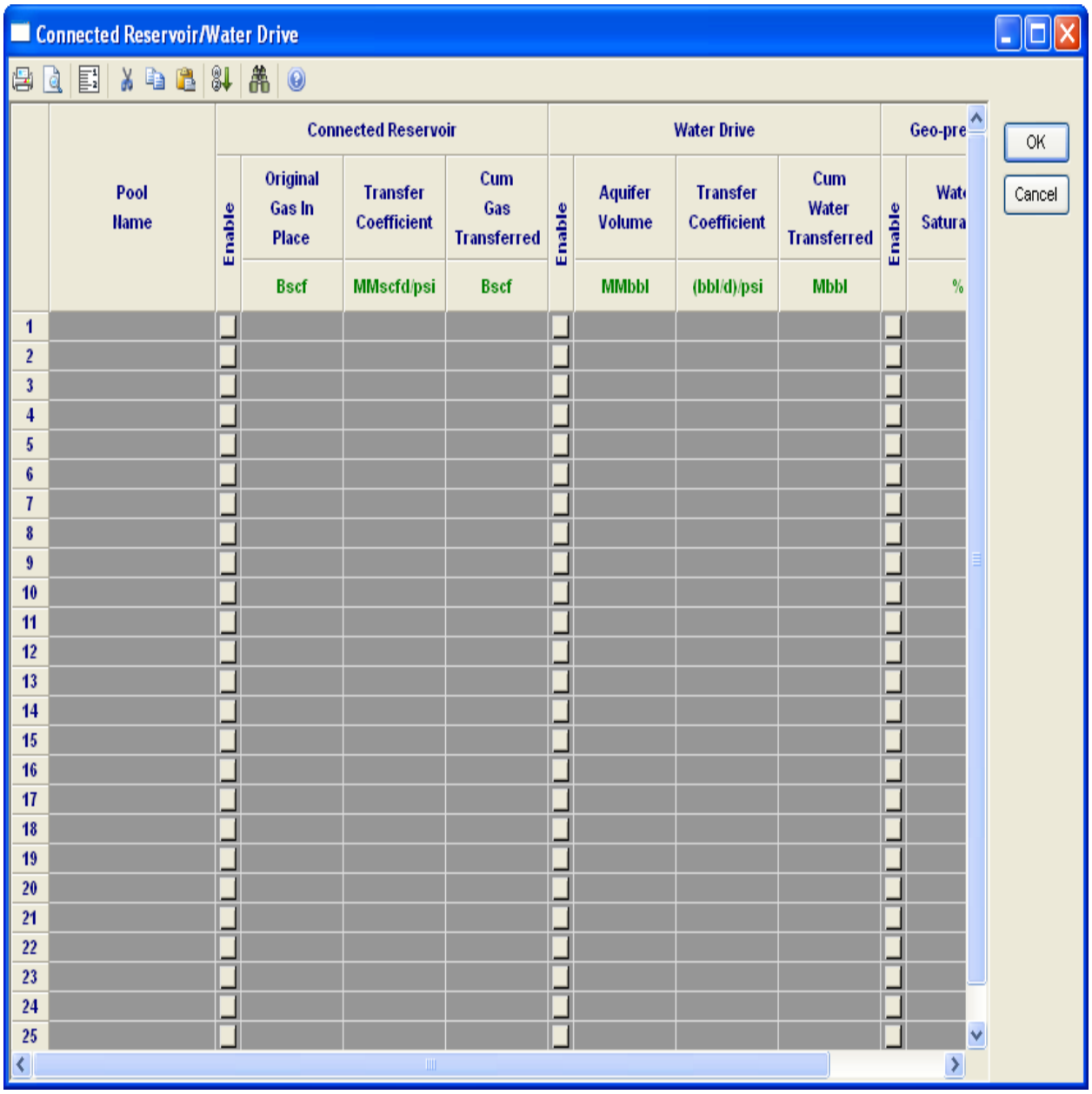
	Pool Name	Gas Gravity	CO_2 %	H_2S %	N_2 %
1		0.650			
2		0.650			
3		0.650			
4		0.650			
5		0.650			
6		0.650			
7		0.650			
8		0.650			
9		0.650			
10		0.650			
11		0.650			
12		0.650			
13		0.650			
14		0.650			
15		0.650			
16		0.650			
17		0.650			
18		0.650			
19		0.650			
20		0.650			
21		0.650			
22		0.650			
23		0.650			
24		0.650			

Connected Reservoir / Water Drive editor

The connected reservoir / water drive model extends the capabilities of the reservoir editor to include non-pressure depleting reservoirs. Reservoir types defined in this editor are:

- Connected reservoirs
- Water drive reservoirs
- Geo-pressured reservoirs

The Connected Reservoir / Water Drive editor is shown below.



The connected reservoir model (associated tight gas reservoir volumes in intimate contact with the main reservoir gas-in-place) is based on the method developed by David Payne, "Material Balance Calculations in Tight Gas Reservoirs: The Pitfalls of P/Z Plots and a More Accurate Technique", 1996, SPE 36702.

The water drive model is a steady-state solution for water drive reservoirs based on the method put forward by Fetkovich.

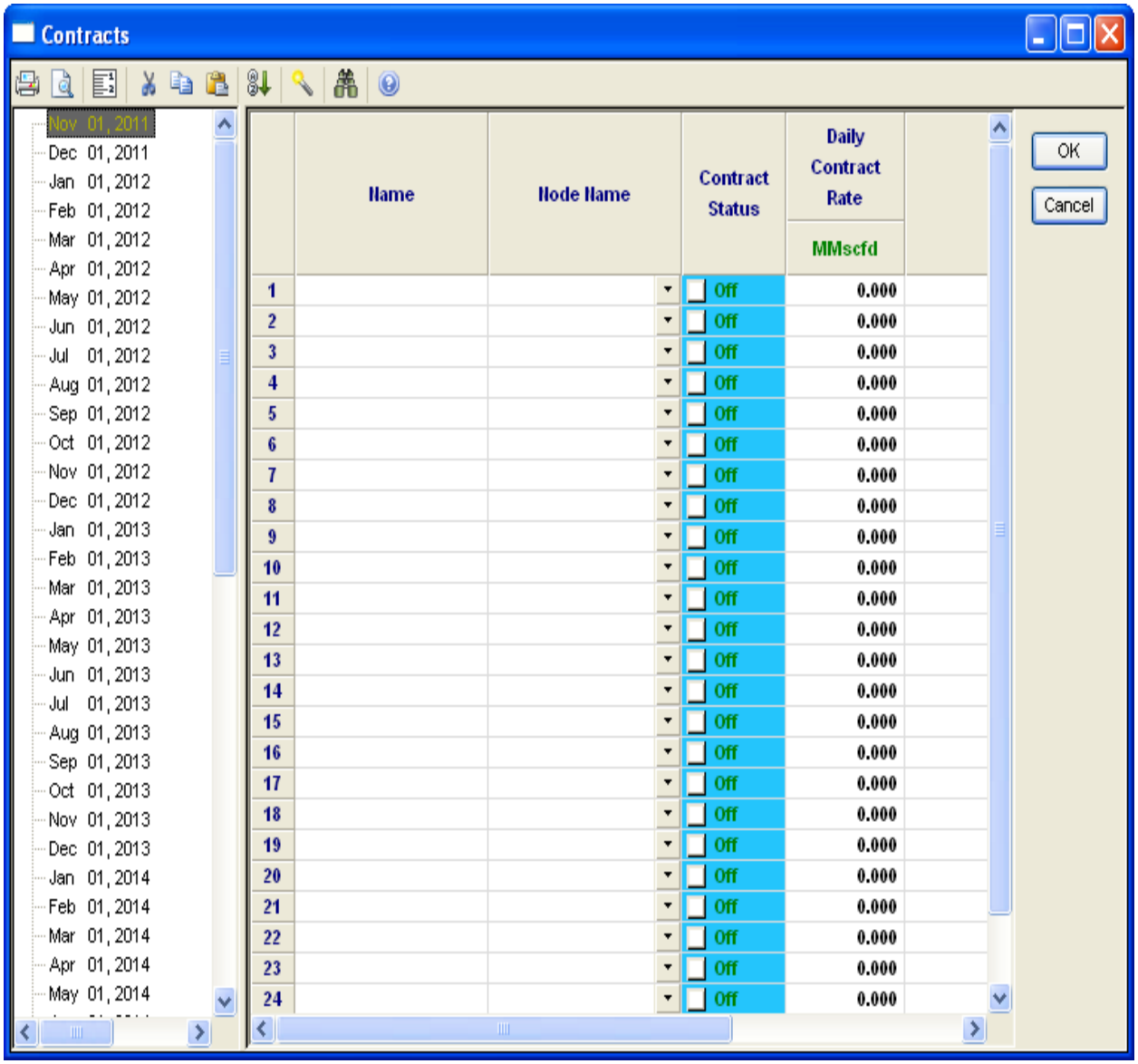
The geo-pressure reservoir model accounts for the compressibility effects of connate water and rock.

The connected reservoir / water drive model is designed to model the pressure support of an underlying aquifer using the method derived by Fetkovich. The connected / water drive data inputs work together with inputs from the associated reservoir names in the Reservoirs editor. Guessing for input parameters is not recommended.

For a more detailed description of the reservoir types available, seeReservoirs .

Contracts editor

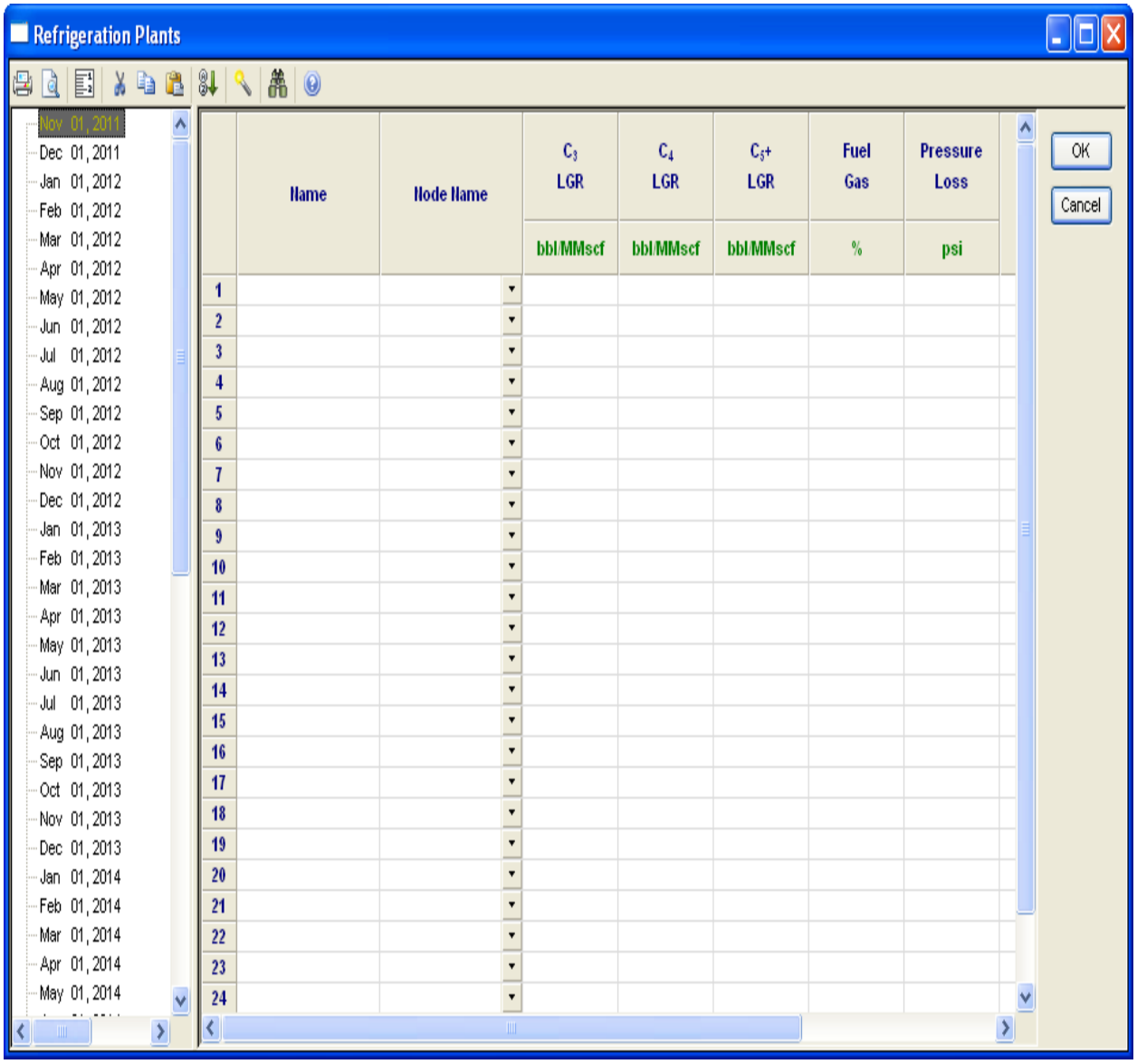
Contracts are used to restrict flow through a node below a value, which you specify, the contract volume. The contract facility acts as a choke restricting production to a specified volume. Once the field is no longer able to meet the contract requirement, the choke is removed.



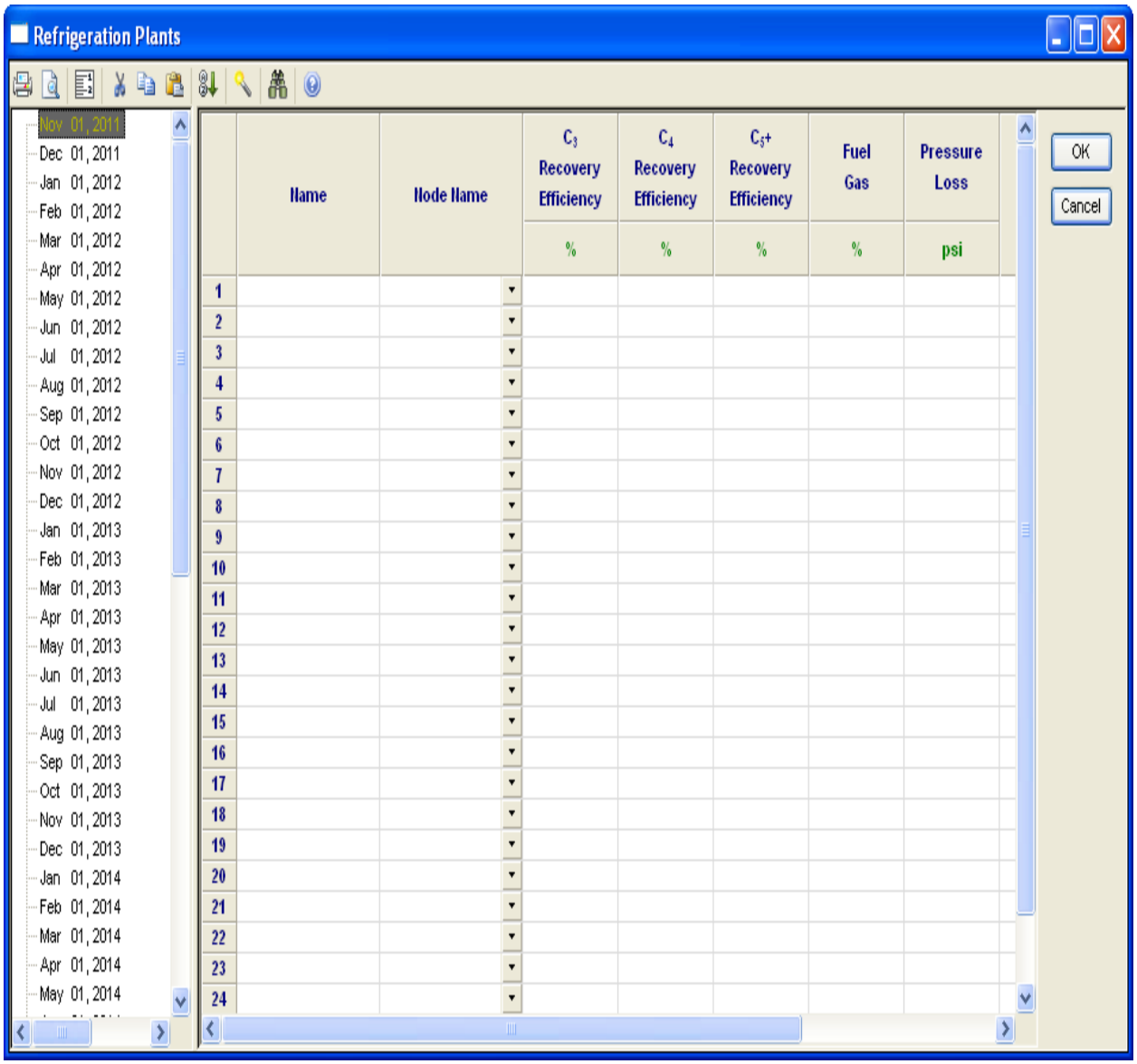
Refrigeration Plants editor

Refrigeration plants are used to remove natural gas liquids (NGLs) from the gas stream entering a node. The amount of liquids removed can be specified in one of two ways:

1. **Liquid Yields** - you specify the liquid yield (bbls/mmcfd) for a specific NGL component. This option is available when a simplified gas analysis is used.



2. **Recovery Efficiency** - you can specify the fraction of each component that is removed from the raw gas stream. This option is available when a detailed gas analysis is used.

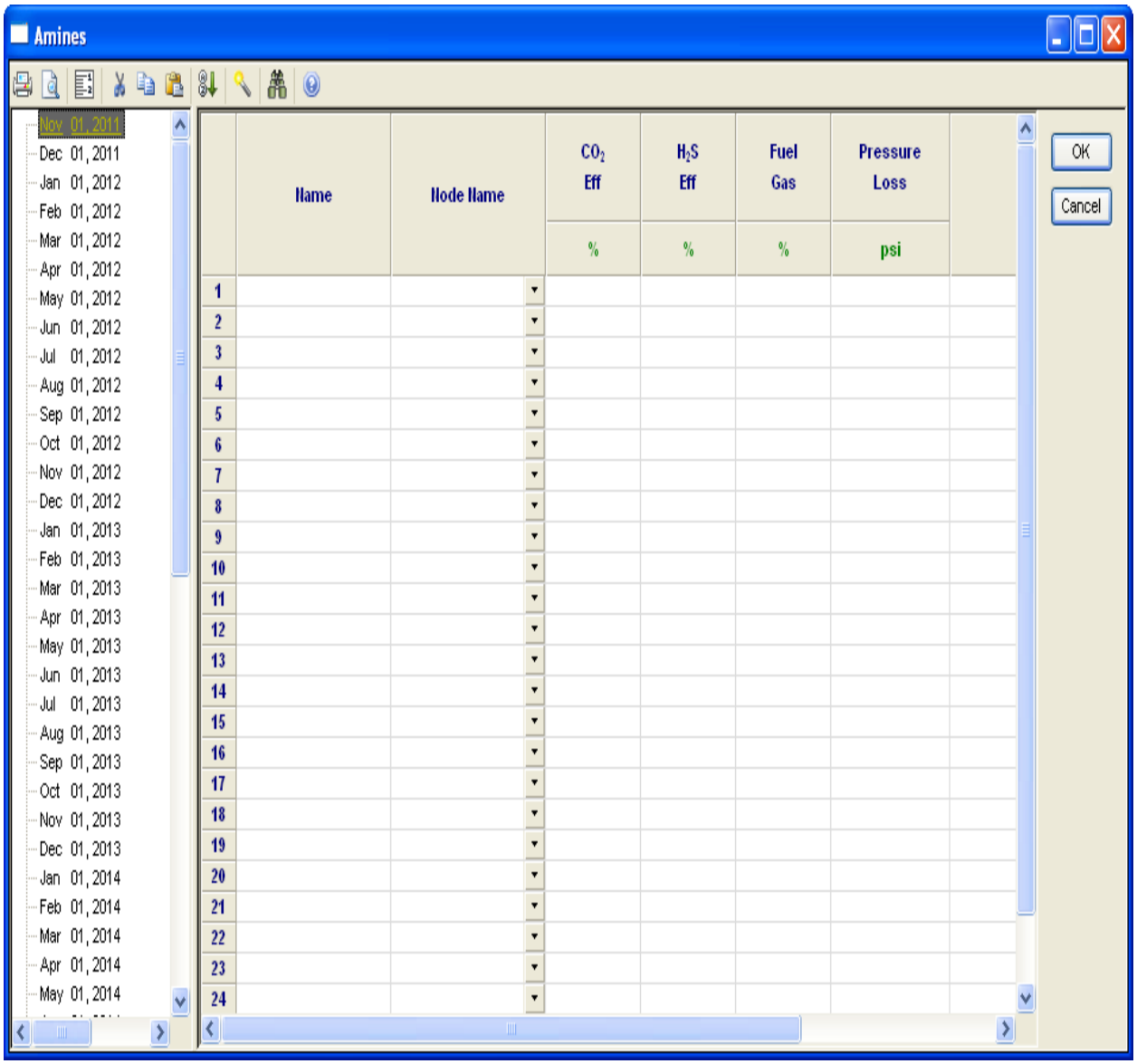


With the refrigeration editor, you can also specify fuel gas requirements expressed as a percentage of throughput volume, and pressure losses across the facility, if applicable.

For a more detailed description of refrigeration modeling and options, see Refrigeration .

Amines editor

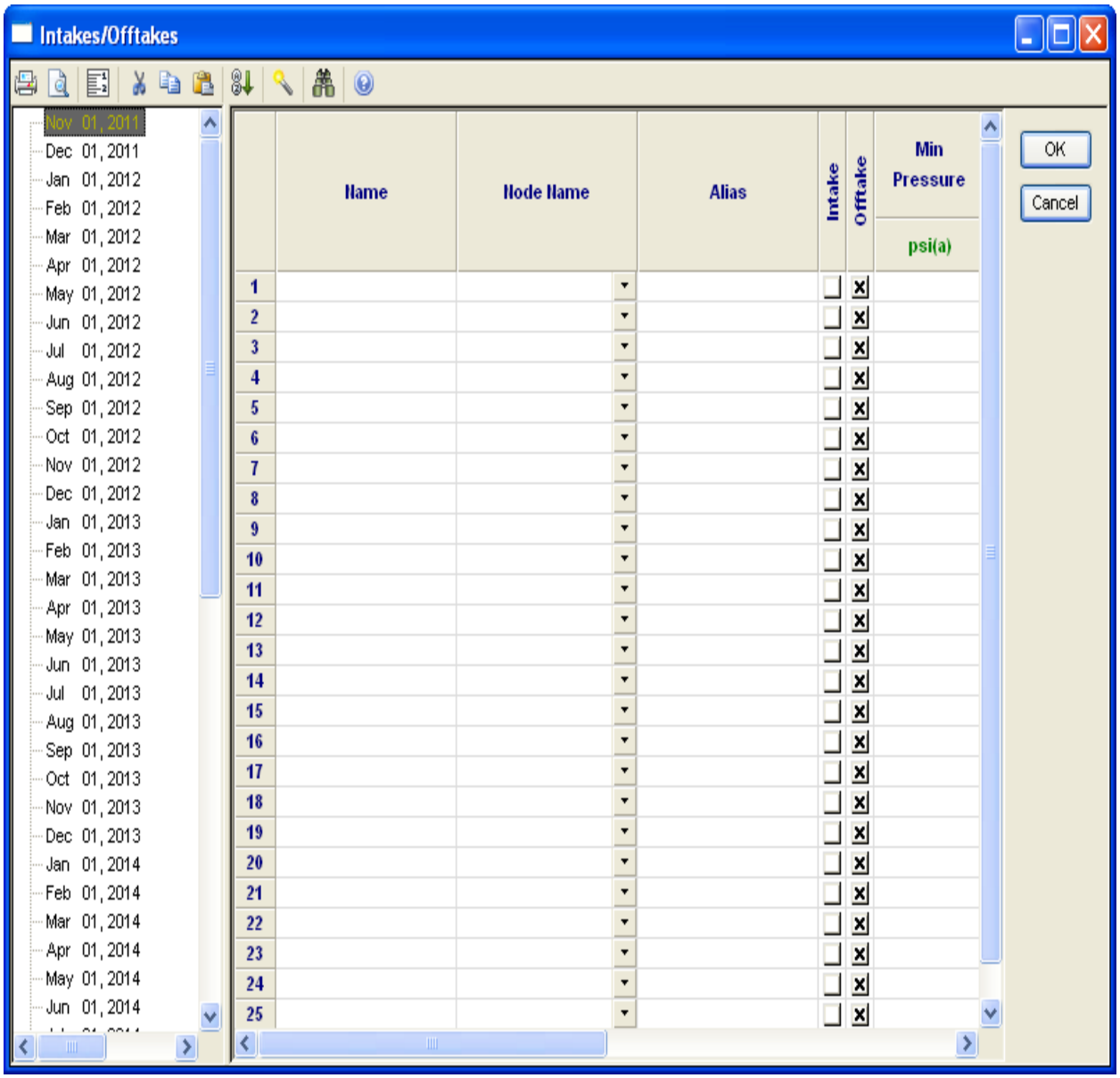
Amine plants are used to remove acid gas components from a raw gas stream. In this editor, you can specify the percentage of acid gas components to remove, fuel gas, and pressure losses through the facility.



For a more detailed description of amine modeling and options, see Amineseparators.

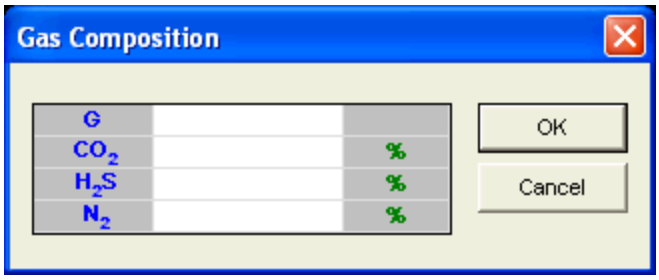
Intakes / Offtakes editor

With Piper, you can incorporate gas volume additions from facilities other than wells (intakes), and withdrawals to multiple delivery and/or sales points (offtakes).



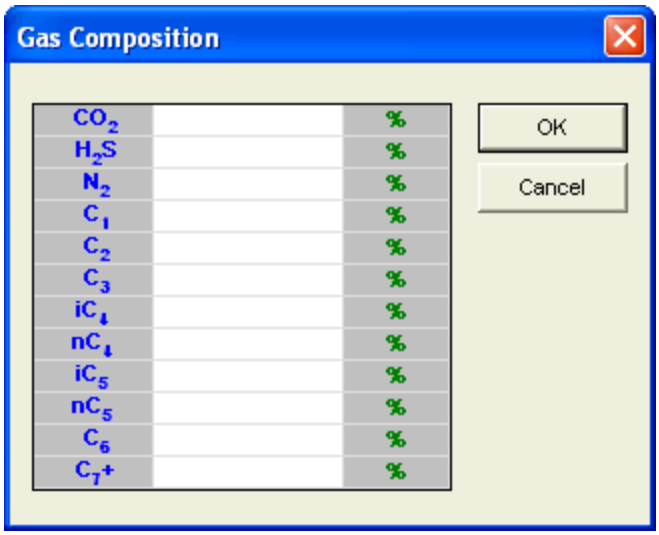
With intake facilities, you can enter a fixed volume of gas into a system. You can define the composition of the injected gas in the Gas Props column: either a simple or detailed analysis can be selected.

Simple analysis



Detailed analysis

To enable this analysis, click the **Forecast Options** menu, and select **Composition Tracking**.

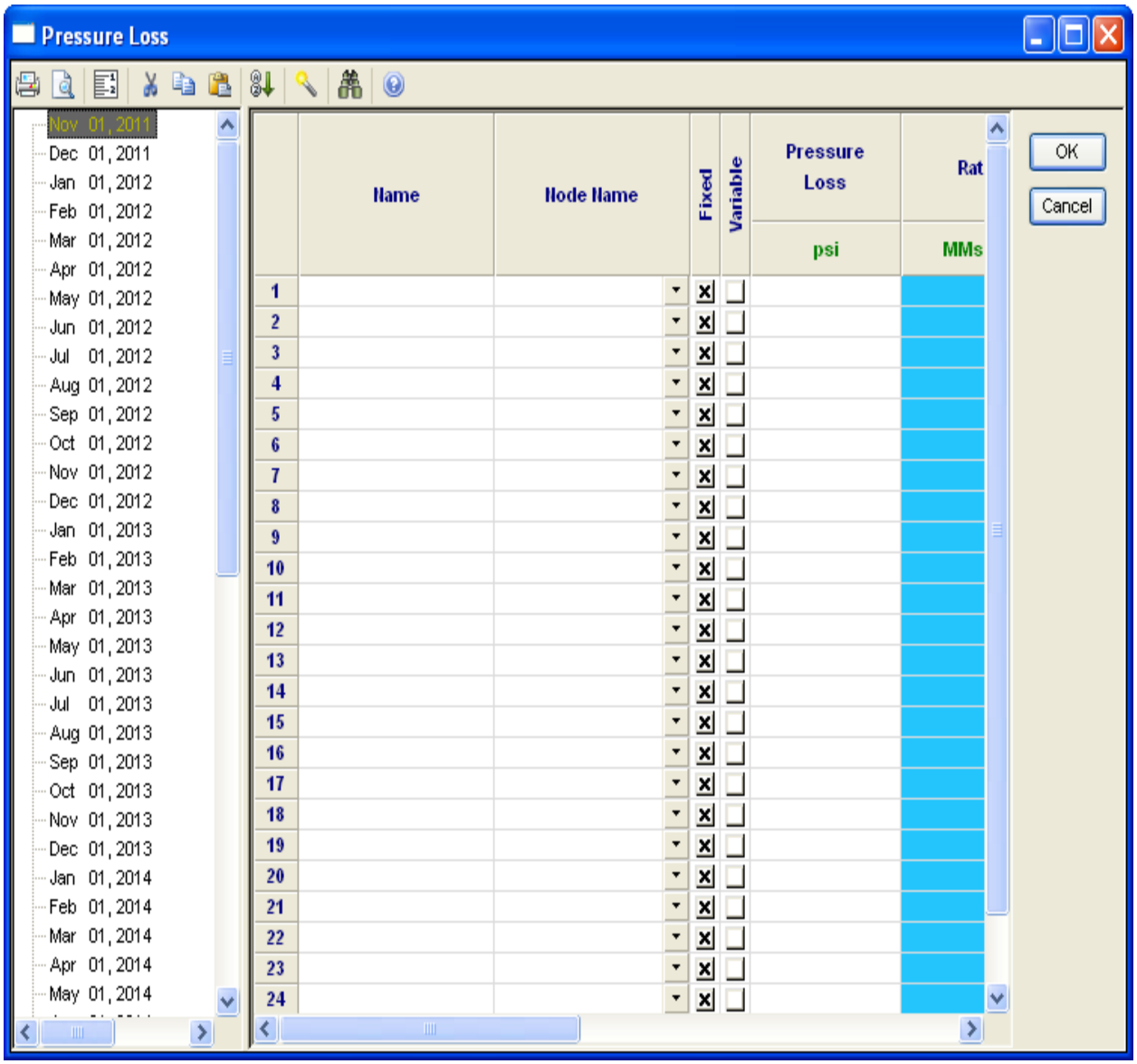


Offtakes provide you with the flexibility to incorporate several delivery points into a single model. An offtake requires a fixed gas rate and a minimum delivery pressure to be specified. If the specified rate cannot be maintained, at or above the minimum delivery pressure, the offtake facility is automatically disabled. If the staging option is selected, the offtake facility continues to accept gas, at a reduced rate, while maintaining the specified minimum delivery pressure.

For a more detailed description of modeling and options, see Intakes and Offtakes.

Pressure Loss editor

With Piper, you can assign additional pressure losses to any point in a gathering system.



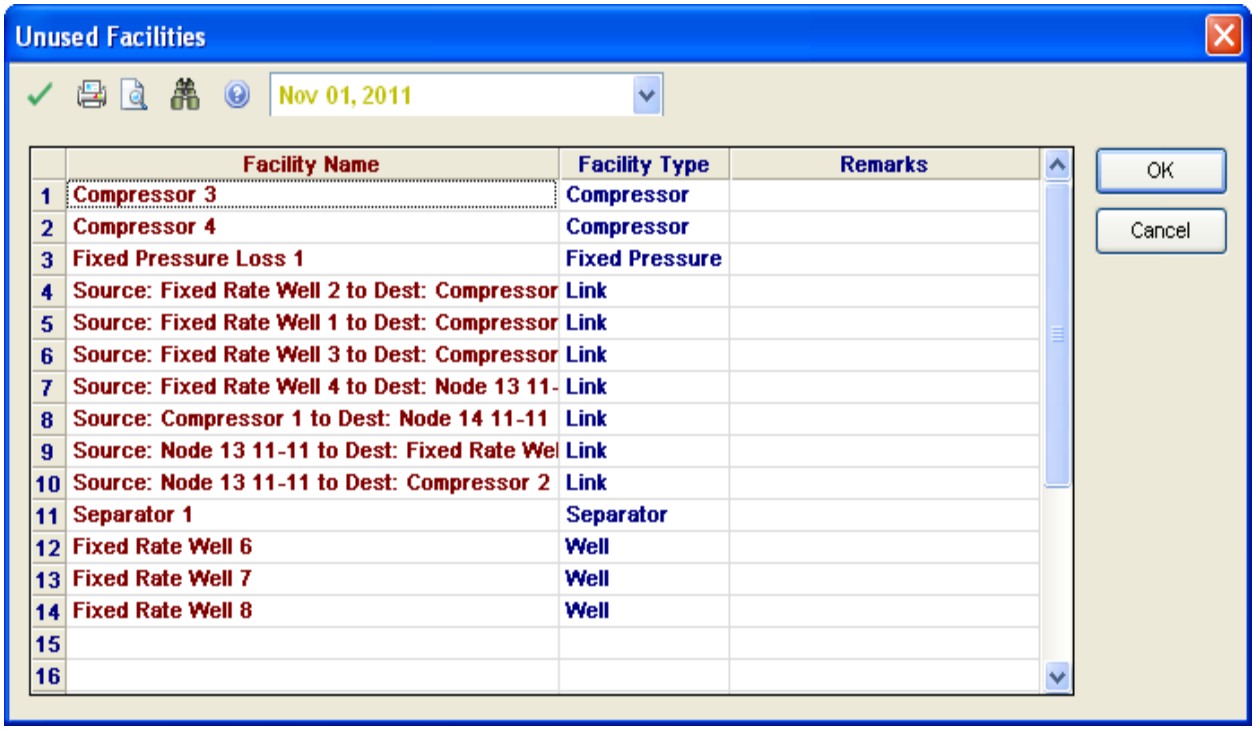
Once a location has been defined, you can choose either a fixed or variable pressure loss. Fixed pressure losses stay constant through time and require the pressure loss to be specified. Variable pressure losses change in accordance with production rates, and you are required to enter the pressure loss, gas rate, and outlet pressure. These parameters are entered for the initial month the variable pressure loss is introduced.

For a more detailed description of modeling and options, see Pressure Losses.



Unused Facilities

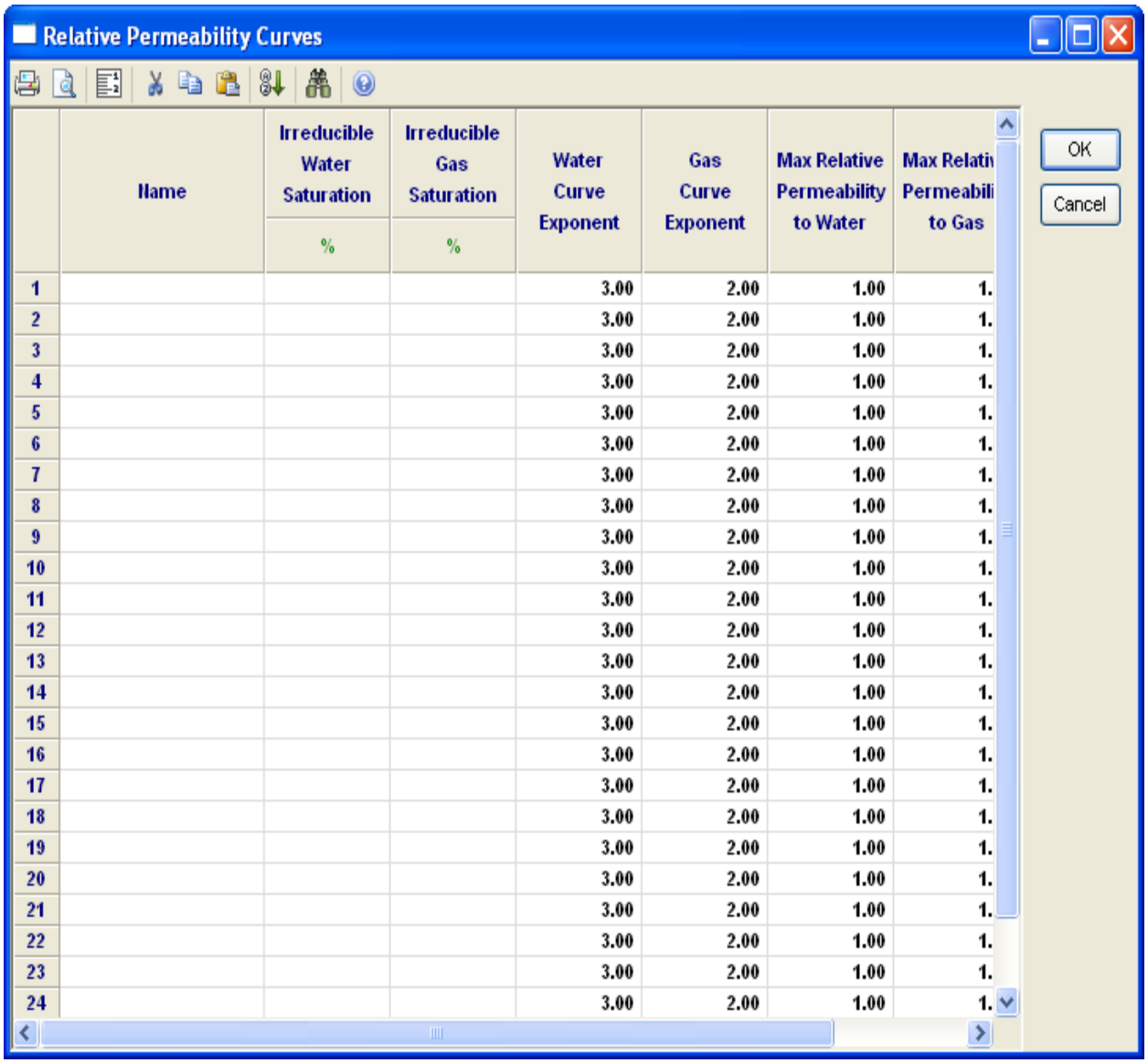
Unused facilities are displayed in this dialog box. If there are a lot of entries in this dialog box, it is a good idea to check the system links. When equipment is disconnected, other linked items can also become disconnected.



	Facility Name	Facility Type	Remarks
1	Compressor 3	Compressor	
2	Compressor 4	Compressor	
3	Fixed Pressure Loss 1	Fixed Pressure	
4	Source: Fixed Rate Well 2 to Dest: Compressor	Link	
5	Source: Fixed Rate Well 1 to Dest: Compressor	Link	
6	Source: Fixed Rate Well 3 to Dest: Compressor	Link	
7	Source: Fixed Rate Well 4 to Dest: Node 13 11-	Link	
8	Source: Compressor 1 to Dest: Node 14 11-11	Link	
9	Source: Node 13 11-11 to Dest: Fixed Rate Wel	Link	
10	Source: Node 13 11-11 to Dest: Compressor 2	Link	
11	Separator 1	Separator	
12	Fixed Rate Well 6	Well	
13	Fixed Rate Well 7	Well	
14	Fixed Rate Well 8	Well	
15			
16			

Relative Permeability Curves editor

To open the Relative Permeability editor, click its icon. This editor is automatically populated with parameters from importing history-matched wells from Harmony Enterprise. Percent irreducible water and gas saturation, water and gas curve exponent, and maximum relative permeability to water and gas are specified in this editor.



	Name	Irreducible Water Saturation %	Irreducible Gas Saturation %	Water Curve Exponent	Gas Curve Exponent	Max Relative Permeability to Water	Max Relati Permeabili to Gas
1				3.00	2.00	1.00	1.
2				3.00	2.00	1.00	1.
3				3.00	2.00	1.00	1.
4				3.00	2.00	1.00	1.
5				3.00	2.00	1.00	1.
6				3.00	2.00	1.00	1.
7				3.00	2.00	1.00	1.
8				3.00	2.00	1.00	1.
9				3.00	2.00	1.00	1.
10				3.00	2.00	1.00	1.
11				3.00	2.00	1.00	1.
12				3.00	2.00	1.00	1.
13				3.00	2.00	1.00	1.
14				3.00	2.00	1.00	1.
15				3.00	2.00	1.00	1.
16				3.00	2.00	1.00	1.
17				3.00	2.00	1.00	1.
18				3.00	2.00	1.00	1.
19				3.00	2.00	1.00	1.
20				3.00	2.00	1.00	1.
21				3.00	2.00	1.00	1.
22				3.00	2.00	1.00	1.
23				3.00	2.00	1.00	1.
24				3.00	2.00	1.00	1.

Default dialog box editor

The Default dialog box editor sets the default values for many of the properties and units used by Piper.

Erosional Velocity Constant	100	
Max Pipe Seg Division	20	
Max Wellbore Seg Division	20	
EOS Max Pipe Seg Division	20	
EOS Max Wellbore Seg Division	10	
Load Factor	100.0	%
Gasified Liquid Column Gradient	0.265	psi/ft
Node Deliverability Pressure Increment	5	
Default Units For New Files	(•) Metric ( ) Field	
Default Pipe Units	( ) miles/km (•) ft/m	
Default Pump Units for new files	(•) psi/kpa ( ) Head(ft)/Head(m)	
Default Loop Link Selection Method	( ) Piper Selects Loop Link (•) User Selects Loop Link	
Analytical Model Gap Production	(•) Constant Pressure Flow ( ) Well is Shut-in	
Auto Save Defaults	Change Settings	
Simple Composition		
Gas Gravity	0.65	
CO_2		%
H_2S		%
N_2		%
C_{7+} Detail Composition		
CO_2	0.0	%
H_2S	0.0	%
N_2	0.0	%
C_1	92.0	%
C_2	2.0	%
C_3	2.0	%
iC_4	1.0	%
nC_4	1.2	%
iC_5	0.8	%
nC_5	1.0	%
C_6	0.0	%
C_{7+} Detail Composition	0.0	%
Total	100.0	%
C_{7+} MW	150.000000	
C_{7+} γ	0.800000	
CBM Reservoir		
Gas Gravity	0.570000	
CO_2		%
H_2S		%
N_2		%
Oil Gravity	50.0	°API
Water Gravity	1	
Water Salinity	0	ppm
Critical Velocity Correlation	(•) Turner Water ( ) Turner Condensate	
Default hemisphere for UTM Values	(•) North ( ) South	
Temperature Model Defaults		
Default well site line Temperature	40	°F
Default surrounding temperature (T_∞)	40	°F
Default Heat Transfer Coefficient	0.150	BTU/(ft ^{2}hr°F)
Units for Standard Conditions	(•) Metric ( ) Field	
Metric Std Conditions		
Temperature	15	°C
Pressure	101	kPa(a)
Field Std Conditions		
Temperature	60	°F
Pressure	14.7	psi(a)

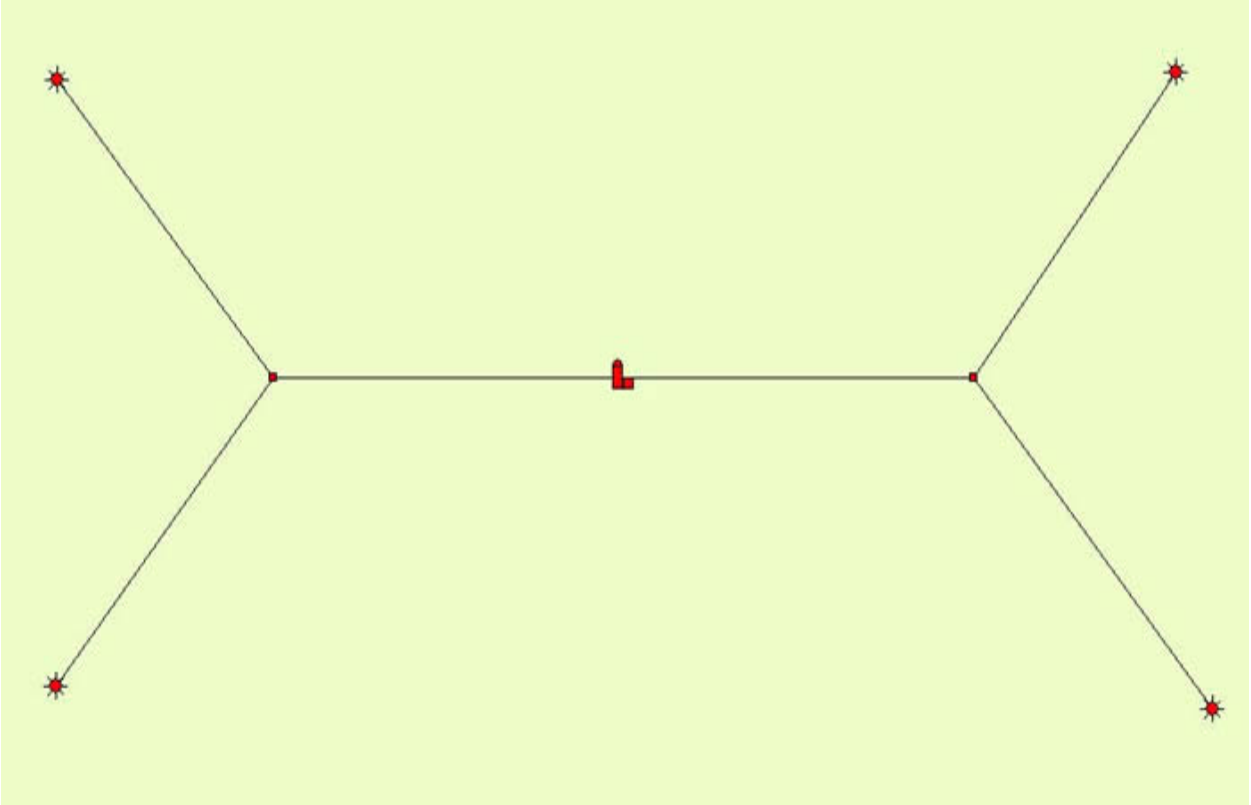
For information on these fields, see defaults.

Diagnostic tools

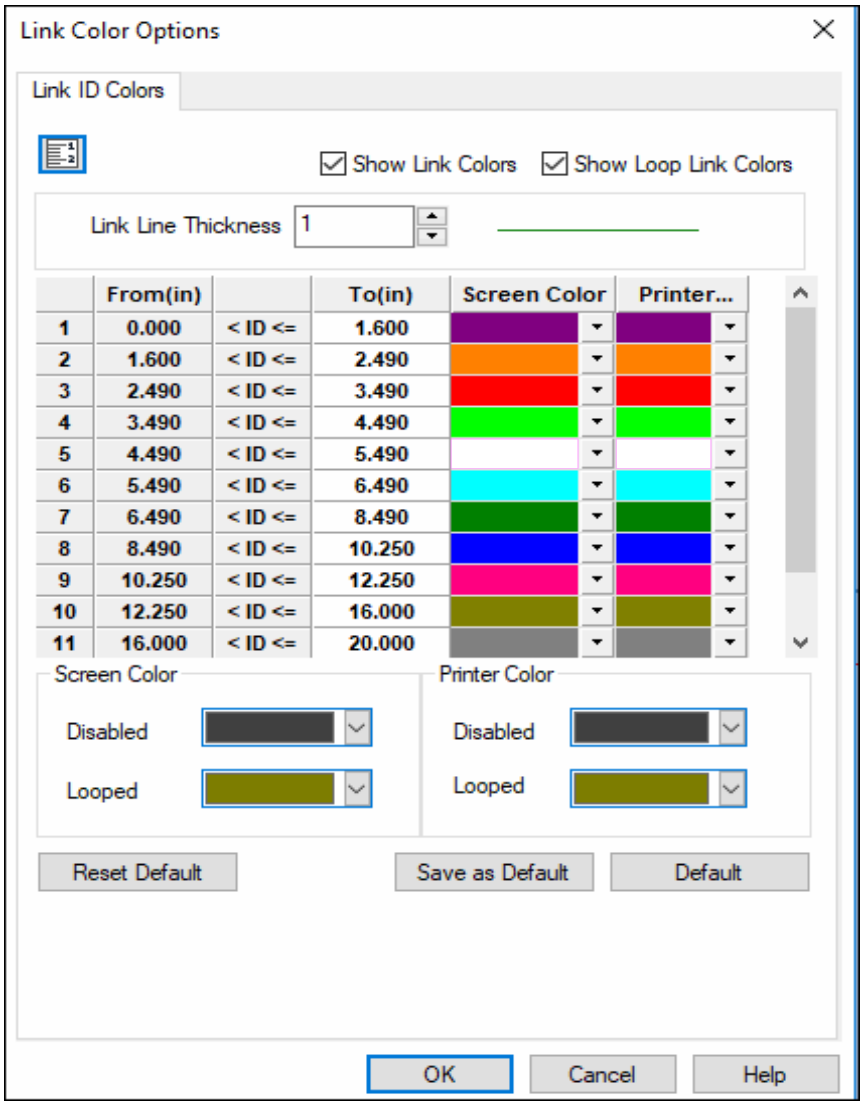
Diagnostic tools are described below.

Using the map

This screen provides a view of the entire gathering system.



Pipeline IDs can be color-coded and the default settings adjusted, by clicking the selecting **Properties** menu and selecting **Link Colors**.:

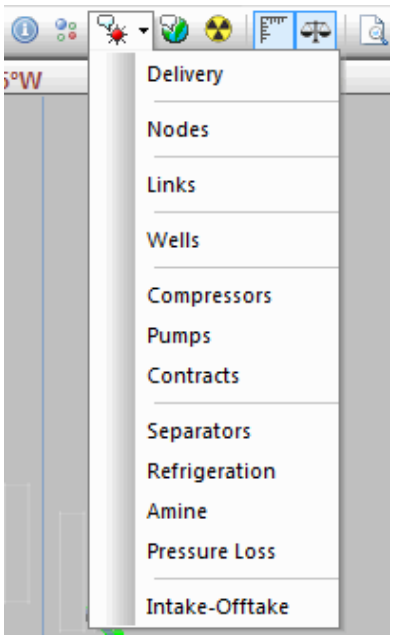


Click the **Show Link Colors** option to toggle pipeline colors on and off.

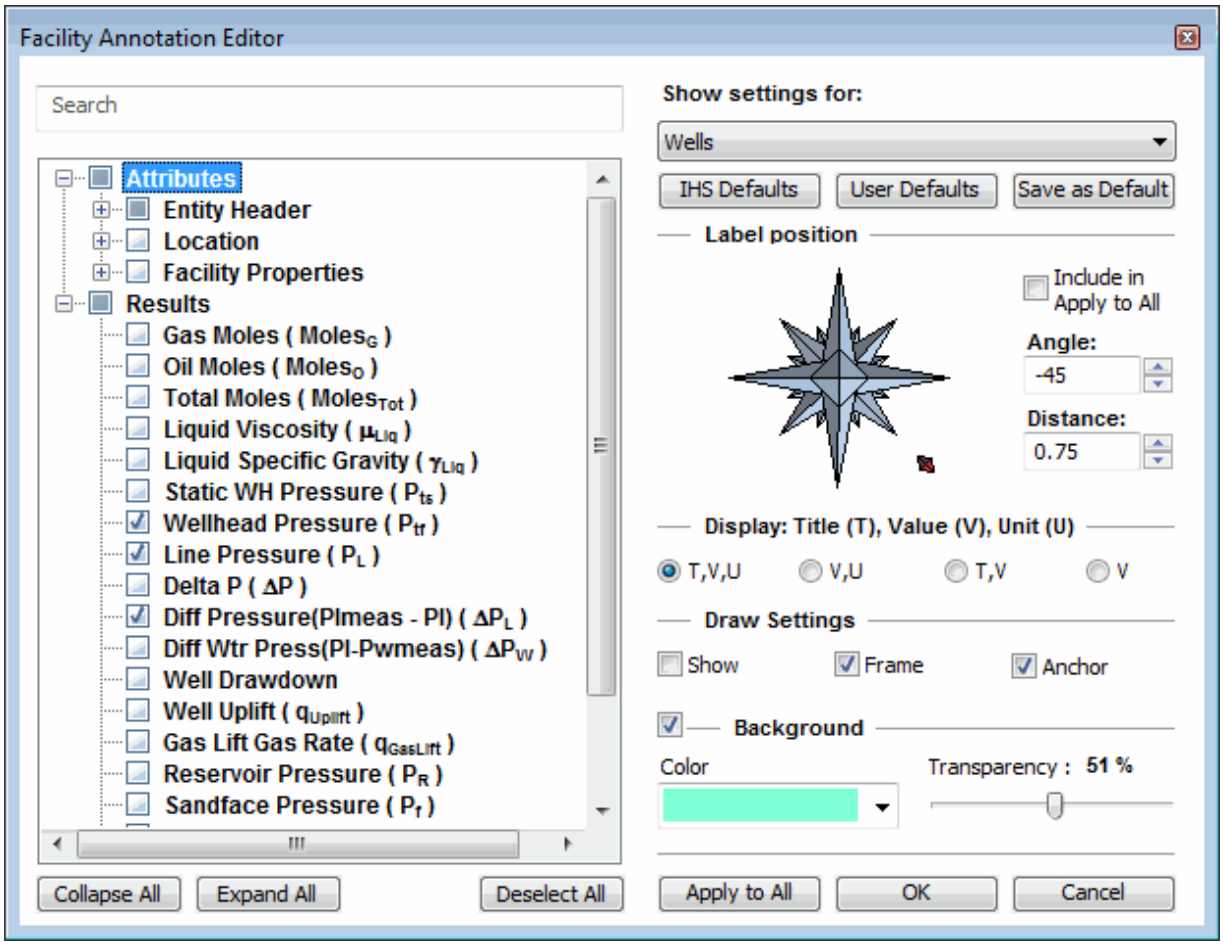
Annotations

Facility annotations

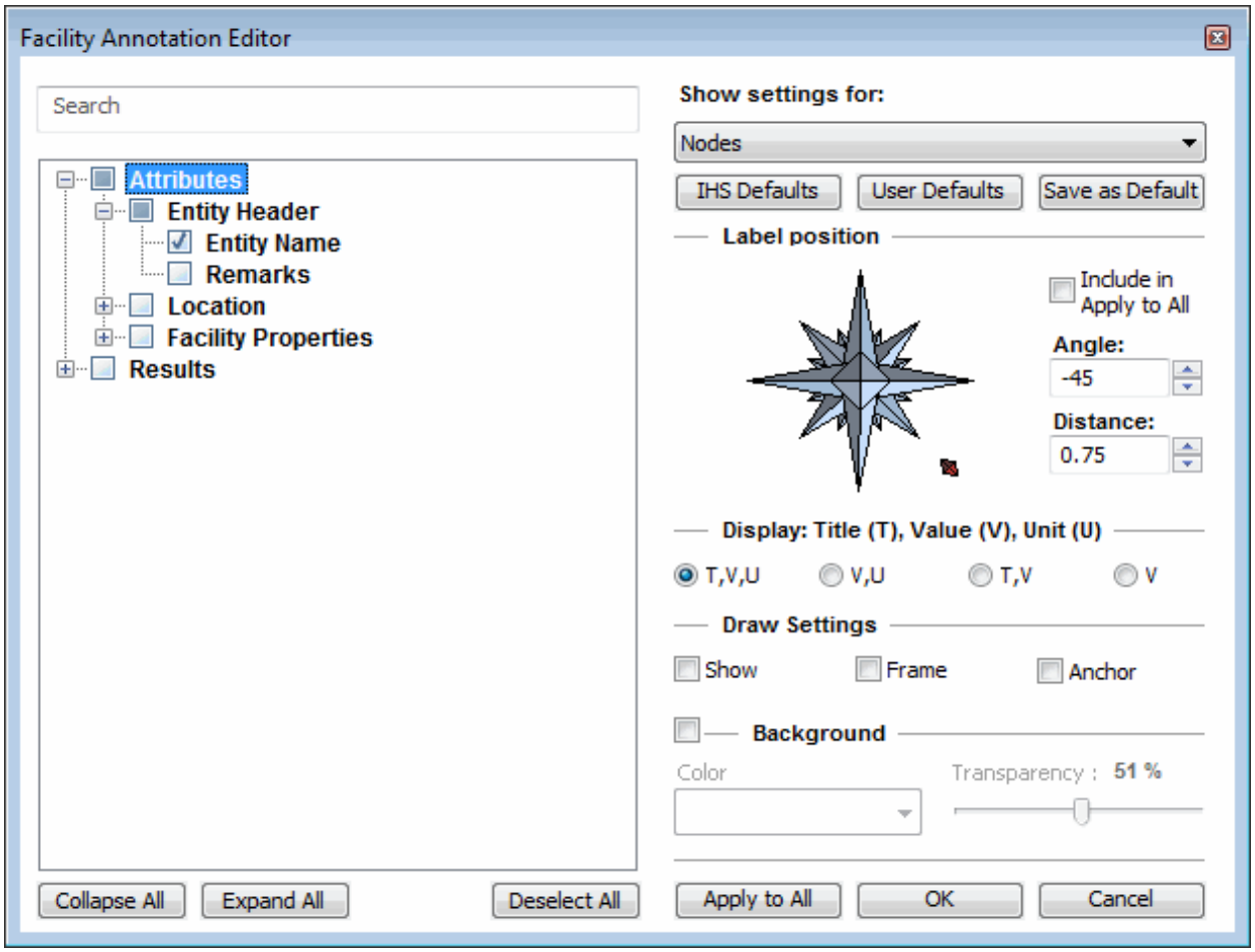
If facility information is needed, annotations are a useful tool. To adjust the display options of facilities in the gathering system map, select the Annotation drop menu in the GIS toolbar.



Each facility type has various information that can be displayed. The left-side of the Facility Annotations Editor, contains a list of properties specialized for the facility type that can be displayed in the map. The right-side has visual properties for the annotations. By default, all annotations are turned off making it easier to create and modify models. Custom defaults can be saved if you prefer by clicking the **Save as Default** button.

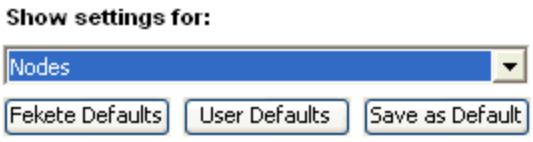


This dialog box controls all annotations for the specific facility type; it does not affect the other facility types.



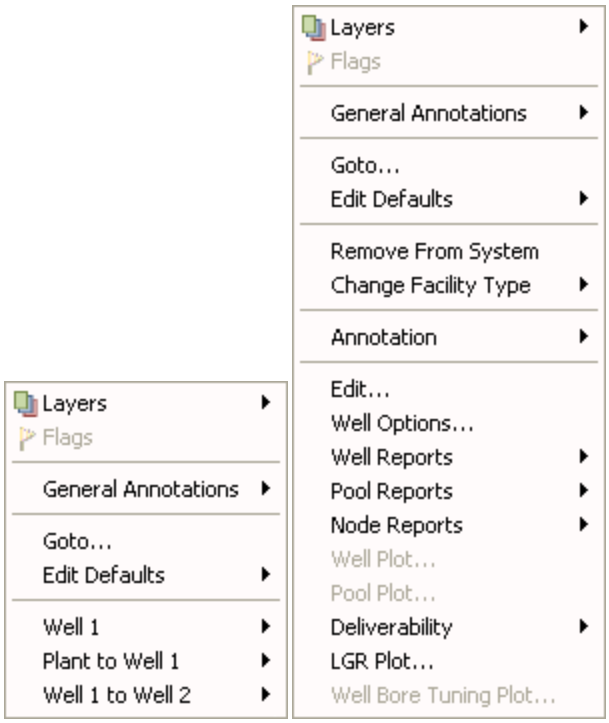
During forecasting or traversing through the display dates after a forecast, the annotation values update with every interval of the forecasting period.

To switch between facilities in the Annotation editor, use the drop-down menu.

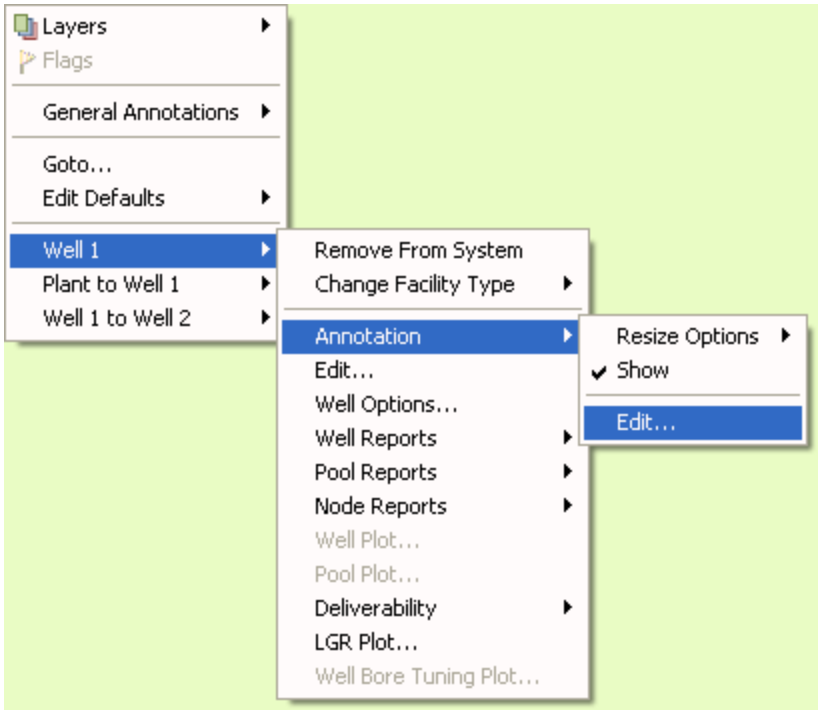


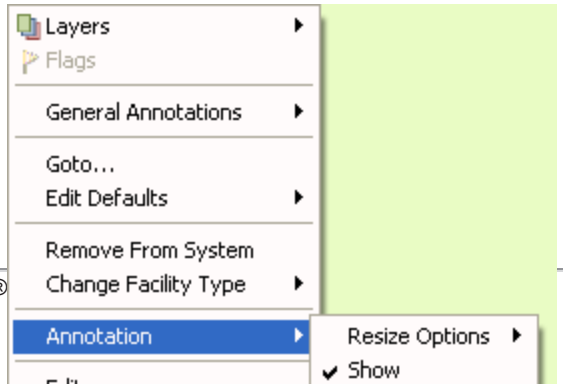
Custom annotations

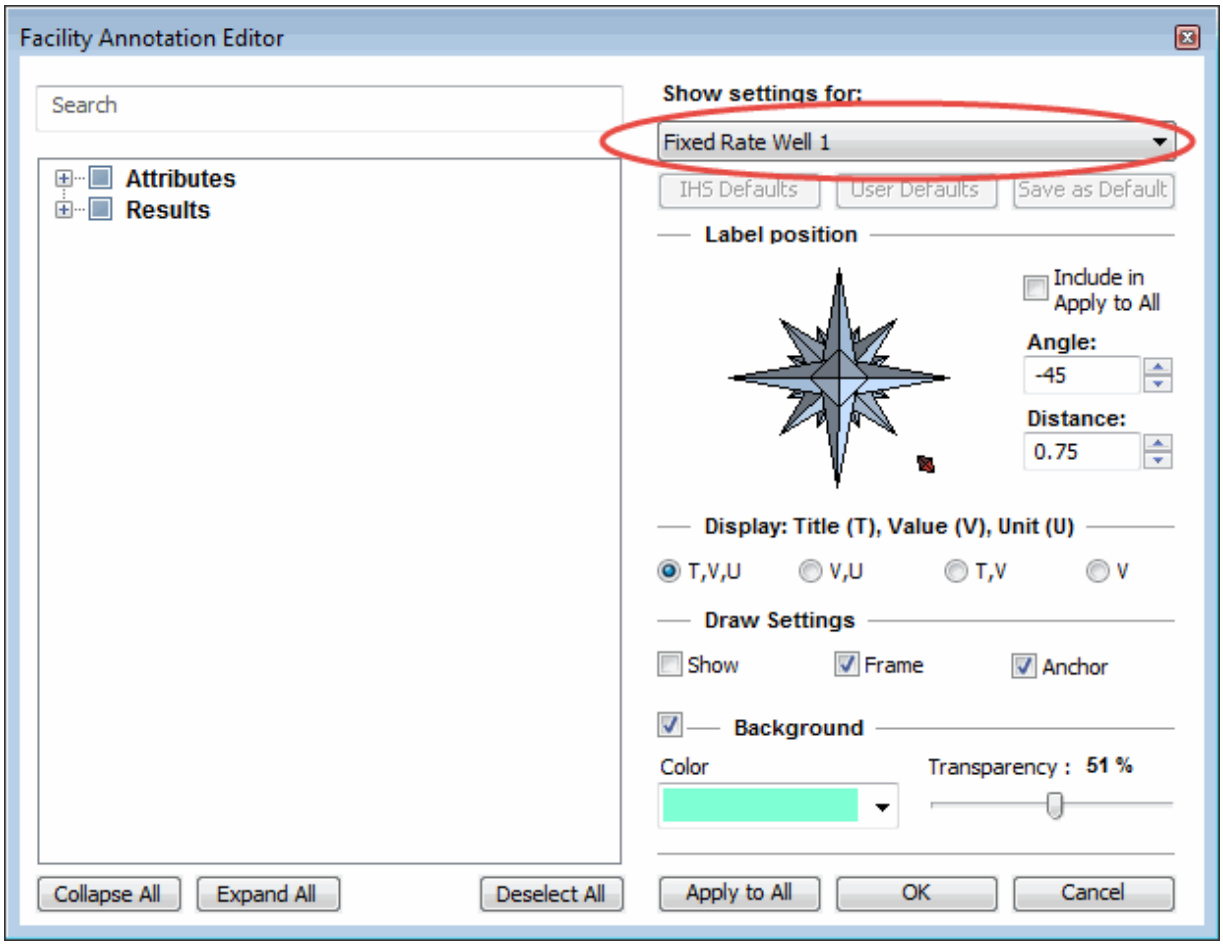
Customized annotations can be set for each facility, if specialized annotations are required. To modify the display options of any facility on the gathering system map, place the cursor over the facility and right-click. You are prompted with one of the following drop menus:



Follow the facility menu to the Annotations options and select the Edit option.







The annotation editor that appears now is specifically for that facility. The name of the facility will appear where the facility type was.

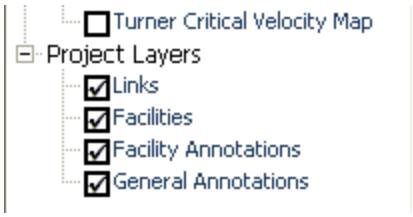
Warning: Each node (no matter what facility type it is) can hold one custom annotation. Creating a custom annotation will overwrite old annotation settings in all other configuration dates. This means that if there was a facility change in a different configuration date, the annotations will display only the custom annotation settings even when the facility types are different. Trying to edit the custom annotations again will only show the new custom settings in the other facility type.

The Apply to All button will apply the current settings to all facilities of the same group. For example, annotation settings for Well 1 will be applied to all well type facilities. Apply to All will also overwrite all custom annotations and reset all annotation positions.

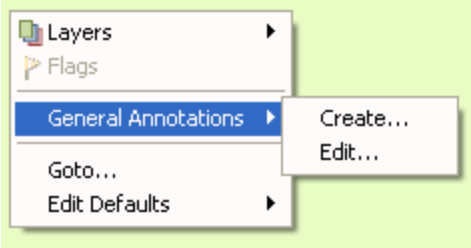
There is an alternative method to restore the annotations to the other configuration dates if clearing the other custom settings or resetting the positions is not an option. Simply return to the date that custom annotation was made for. Change the annotation to the same settings as the default settings for that facility type. The facility's annotation will no longer be considered as a custom setting and the annotations will be return to defaults in the other configuration dates.

General annotations

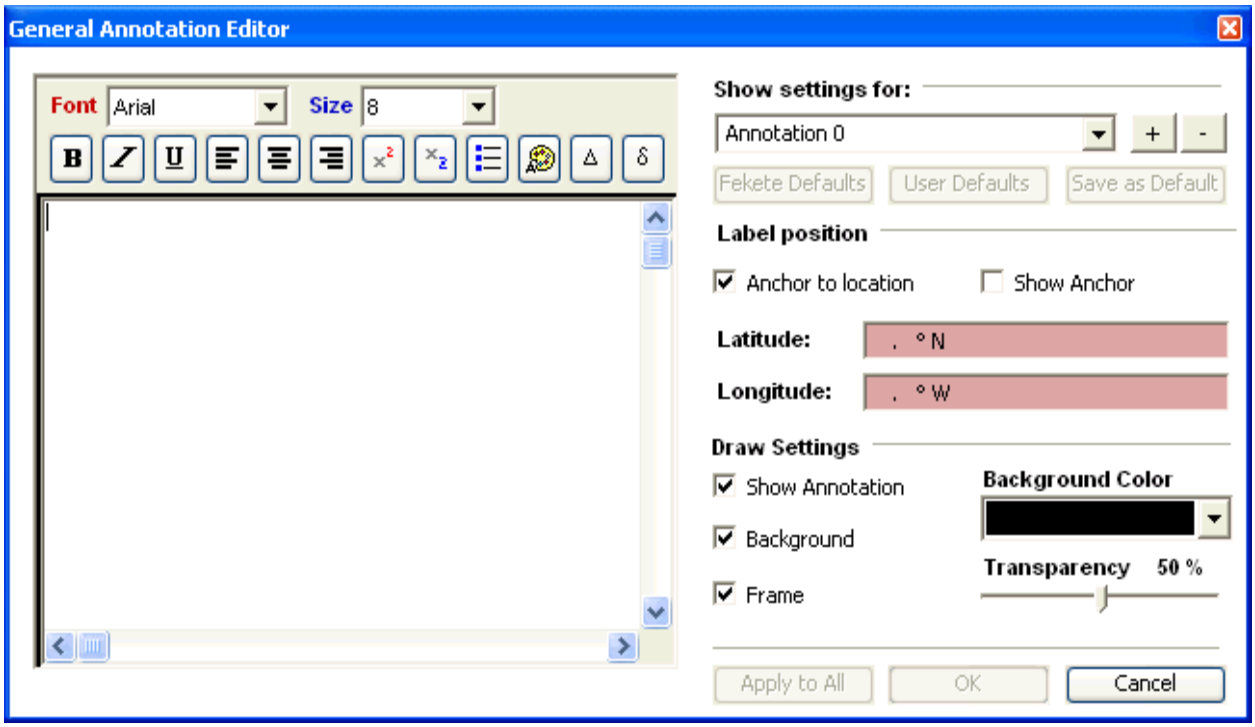
General annotations are used for displaying any other notes or labels anywhere on the map. By default, General Annotations are disabled. Enable them through the Property Manager to display the General Annotations.



To use, right-click the map and select General Annotations then Create to add an annotation or Edit the to modify an existing annotation.

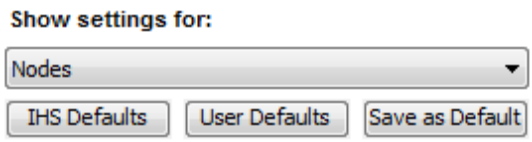


On the left of the General Annotations Editor is where the user can input any text. It has basic font functions such as size, style, bold and underline. Symbols can also be entered using the buttons  and  to express equations.



The right of the editor much like the Facility Annotation Editor, deals with the visual settings and positioning of the annotation.

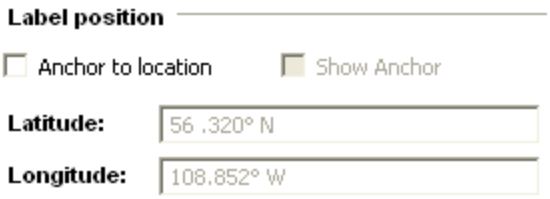
The name of the annotation can be edited directly in the drop box.



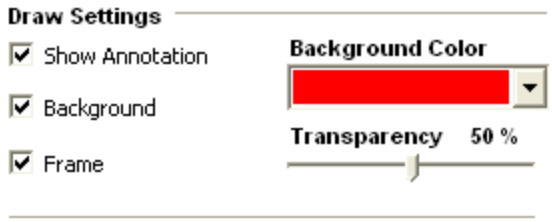
Note: Default options are currently disabled for future enhancements.

Additional annotations can be created in this editor by using the + or removed using the -.

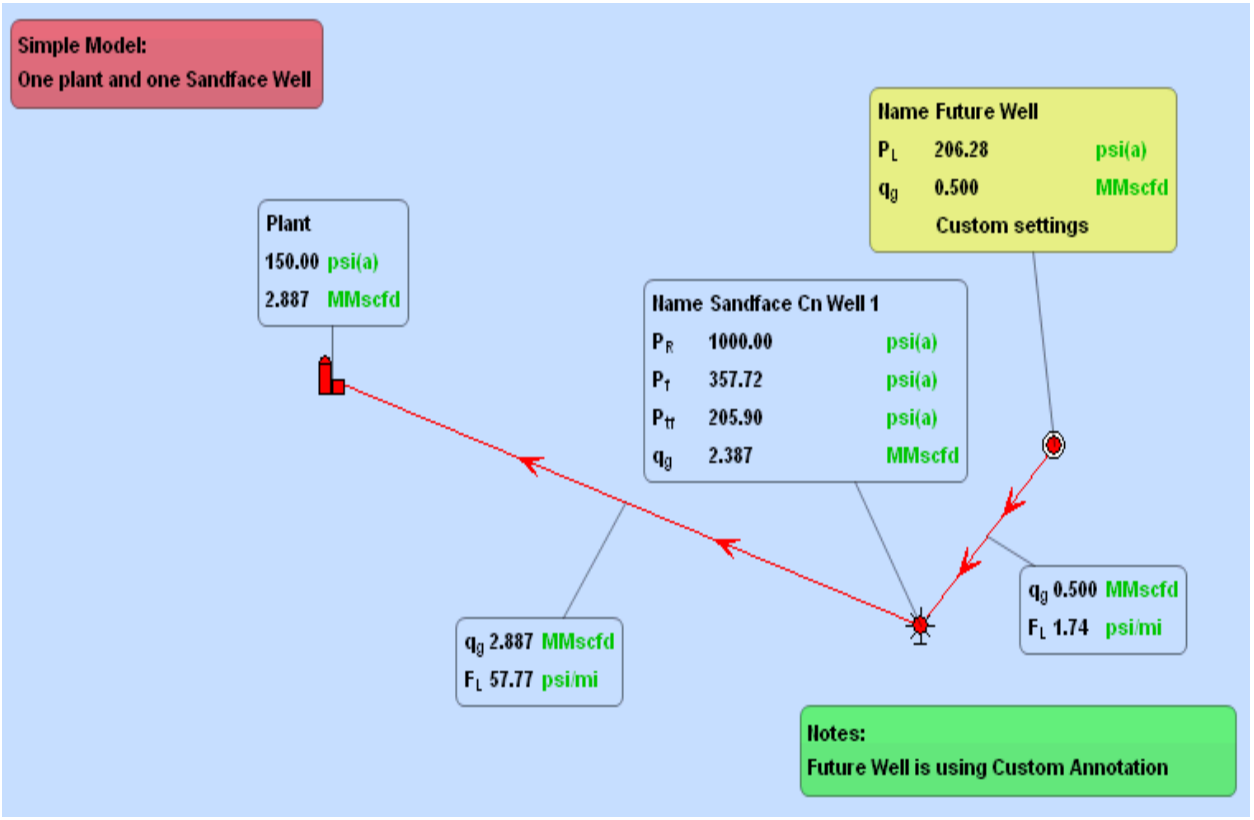
Coordinate of where the mouse was clicked will be automatically used as the anchor location. If the Anchor to Location is not used, the annotation will be defaulted to the upper left corner of the map. Also, an annotation not anchored does not move with the map like a regular Facility Annotation. It will always stay in the users screen when zooming or panning.



The Draw Settings affect how the annotation will look on the map.



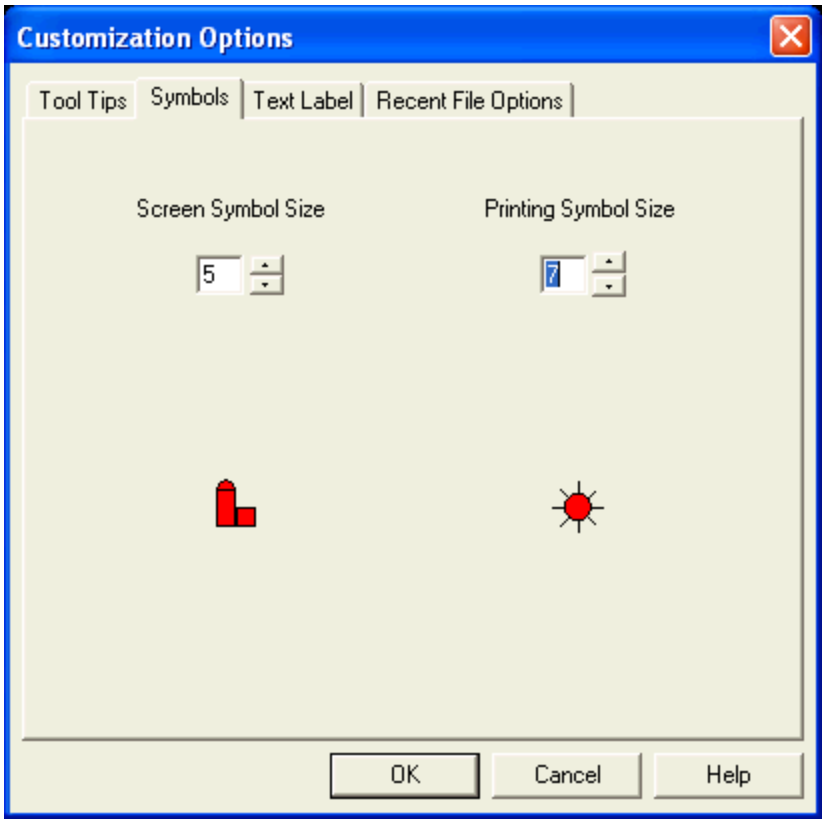
Annotations can be used further enhance the visual presentation of the model.



More display options

You can select the parameters you want displayed in the gathering system map for any facility. The example shown above is for well display options. The user can also choose the position of the display around the facility, as shown on the right hand side of the window.

The size of text and symbols on the map screen can be adjusted by selecting **Customize**, which is found under the**Properties** menu:



Well naming in Merak / Dwight files

Production history can be imported from a Merak (.mer) and Dwight (.dp2) file.

Well naming

For Merak files:

- Well Names will be defined to be the Well ID (record 0001 in the merak file)
- Alias Names will be defined to be the Well Name (record 0002 in the merak file)

Note that the Well ID is used for the Well Name because it insures there is always a unique name.

For Dwight files:

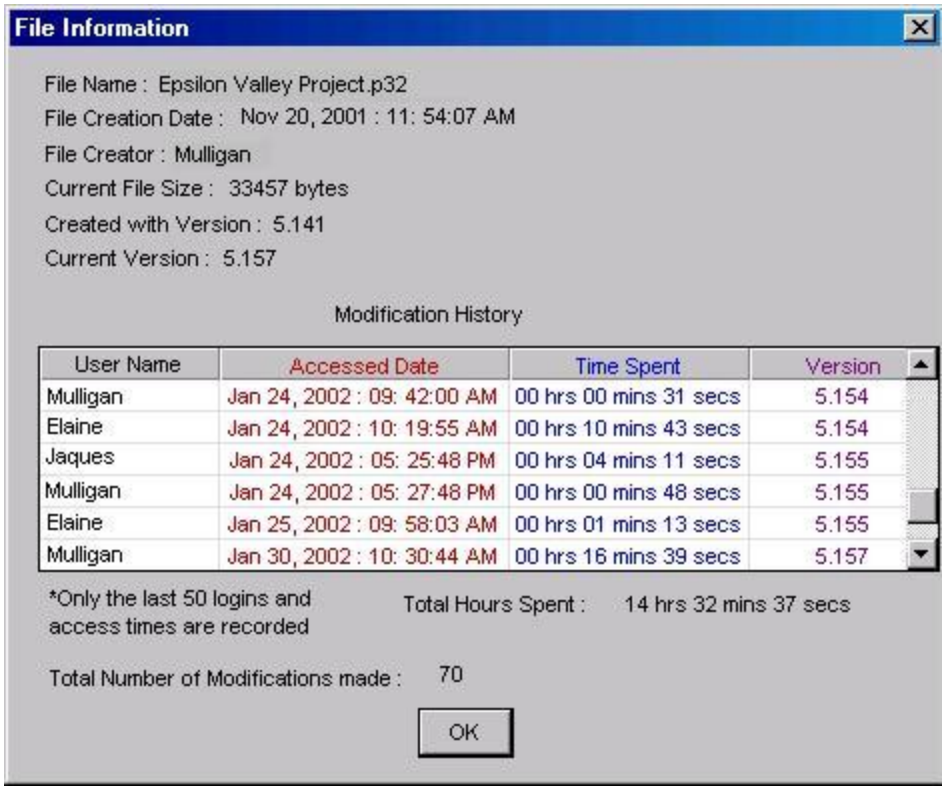
- Well Names will be defined to be the following: "PRODID" from the REC1RCI record + " - " + "APINO" from the REC1ENG record
- Alias Names will be defined to be the following: LEASENAM" from the REC1RCI record + " " + "WELLNO" from the first RECWHDR record + "/" + "the last four digits of the "PRODID" from the REC1RCI record

Note that the combination PRODID and APINO is used for the Well Name because it insures there is always a unique name.

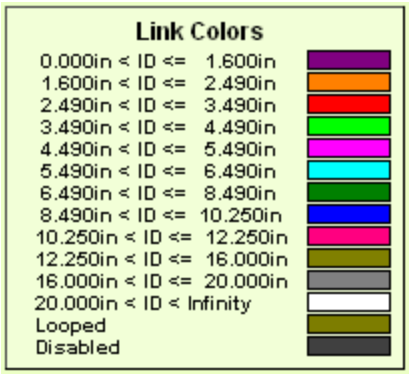
Other diagnostic tools

File information

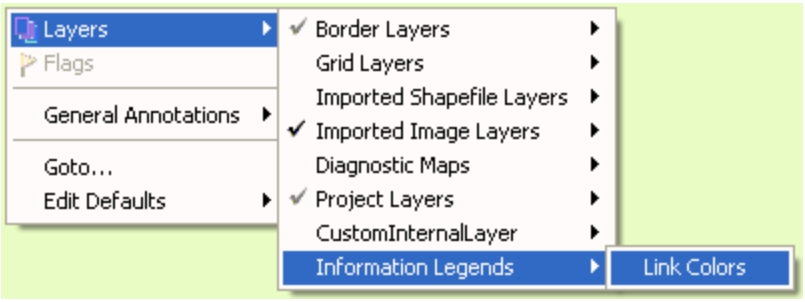
You can access **File Information**under the **Help** menu. It provides the following information about the active file: name, date the file was created, date the file was last modified, version of the software that generated the file and current version.



Link color legend



The Link Colors legend can be added by right mouse clicking on the map and selecting the following.



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Reference materials

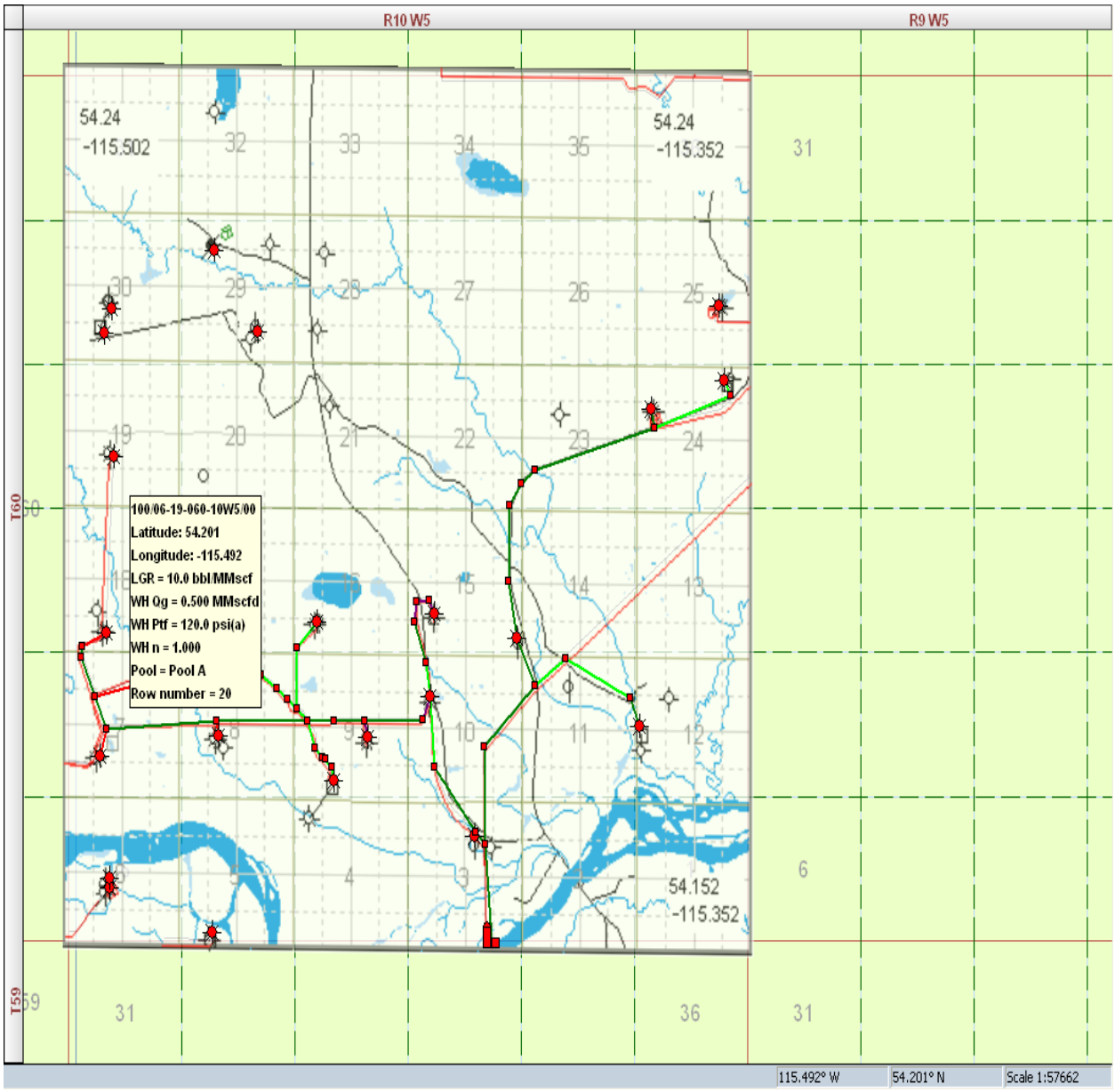
Reference materials include the following:

- GIS theory
- reservoir
- well deliverability
- surface facilities
- pressure loss correlations
- phase volume correlations
- general fluid correlations
- temperature calculations
- Status Window messages
- nomenclature listings
- glossary

S&P Global
Energy

GIS theory

A Geographic Information System (GIS) is a system for gathering, processing and presenting data based on geographical references. In Piper, the GIS displays well data on a map based on one of the standard coordinate systems (DLS, NTS, Lat/Long, etc).



Overview of Mapping Systems

This section describes how locations are displayed using the different mapping systems. There are five grid display modes available in Piper:

- Latitude/Longitude
- Dominion Land Survey (DLS)
- National Topographical System (NTS)
- Cartesian
- Universal Transverse Mercator (UTM)

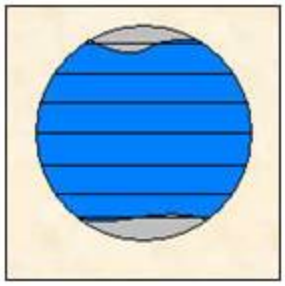
Datum

A datum is a reference from which measurements are made. For Piper's GIS, a geodetic datum is a set of reference points on the earth’s surface against which entities are positioned.

In Canada and the United States, the North American Datum of 1927 (NAD27) and the North American Datum of 1983 (NAD83) are the two official datums used for geodetic systems. Piper currently defaults to NAD83. Latitude/longitude information in NAD83 format will be positioned accurately on the map.

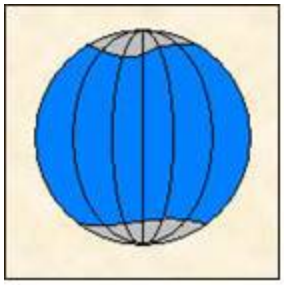
Latitude / Longitude

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. In Piper latitudes in the Northern hemisphere are represented with a positive value and latitudes in the Southern hemisphere are represented with a Negative value.



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. In Piper longitudes in the Western hemisphere are represented with a negative value and longitudes in the Eastern hemisphere are represented with a positive value.



To further divide degrees of latitude and longitude seconds and minutes are used:

- 1 degree = 1 º = 60 minutes
- 1 minute = 60 seconds

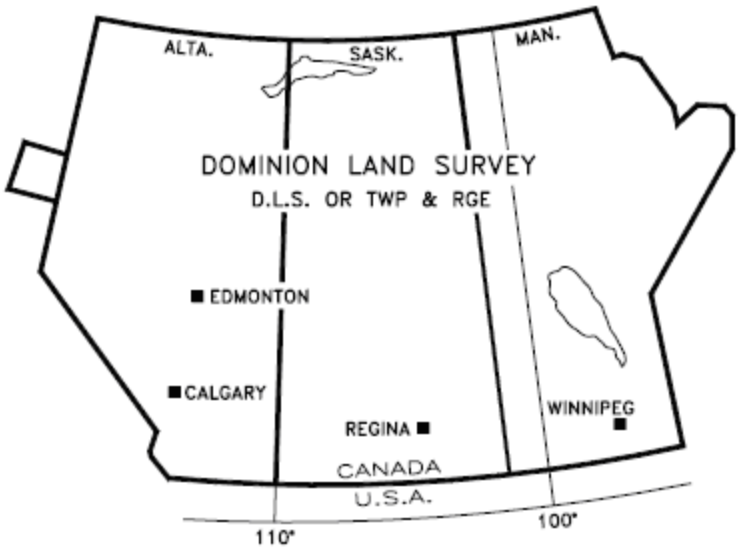
As an example of latitude and longitude, here are the approximate locations of a few cities around the world:

Examples of Latitude and Longitude

Location	Latitude	Longitude	Notes
Greenwich, England	**51o, 29 min N**	**0 o, 0 min**	This is the reference point for longitude.
Calgary, Canada	**51o, 3 min N**	**114o, 3 min W**	This city is located north of the Equator and to the west of Greenwich.
Perth, Australia	**31o, 57 min S**	**115o, 52 min E**	This city is located south of the Equator and to the east of Greenwich.

Dominion Land Survey (DLS)

The DLS system is used in the provinces Alberta, Saskatchewan, Manitoba, and British Colombia in Canada.



Areas in Canada where the DLS system is used

Example Location: 100/04-11-082-04W6/0

We can read the parts of the UWI as the following:

Unique Well Identifier Format	Location Exception	Legal Sub division	Section	Township	Range	Meridian	Event Sequence code
1	00	04	11	082	04	W6	0

Unique Well Identifier format

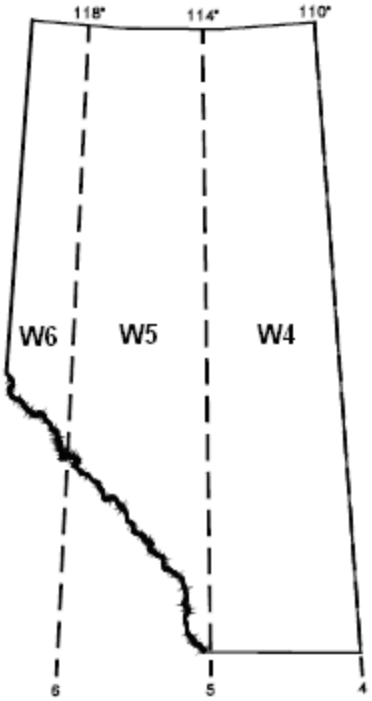
This number identifies the use of a DLS system.

Location Exception code

This is used when there is more than one hole drilled per legal subdivision. For more details on what can be included in the exception code, see EUB Guide 59.

Meridian

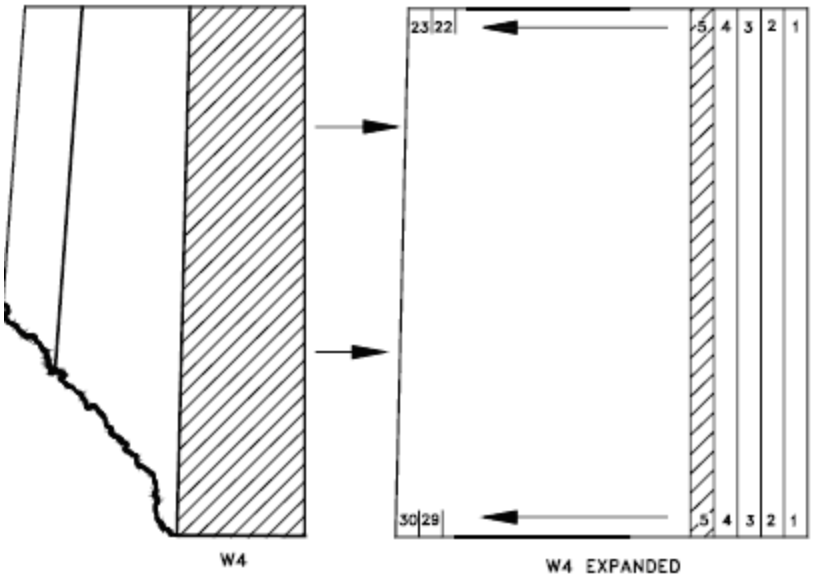
The meridians are 4 degrees of longitude wide that divide the DLS provinces. The West 4 meridian corresponds to 110 degrees west.



The meridians corresponding to Alberta, Canada

Range

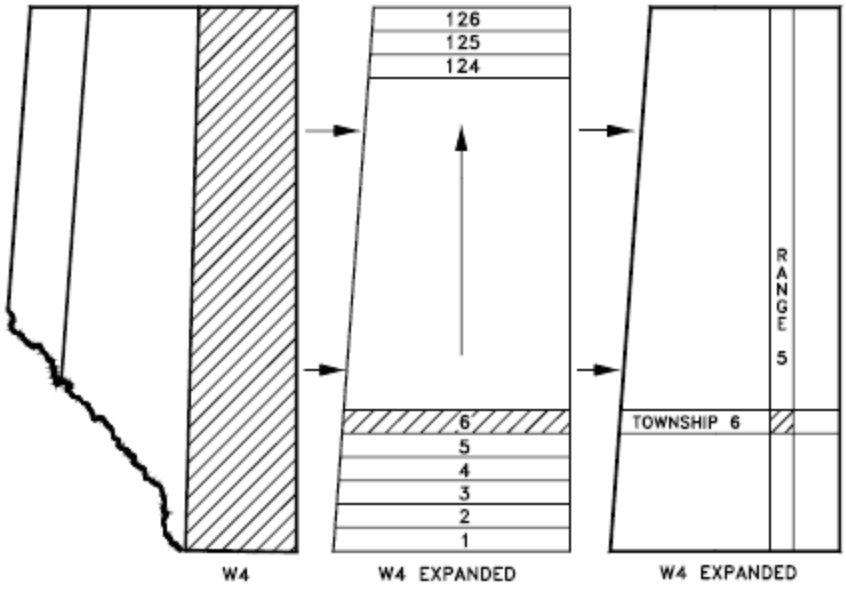
The ranges further divide the meridians. At the southern edge of Alberta, there are 30 ranges per meridian. The number of ranges per meridian decreases as the lattitude increases. Each range is 6 miles (9.7 km) wide.



Ranges in Alberta

Townships

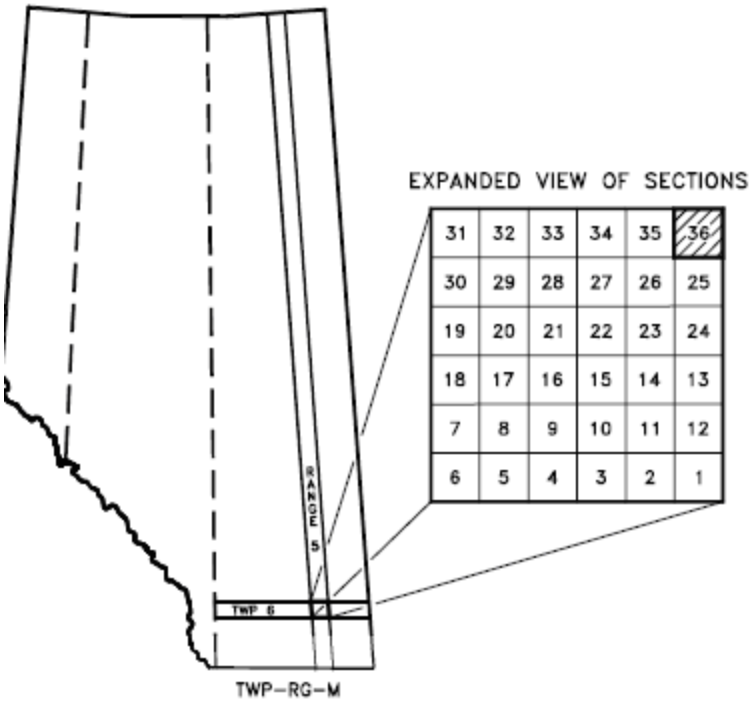
The townships divide the provinces up in the north-south direction. There are 126 townships in Alberta. Each township is 6 miles (9.7 km) north-south.



Expanded view of ranges in Alberta

Sections

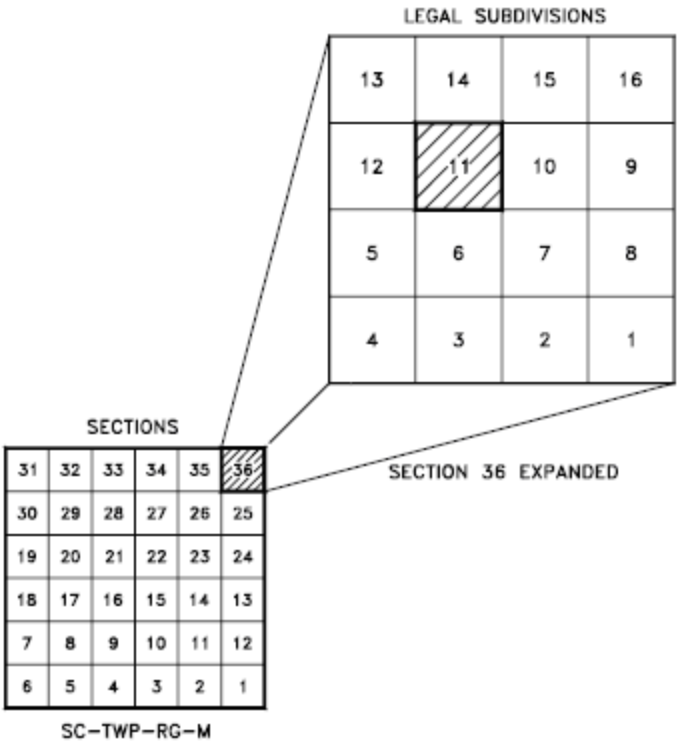
A square one range wide by one township north-south contains 36 sections. Each section is 1 mile (1.6km) per side.



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 1320 ft (402m) per side.



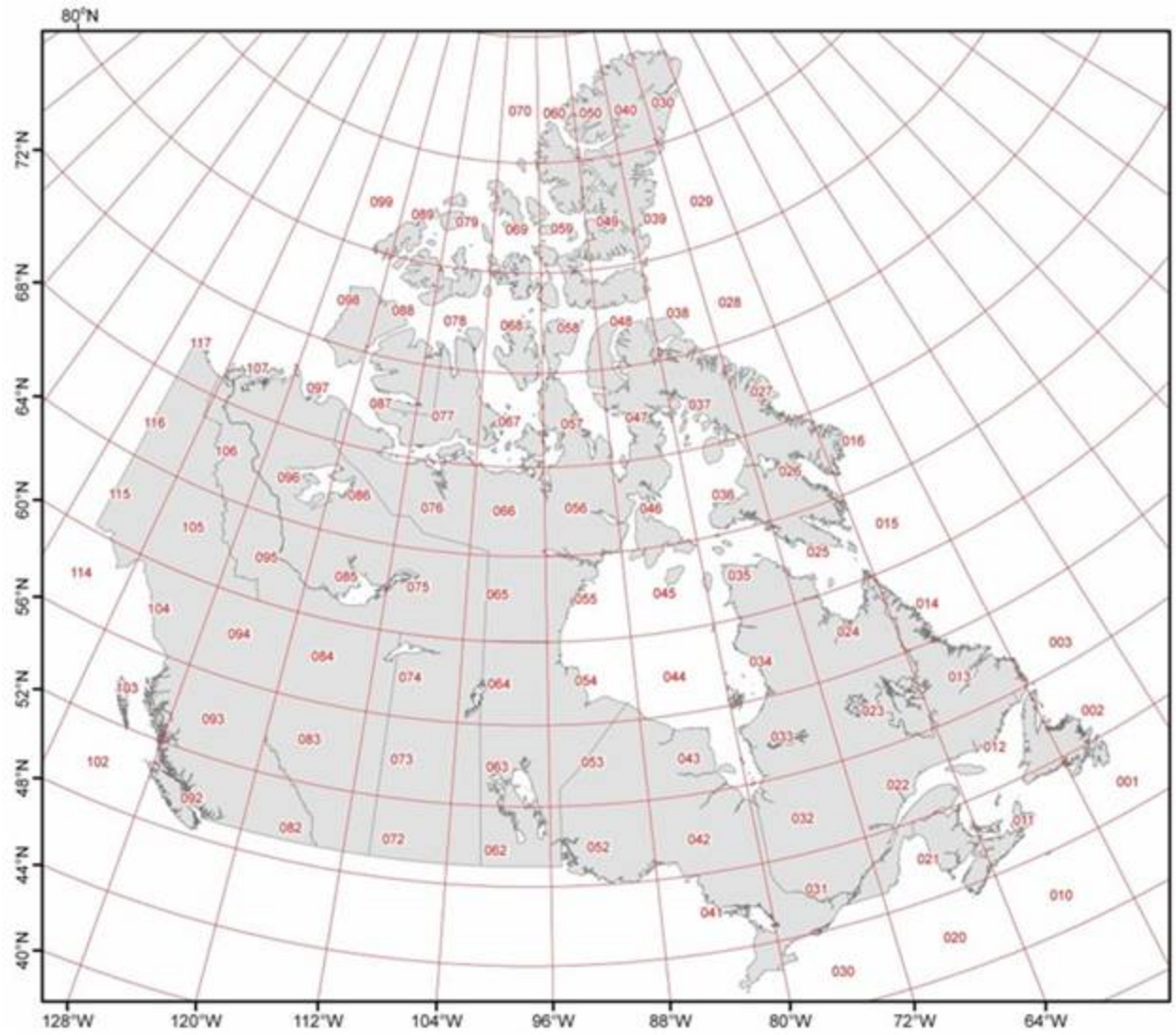
Expanded view of LSD

Event Sequence

Indicates chronological sequence of drilling or completion activities.

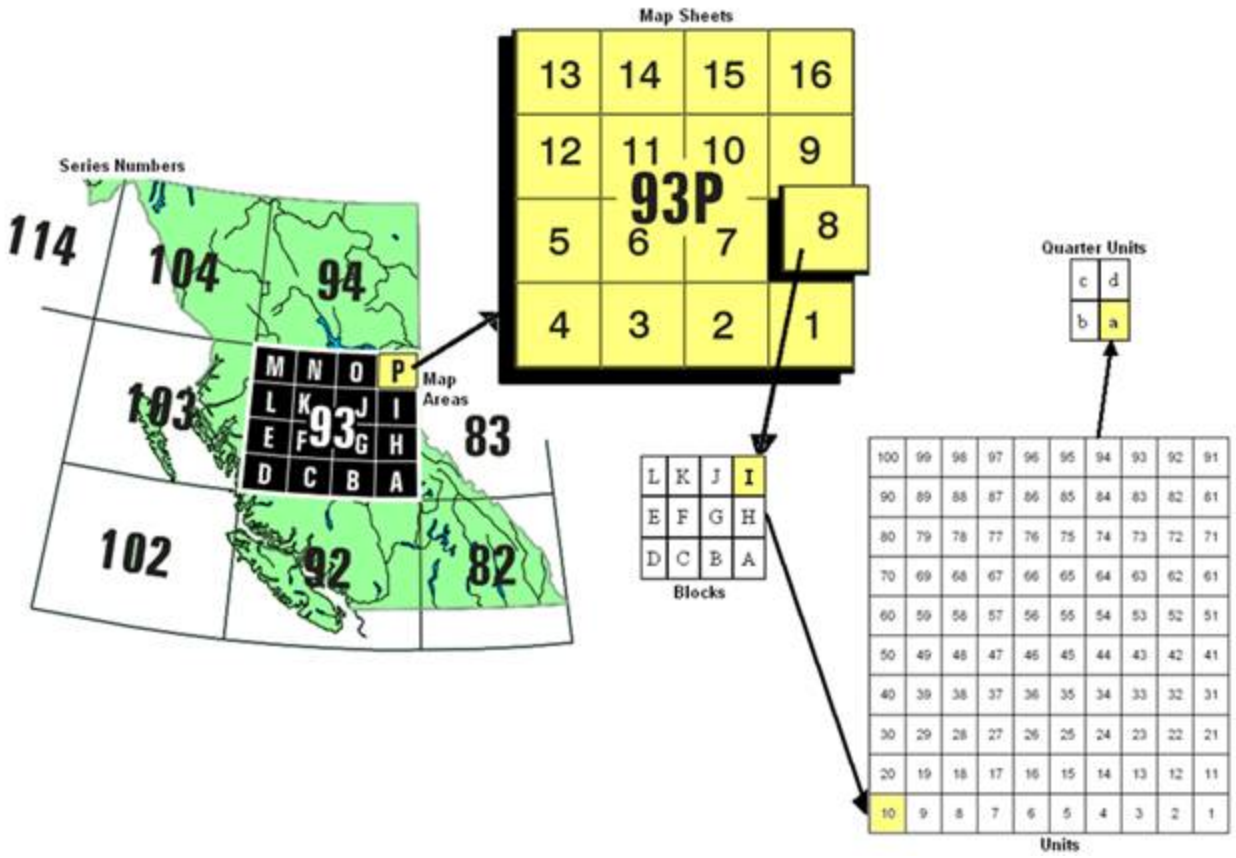
National Topographic System (NTS)

The National Topographic Map Numbering System 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	I	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 Colombia.

Map Areas

The map areas divide the series numbers into 16 pieces that are labelled 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 labelled 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 labelled a to d.

Universal Transverse Mercator (UTM) Grid

The Universal Transverse Mercator 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
317km west	6532km 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.

Cartesian

Cartesian coordinates describe a location in terms of distance from a defined reference point. The Y axis, which corresponds to longitude increases in the east direction. The Y axis, which corresponds to latitude increases in the north direction.

Example location: - 317km, 6532km

X axis (East/West)	Y axis (North/South)
317km west	6532km 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.

References

Well Drilling and Completion Data Filing Requirements, EUB Guide 59, Alberta Energy and Utilities Board, June 2004.

University of Northern British Colombia GIS Lab Website (2009).

S&P Global
Energy

Reference materials

Reference materials include the following:

- GIS theory
- reservoir
- well deliverability
- surface facilities
- pressure loss correlations
- phase volume correlations
- general fluid correlations
- temperature calculations
- Status Window messages
- nomenclature listings
- glossary

Reservoir

With Piper, you can define numerous types of reservoirs that can be connected to wells. The first four of these reservoirs use material balance techniques. The transient reservoirs use direct solution methods based on the input of reservoir characteristics. The types of reservoirs supported by Piper are the following:

- Volumetric Depletion Reservoir
- Connected Reservoir
- Water Drive Reservoir
- Geo-pressured Reservoir
- Transient Reservoir

Volumetric Depletion (Tank-Type) Reservoir

In a Volumetric Depletion Reservoir the internal energy of the gas is the primary drive mechanism that moves the gas towards the surface. As gas is produced from the reservoir, the pressure in the reservoir declines. The relationship between the compressibility adjusted pressure in the reservoir and the cumulative gas produced will follow a straight line. This is often referred to as the P/Z plot. The equation used by Piper to describe the relationship is:

$$\frac{P_1}{Z_1} = \frac{P_i}{Z_i} - \frac{P_i / Z_i}{IGIP} \bullet G_p$$

Required Input for Volumetric Depletion Reservoir

The Volumetric Depletion reservoir is the assumed reservoir used by Piper unless the user specifies another reservoir type. Five inputs are required to define a Volumetric Depletion reservoir:

- Original Gas in Place
- Cum Gas to Date
- Original Reservoir Pressure
- Reservoir Temp
- Reservoir Depth
- Recovery Factor

The Original Gas in Place (OGIP) is the gas contained in the reservoir before production began. The Cum Gas to Date is the amount of gas extracted from the reservoir up to the date of the current forecast configuration. The Original Reservoir Pressure is the initial shut-in pressure of the reservoir before production commenced. The current reservoir pressure can be calculated from these three inputs.

The Reservoir Temp is the current temperature of the reservoir. It is used to adjust for temperature dependence of compressibility effects.

The Pool Depth is the depth of the pool, measured to the mid point of perforations.

The Recovery Factor can be used to stipulate the economic recovery limit for the reservoir.

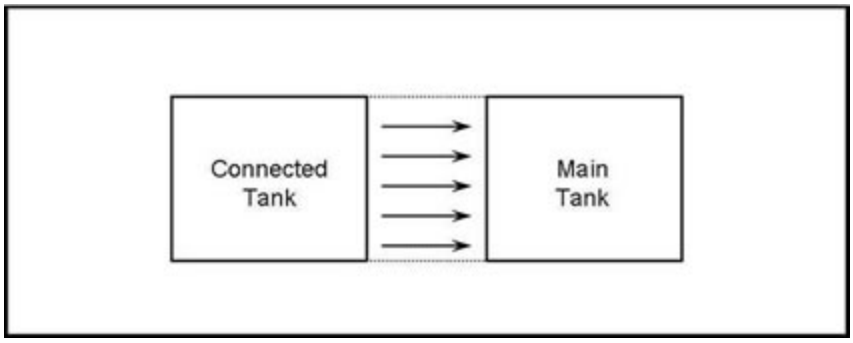
Connected Reservoir

Many gas reservoirs have areas of high permeability that are in communication with surrounding areas of low permeability. This contrast in permeability, which is typical of "tight gas reservoirs", affects the P/Z relationship that the reservoir follows as it depletes.

The existence of such heterogeneity complicates the material balance analysis because the high permeability area will deplete at a faster rate than the low permeability area. The low permeability area will then act as a recharging mechanism to the high permeability area. This interaction renders the material balance plot non-linear (P/Z plot is concave upward).

Often the reserves contained in the low permeability region are significant, and can be larger than those in the high permeability region. The existence of the low permeability region will often affect the depletion profile of the high permeability region. Piper uses the Connected Reservoirs theory to model this behavior.

The connected reservoir can be visualized as two tanks in communication with each other, as shown in the figure below:



In the connected reservoir model used by Piper production of gas takes place from the main tank only. The connected tank, referred to as the **Connecting Reservoir**, acts as a low permeability recharging pool. This pool is depleted indirectly into the main tank where production takes place.

The pressure behavior of the two communicating tanks is described by a material-balance equation written for each compartment:

$$P_1 = \frac{P_i Z_1}{Z_i}\left[\frac{IGIP_1 - G_p + G_i + G_{T12}}{IGIP_1 \bullet \left[1 - PV_{ce}\right]}\right]$$

$$P_2 = \frac{P_i Z_2}{Z_i}\left[\frac{IGIP_2 - G_{T12}}{IGIP_2}\right]$$

P1 and P2are the pressures in the main tank and connected tank respectively. The two material-balance equations are coupled through the GT12term, which represents the cumulative gas influx from the connected tank (designated with the subscript '2') to the main tank (designated with the subscript '1').

The degree of communication between the two tanks is characterized by a transfer relationship. Piper utilizes the following transfer relationship:

$$q_{12} = C \bullet (P_1 - P_2)$$

where 'C' is the transfer coefficient.

Required Input for Connected Reservoir

To use the Connected Reservoir Module in Piper, three inputs are required.

- Original Gas in Place
- Transfer Coefficient
- Cum Gas Transferred

These inputs all pertain to the connected reservoir. The 'main tank' is defined in the pools menu in the same manner you would define a simple Volumetric Depletion Reservoir.

The Original Gas in Place is the gas contained within the connected reservoir before production commences. The Transfer Coefficient is a constant that defines the transfer of gas from the connected to tank to the main tank. The Cum Gas Transferred is the amount of gas transferred from the connected tank to the main tank up to the date of the current forecast configuration.

The connected reservoir module is most often used for a reservoir that is already exhibiting behavior that deviates from a straight line P/Z plot. In such cases the Transfer Coefficient and Cum Gas Transferred can be adjusted to accurately mimic the P/Z versus Cum relationship being observed. F.A.S.T. MBA™, used along with the production and pressure history for the reservoir, can be used to fit the Connected Reservoir model to the history.

Water Drive Reservoir

Many gas reservoirs are associated with adjacent aquifers from which there is water expansion that encroaches upon the reservoir as gas is produced. Water encroachment provides an important source of pressure support for the reservoir and must be taken into account when performing material balance calculations. The gas expansion dynamics no longer act in isolation to dictate a straight line P/Z versus Cum relationship. Instead, the P/Z plot will trend concave up, with the extent of the concavity being dictated by the strength of pressure support being provided by the underlying aquifer.

The material balance equation for a gas reservoir with water drive accounts for gas expansion characterizing a Volumetric Depletion Reservoir as well as the effect of the influx of water from the adjacent aquifer.

$$\frac{P_1}{Z_1} = \frac{P_i}{Z_i}\left[\frac{IGIP - G_p}{IGIP \bullet \left[1 - PV_{we}\right]}\right]$$

Required Input for Water Drive

The Piper Water Drive requires input of three parameters:

- Aquifer Volume
- Transfer Coefficient
- Cum Water Transferred

Piper treats the influence of the aquifer in a manner similar to the way it treats the influx of gas from a connected reservoir. The influx of water into the reservoir is assumed to follow the following deliverability relationship.

$$q = C \bullet (P_R - P_a)$$

Where 'C' is the Transfer Coefficient.

The aquifer is assumed to initially be at the same pressure as the original reservoir pressure. Because the pressure of the reservoir and that of the aquifer are the same, there is no influx of water into the reservoir for the first time step (either a daily or monthly period) and the reservoir follows a Volumetric Depletion relationship. Beyond the first month, a pressure difference does exist between the reservoir and the aquifer. Thus there will be flow from the aquifer to the reservoir, and that flow will be dictated by the deliverability relationship described above.

At the end of each forecast time step the change in pressure of the aquifer due to the reduction of water within the aquifer is determined by the following compressibility equation:

$$W_e = c \cdot W_i \cdot (P_i - P)$$

This equation relates the amount of water transferred during the time step (We), to the initial aquifer volume at the beginning of the time step (Wi), the total rock and water compressibility (c), determined internally by Piper, and the change in pressure of the aquifer during the time step.

Geo-Pressured Reservoir

In a Geo-Pressured Reservoir, the impact of the compressibility of the connate water and rock cannot be ignored. The expansion of the connate water and rock act as additional drive mechanisms to the primary gas expansion drive mechanism.

The material balance equation for a Geo-Pressured Reservoir accounts not only for the gas expansion characterizing a Volumetric Depletion Reservoir but as well for the expansion of the rock and water:

$$\frac{P_1}{Z_1} = \frac{P_i}{Z_i}\left[\frac{IGIP - G_p}{IGIP \cdot \left[1 - PV_{ce}\right]}\right]$$

Required Input for Geo-Pressured Reservoir

The Piper Geo-Pressured Reservoir module requires input of two parameters:

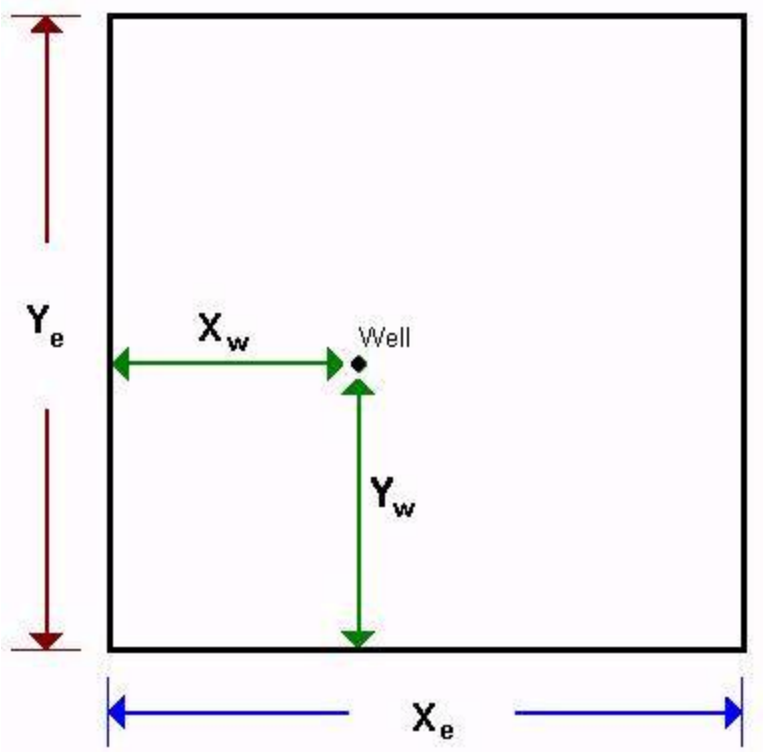
- Connate Water Saturation
- Rock Compressibility

Piper will assume that these properties will be constant through the life of the reservoir, and will apply these properties to the material balance to account for changes in rock and water compressibility. Note that the water compressibility, also required in the calculation, is determined internally by Piper.

Analytical Models

Models - Radial

Rectangular reservoir with a vertical well located anywhere inside.



The Radial Model is actually a homogeneous **rectangular reservoir model**, with a vertical well located anywhere inside. The model is analytical and uses Green's functions and method of images to calculate a fully integrated wellbore pressure history from early-time, through transition and into boundary dominated flow.

The model incorporates storage and skin effects. Rate dependent (turbulence) skin can also be accommodated (using a semi-analytical method) by entering a "D" turbulence factor.

The x and y dimensions of the reservoir can be set to any value above zero, and location of the well may be set to anywhere within the reservoir boundaries.

Pseudo-time is used for gas wells, to accommodate changing gas compressibility with reservoir pressure.

Parameters

Pi = initial pressure

k = permeability

h = net pay

s = skin (may be left blank)

D = turbulence factor (may be left blank)

C_D = storage coefficient (may be left blank)

x_e = reservoir length

y_e = reservoir width

x_w = x position of well within reservoir

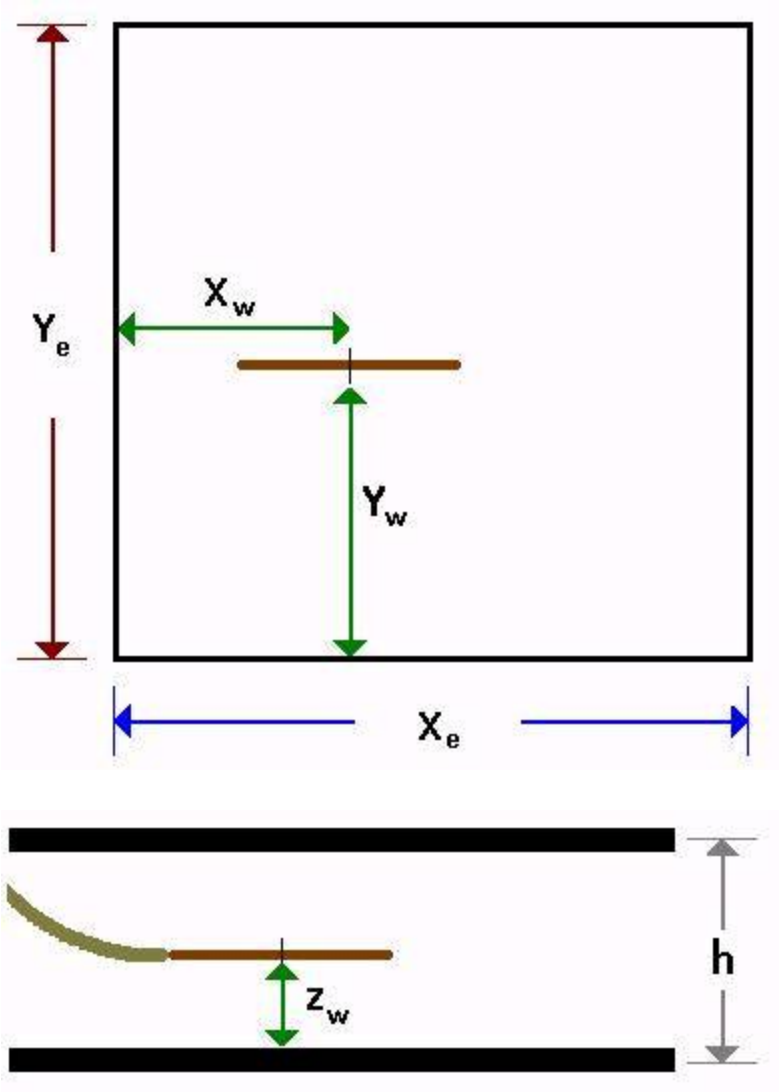
y_w = y position of well within reservoir

O_IP = original gas/water/oil in place

Area = extent of reservoir

Models - Horizontal

Rectangular reservoir with a horizontal well located anywhere inside.



The Horizontal Well Model is a homogeneous **rectangular reservoir model**, with a horizontal well located anywhere inside. The model is analytical and uses Green's functions and method of images to calculate a fully integrated wellbore pressure history from early-time, through transition and into boundary dominated flow.

The model incorporates storage and skin effects. Rate dependent (turbulence) skin can also be accommodated (using a semi-analytical method) by entering a "D" turbulence factor.

The model allows three dimensional anisotropy, providing inputs for permeability in the x, y and z directions. The effective wellbore length and stand-off height are also be included as model inputs.

The x and y dimensions of the reservoir can be set to any value above zero, and location of the well may be set to anywhere within the reservoir boundaries, provided the horizontal wellbore does not

overlap any of the boundaries. Thus, it is possible to model the combined effects of horizontal wells and boundary flow in any number of different geometrical configurations.

Pseudo-time is used for gas wells, to accommodate changing gas compressibility with reservoir pressure.

Parameters

P_i = initial pressure

k_x, k_y, k_z = permeability in the x, y and z directions

x_f = fracture half-length

L_e = effective wellbore length

z_w = z position of horizontal well within reservoir

s = skin

D = turbulence factor (also known as non-Darcy coefficient or turbulence skin effect)

C_D = wellbore storage coefficient

x_e = reservoir length

y_e = reservoir width

x_w = x position of well within reservoir

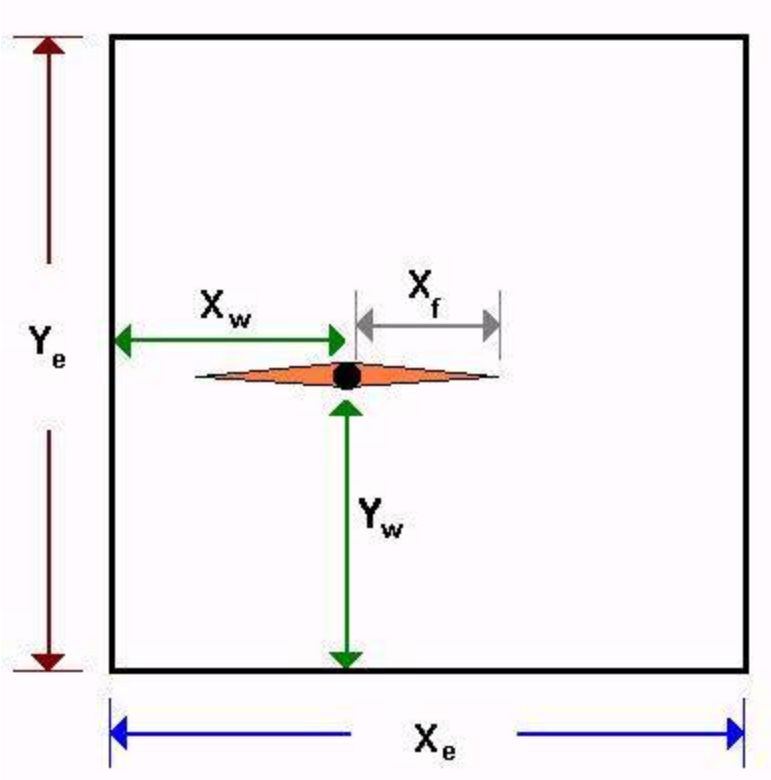
y_w = y position of well within reservoir

O_IP – original gas/water/oil in place

Area – extent of reservoir

Models - Fracture

Rectangular reservoir with a vertical infinite conductivity fracture located anywhere inside.



The Fracture Model is a homogeneous **rectangular reservoir model**, with a vertical hydraulic fracture (of infinite conductivity) located anywhere inside. The model is analytical and uses Green's functions and method of images to calculate a fully integrated wellbore pressure history from early-time, through transition and into boundary dominated flow.

The model incorporates storage effects. Fracture half-length and fracture face skin may be specified by the user, also. Rate dependent (turbulence) skin can also be accommodated (using a semi-analytical method) by entering a "D" turbulence factor.

The x and y dimensions of the reservoir can be set to any value above zero, and location of the well may be set to anywhere within the reservoir boundaries, provided the fracture does not overlap any of the boundaries. Thus, it is possible to model the combined effects of fracture and boundary flow in any number of different geometrical configurations.

Pseudo-time is used for gas wells, to accommodate changing gas compressibility with reservoir pressure.

Parameters

P_i = initial pressure

k = permeability

x_f = fracture half-length

sc = choke skin (may be left blank)

D = turbulence factor (may be left blank)

C_D = storage coefficient (may be left blank)

x_e = reservoir length

y_e = reservoir width

x_w = x position of well within reservoir

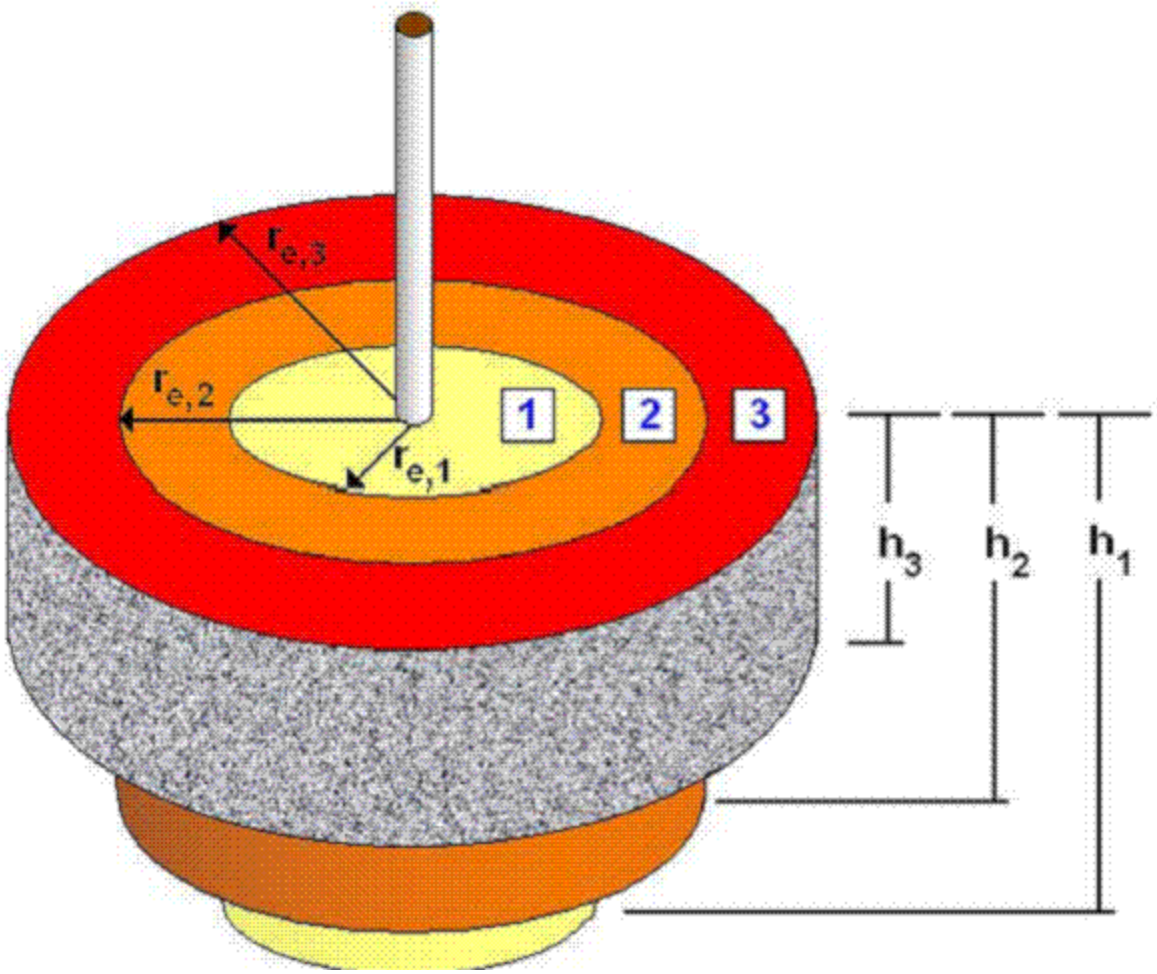
y_w = y position of well within reservoir

O_IP = original gas/water/oil in place

Area = extent of reservoir

Models - Composite

A **circular reservoir** formed of concentric regions with a vertical well located at the center. The following schematic shows three regions, each with their own net pay value.



The composite model is composed of homogeneous concentric rings, with a vertical well located at the center.

The model is analytical and calculates a continuous sandface pressure history from early-time, through transition and into boundary dominated flow.

The model incorporates storage and skin effects. Rate dependent (turbulence) skin can also be accommodated (using a semi-analytical method) by entering a "D" turbulence factor.

The outer radius (r_o) for each ring can be set to any value that is greater than the r_o value for an inner ring. It is also possible to remove regions until all that remains is one region. Each region can have its own net pay (h).

Pseudo-time is used for gas wells, to accommodate changing gas compressibility with reservoir pressure.

Parameters

P_i = initial pressure

k = permeability

h = net pay

s = skin (may be left blank)

D = turbulence factor (may be left blank)

C_D = storage coefficient (may be left blank)

r_o = region outer radius

O_IP = original gas/water/oil in place

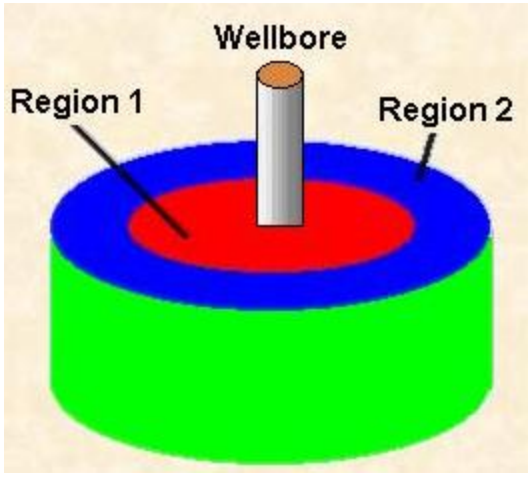
Area = extent of reservoir

Legacy Transient Reservoir

The Legacy Transient Reservoir models used in Piper are an approximation of the true analytical models. In many cases the approximation, which does not incorporate superposition, has proved to be sufficient. Note that the legacy transient well models will not match results from RTA for the same model type.

The Legacy Transient Reservoir model is defined by a number of parameters that determine the rate response of a reservoir to changes in pressure, such as permeability, porosity and skin (a full list is discussed below in the Required Input section). The Legacy transient well pool is a single well pool that behaves on the basis of tank type depletion.

A Transient Reservoir is illustrated pictorially below:



Piper allows for one of two boundary conditions to be associated with the reservoir; a radial finite boundary reservoir or infinite acting reservoir. The finite boundary reservoir option assumes a 'no-flow' boundary at the reservoirs extent whereas the infinite reservoir does not.

The reservoir may also be defined as either homogeneous through its extent, or as consisting of two regions, each with distinct properties of permeability and net pay. In Piper, a transient reservoir consisting of two regions is called a composite reservoir.

Required Input for a Transient Reservoir

The properties required to use the Transient Reservoir in Piper are as follows:

- Drainage Area
- Permeability
- Net Pay
- Distance to Boundary
- Total Porosity
- Skin Damage
- Wellbore Radius
- Water Saturation

Permeability

The permeability of a reservoir is a measure of the ability of a fluid to flow through rock as a function of pressure. Permeability is a property of the rock and is independent of the type of fluid. This means that the absolute permeability of a rock is the same whether the fluid traveling through it is oil, gas or water. In a petroleum reservoir, the rock is usually not fully saturated with a single phase fluid. Generally saturations in the reservoir rock will consist of different amounts of gas, oil and water. These saturations will change the effective permeability of the rock.

Piper requires the input of Permeability for transient wells.

Net Pay

This is the thickness of the formation that contributes to the flow of fluids. It is determined from logs or core, and can be different from the gross pay or the perforated interval. In the case of inclined wellbores in dipping formations, the net pay is measured perpendicular to the angle of dip.

Piper requires the input of Net Pay for transient wells.

Distance to Boundary

The distance to the boundary refers to the radial distance within the transient reservoir where reservoir properties (such as permeability, net pay, porosity and compressibility) and fluid parameters (such as viscosity) remain constant. Once the parameters appear to change, the limits of that zone have been reached.

In Piper the distance to boundary only needs to be defined for composite transient wells. For homogeneous finite transient wells, the distance to boundary is calculated directly from the area input. For infinite wells the distance to boundary is not required.

Total Porosity

The total porosity is the percentage occupied by the pore space, no matter what fluids are contained in the pore space. It is obtained from core or log analysis.

Most pressure transient analyses assume that the total porosity is filled with a single phase fluid, such that the total porosity equals the porosity to that specific fluid. In reality this is rarely the case, and the total porosity is usually filled with a mixture of oil, gas and water.

The total porosity has only a small effect during transient flow analysis but it has a significant effect during pseudo-steady state flow.

Piper requires the input of Total Porosity for transient wells.

Total Compressibility

In a reservoir, which consists of rock and pore space occupied by oil, water and/or gas, the total compressibility is the sum of several components. It takes into account the oil saturation, oil compressibility, water saturation, water compressibility, gas saturation, gas compressibility and the rock compressibility:

The compressibility of oil, water and the formation are of the same order of magnitude (10-6 1/psi) whereas the compressibility of gas is one or two order of magnitude larger. Therefore, if there is any gas present in the reservoir, the total compressibility is dominated by the gas compressibility component.

In transient flow analysis, the total compressibility has only a small effect. However, it has a significant effect during pseudo-steady state flow.

Piper requires the input of Total Compressibility for transient wells.

Skin Damage

The skin effect is a measure of the amount of damage or improvement to the formation in the vicinity of the wellbore.

Damage can be caused by drilling fluids, migration of fines, invasion, and results in a reduced permeability near the wellbore and a positive skin. The magnitude of the positive skin effect is generally 0 to 50 but can be as high as 200.

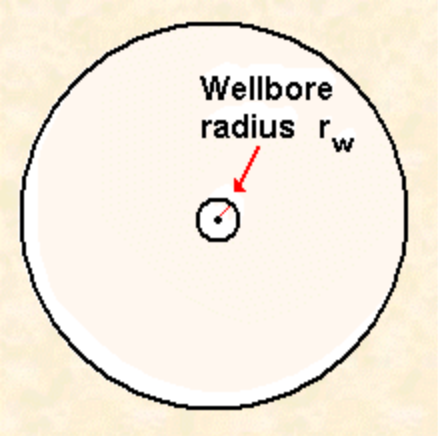
Improvement can be caused by acidizing or fracturing the formation and results in an increased effective permeability near the wellbore and a negative skin. The magnitude of the negative skin effect is generally 0 to -5.

The skin effect is a dimensionless quantity. It is defined as the difference between the "actual" and "ideal" dimensionless pressure drop in a reservoir.

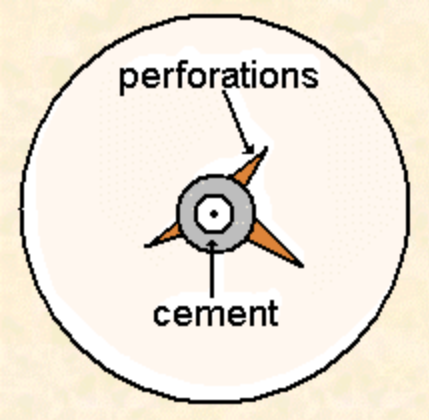
An alternative concept to the skin effect is the "effective wellbore radius". This states that a well with a negative skin is equivalent to a well with a larger wellbore radius, while a well with a positive skin is equivalent to a well that has a smaller "effective wellbore radius".

Piper requires the input of Skin Damage for transient wells.

Wellbore Radius



In real life, the area of contact between the wellbore and the formation is rarely cylindrical. It depends on the perforations and is also affected by the type of perforating gun, casing, cement (see figure below).



Use of a Material Balance and Transient Wells

Transient wells are associated with both reservoir characteristics defined in the Transient Well editor, as well as characteristics defined the Pools editor.

Within the Pools editor, the Original Gas is Place of a Transient well is calculated from the Transient characteristics that are defined in the Transient Well editor. For a infinite pool transient well, this column will be left blank.

The cumulative production of a transient well can be defined in the pools menu. However, if a cumulative production is defined, it should be done so by defining a corresponding start date for the well in the Transient Well editor. A transient well that has associated with it a cumulative production but not a backdated start date, or conversely has a backdated start date but no cumulative production, will result in a mismatch between the material balance and the transient production. The results of this sort of mismatch are unrealistic and should be avoided.

Using Wellbores with Transient Wells

Piper now allows for wellbores to be associated with transient wells. The integration of a wellbore into a transient well will allow for the geometry of the wellbore to affect the well performance. Probably the most significant impact of this functionality is if the user elects to turn either the Turner or Coleman correlation on (found within the wellbore descriptions editor). With the selection of either the Turner or Coleman correlation, the ability of the well to lift liquids will be considered. In the event that the well cannot lift liquids, the well will load with liquids, following the loading procedure described in the wellbore tuning section of this Help.

Using Piper with Pressure Transient Analysis Software

Care must be taken when comparing results of Piper transient wells to the results of pressure transient analysis software. The results obtained by Piperare based on pressures obtained at the wellhead. Thus, they take into account the effect of pressure losses within the wellbore. This is in contrast to PTA software programs, which deal directly with pressure at the sandface.

Use of Pseudo pressure for Transient Wells

Piper the transient reservoir model has been modified to account for the effects of pseudo pressure. Previous versions of Piper used an approximation, the P-squared method, to estimate the change in pressure and compressibility with depth. The result of this change is that Piperwill model transient wells more accurately.

Because of the change introducing the use of pseudo pressure, transient wells defined in previous versions of Piper should be used in the version 5.800 release with caution. While for the general application of transient wells the change to using pseudo pressure should produce more accurate results, in cases where transient wells were being used to approximate a particular profile, the resultant profile in version 5.800 will have changed from what was calculated in previous versions.

Terminology

Cum Gas-to-Date

This is the cumulative production from the pool up to the forecast start date. When the Cum Gas to Date is subtracted from the Original Gas-In-Place, the remaining gas-in-place is obtained and current shut-in reservoir pressure can be obtained for use in the deliverability calculations.

Sandface C

The equation governing the Inflow Performance Relationship is known as the Rawlins-Schellardt back pressure equation. It is a relationship that can be applied to all gas wells and is independent of reservoir drive. It is generally derived from AOF or Inflow performance testing.

$$q = C \cdot (P_R^2 - P_f^2)^n$$

Where:

q = C x (PR2- Pf2)n
q – flow rate, MMscfd or m3
C – constant, MMscfd/(psi2)n or (m3/kPa2)n

n – turbulence of flow, dimensionless
PR – reservoir pressure, psia or kPaa
Pf – flowing pressure, psia or kPaa

There are no limits on the range of the allowed value of the constant "C" due to the complicated interaction between C, AOF, n and pressure. Be aware however, that systems can be sensitive to changes in "C" and that extreme values of "C" can result in extremely large deliverability potentials which can cause system instabilities.

Sandface n

The inverse slope on the back pressure plot, "1/n", describes the turbulence of the flow rate. An "n" value equal to 1 describes the laminar flow (no turbulence) and an "n" equal to 0.5 describes a fully turbulent flow. This value is dependent on the location of measurement. Values for "n" are valid only between 0.5 and 1.0

Input values less than 0.5 are automatically defaulted to 0.5 upon choosing OK to close the Well Deliverability Editor. Similarly, values greater than 1.0 are automatically defaulted to 1.0.

Initial Reservoir Pressure

The initial pressure measured at the mean Pool Depth. It is the starting point for the pool material balance calculation. This pressure, minus depletion caused by produced gas, equals the remaining reservoir pressure which is used in the deliverability calculations.

UNITS: psia (kPaA)

DEFAULT: 0

Original Gas-In-Place (OGIP)

This is the original volume of raw gas contained in the pool. When the Cumulative Gas-to-Date (raw) is subtracted from this number, the remaining gas-in-place is obtained. The Original-Gas-in-Place is obtained from volumetric (geological) calculations or pressure/production information.

Reservoir Depth

The depth from the wellhead to the pool datum. In gas reservoirs, because the reservoir hydrostatic pressure variation is negligible, the Pool Depth can be taken to be the average of the Mid-Point of Perfs of all the wells in that pool.

Note that Piper requires that e either the Pool Depth or the Mid-Point of Perfs must be entered. Also note that the Pool Depth and the Mid-Point of Perfs will default to one another if only one of the two values is entered.

Reservoir Remarks

This field allows for the entry of pool specific remarks. Remarks are shown on the gathering system map if selected for display.

UNITS: None

DEFAULT: None

Reservoir Temperature

The Reservoir Temperature is the average reservoir temperature. This value is not critical to the calculations. It affects the "Z-factor" calculations in the material balance equation. If wellbore calculations are being performed, then the Reservoir Temperature is used in calculating the temperature gradient in the wellbore.

Recovery Factor

The Recovery Factor specifies the percentage of recoverable reserves. The Recovery Factor should be used for a non-linear reservoir model such as the Connected Reservoir model or the Water Drive model. In these cases, the models may not properly account for late-time depletion effects. A Recovery Factor can be used to eliminate the possibility of over-predicting the late time gas production of such a reservoir.

Reservoir Pressure

This is the average pressure encountered in a reservoir. This is a function of the hydrocarbon fluid, water and rock properties in the reservoir. A higher reservoir pressure tends to increase the deliverability of a well.

Surface Loss

Surface loss in the case of the pool refers to the percentage of production is lost. This may be by venting, leaks, fuel gas or by a number of other means.

Gas Composition

The Gas Composition editor allows you to enter Gas Gravity, Acid Gases (CO2, H2S) and Inert Gases (N2) concentrations on a pool wide basis. If these items are omitted the program uses the Default Gas Properties.

However, if you select gas composition tracking (under Options main menu, Forecast sub menu), you can input a detailed pool composition.

Gas Gravity

Gas Gravity is the molar mass (molecular weight) of the natural gas divided by the molar mass of air (28.94). It ranges from 0.55 for dry sweet gas to approximately 1.5 for wet, sour gas. The Gas Gravity is readily obtained from any laboratory gas analysis.

In Piper, Gas Gravity affects three variables namely super-compressibility (Z-factor), gas viscosity, and gas density.

The effects on super-compressibility and viscosity are not very significant. However, the effect on density is significant in two ways. It affects the friction pressure drop to some extent, but it affects the hydrostatic pressure drop directly - i.e. doubling the Gas Gravity doubles the density and therefore doubles the hydrostatic pressure drop. Thus Gas Gravity affects calculations in vertical pipe segments far more than in horizontal segments. This becomes significant if wellbores are modeled under the Advanced option.

UNITS: None

DEFAULT: 0.65

Carbon Dioxide (CO2)

Concentration of Carbon Dioxide in the gas stream. It has an effect on the calculation of "Z-factor". In addition, it is a component to be included when estimating Surface Loss.

UNITS: Percent (%)

DEFAULT: 0

- **Molecular weight**: 44.01 kg/kmol
- **Appearance:** colorless gas
- **Melting point**: -56.6°C

- **Boiling point**: -78°C
- **Gas Density**: 1.977 kg/m3

Hydrogen Sulfide (H2S)

Concentration of Hydrogen Sulfide in the gas stream. It has an effect on the calculation of "Z-factor". In addition, it is a component to be included when estimating the Surface Loss.

UNITS: Percent (%)

DEFAULT: 0

- **Molecular weight:** 34.08 kg/kmol
- **Appearance**: colorless gas
- **Melting point**: -85.6°C
- **Boiling point:** -60.3°C
- **Liquid Density:** 993 kg/m3
- **Gas Density**: 1.496 kg/m3

Nitrogen (N2)

Concentration of Nitrogen in the gas stream. It has an effect on the calculation of "Z-factor".

UNITS: Percent (%)

DEFAULT: 0s

- **Molecular weight:** 28.01 kg/kmol
- **Appearance:** colorless gas
- **Melting point:** -209.9°C
- **Boiling point:** -195.8 °C
- **Gas Density:** 1.250 kg/m3
- **Liquid Density:** 805 kg/m³

Methane (C1)

Concentration of methane in the gas stream. This is considered to be the main produced hydro-carbon in most cases

UNITS: Percent (%)

DEFAULT: 100%

- **Formula**: CH4
- **Molecular weight:** 16.04 kg/kmol
- **Appearance**: gas
- **Melting point:** -182.5 °C
- **Boiling point:** -161.5 °C
- **Gas Density:** 0.717 kg/m3
- **Liquid Density:** 425 kg/m³

Ethane (C2)

Concentration of ethane in the gas stream. It has an effect on the calculation of specific gravity.

UNITS: Percent (%)

DEFAULT: 0

- **Formula:** C2H6
- **Molecular weight:** 30.07 kg/kmol
- **Appearance:** gas
- **Melting point:** -183.3 °C
- **Boiling point**: -88.7 °C
- **Gas Density:** 1.357 kg/m3
- **Liquid Density:** 548 kg/m

Propane (C3)

Concentration of propane in the gas stream. It has an effect on the calculation of specific gravity.

UNITS: Percent (%)

DEFAULT: 0

- **Formula:** C3H8
- **Molecular weight:** 44.11 kg/kmol

- **Appearance:** gas
- **Melting point:** -189.9°C
- **Boiling point:** -42.2°C
- **Gas Density:** 1.858 kg/m3

Butane (C4 or nC4)

Concentration of butane in the gas stream. It has an effect on the calculation of specific gravity.

UNITS: Percent (%)

DEFAULT: 0

- **Formula:** C4H10
- **Molecular weight:** 58.14 kg/kmol
- **Appearance:** gas
- **Melting point:** -138°C
- **Boiling point**: -0.6°C
- **Gas Density**: 2.499 kg/m3

Isobutane (iC4)

Concentration of isobutane in the gas stream. It has an effect on the calculation of specific gravity.

UNITS: Percent (%)

DEFAULT: 0

- **Formula:** C4H10
- **Molecular weight:** 58.14 kg/kmol
- **Appearance:** gas
- **Boiling point:** -10.2°C
- **Gas Density:** 2.467 kg/m3

Pentane (C5 or nC5)

Concentration of pentane in the gas stream. It has an effect on the calculation of specific gravity.

UNITS: Percent (%)

DEFAULT: 0

- **Formula:** C5H12
  Molecular weight: 72.17 kg/kmol
  Appearance: liquid
  Melting point: -130°C
  Boiling point: 36°C
  Liquid Density: 626 kg/m³

Isopentane (iC5)

Concentration of isopentane in the gas stream. It has an effect on the calculation of specific gravity.

UNITS: Percent (%)

DEFAULT: 0

- **Formula:** C5H12
- **Molecular weight:** 72.17 kg/kmol
- **Appearance:** gas

Hexane (C6)

Concentration of hexane in the gas stream. It has an effect on the calculation of specific gravity.

UNITS: Percent (%)

DEFAULT: 0

- **Formula:** C6H14
- **Molecular weight:** 86.178 kg/kmol
- **Appearance:** liquid
- **Melting point:** -95.4 °C
- **Boiling point:** 68.7 °C
- **Gas Density:** 659 kg/m³

Heptane (C7++)

Concentration of hydrocarbons with a molar weight equal to or greater than heptane in the gas stream. It has an effect on the calculation of specific gravity.

UNITS: Percent (%)

DEFAULT: 0

- **Formula:** C7H16 (Heptane)
- **Molecular weight:** 100.23 kg/kmol
- **Appearance:** gas
- **Melting point:** -91°C
- **Boiling point:** 98°C
- **Liquid Density**: 684 kg/m³

Water (H2O)

Water is considered in several cases: static liquid columns, water influx into a reservoir, and liquid-gas ratios.

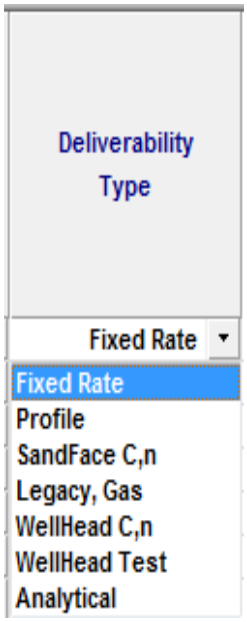
- **Molecular weight:** 18.02
- **Appearance:** colorless liquid
- **Melting point:** 0.0 °C
- **Boiling point:** 100.0 °C
- **Gas Density:** 0.600 kg/m3
- **Liquid Density:** 1000 kg/m³

Wellbores and Deliverability

The "deliverability" of a system is its capacity to deliver gas as a function of pressure. The maximum possible capacity is called the absolute open flow potential (AOF), and reflects what the system could deliver if there were no external losses acting on it; (i.e. if the flowing pressure was equal to zero).

There are several options available in Piper where you can enter well deliverability data, based on the type of gathered data. These are:

- Fixed Gas Rate
- Test Wellhead Flow Rate/Pressure
- Wellhead C and n
- Sandface C and n
- Transient Deliverability
- Profile Deliverability



The toggle buttons in the Well Deliverability editor are used to switch between the different options and highlight the necessary input cells (for any selected mode, the non-required cells are blued-out).

On-Stream Date

The date in which a well is to become active in the forecast interval set in the Forecast View tab. A well becomes active on the later of the on-stream date or the first date of the forecast interval.

Note: Although a well can have an on-stream date before the forecast period begins, Piper does not calculate the deliverability of the well for the period before the forecast interval. The well starts producing on the first forecast date if on-stream is set before the forecast date.

If the on-stream date is blank, a well is active the first forecast date.

UNITS: MM/DD/YYYY

DEFAULT: None

Fixed Rate Deliverability

General

This option represents a well that produces at a Fixed Gas Rate irrespective of pipeline, or reservoir pressures. The main purpose for this option is for tuning the system. The introduction of a fixed volume of gas simplifies the tuning process because with a fixed rate option a change in tuning parameters will only affect the flowing pressures in the system. This function is also a very useful option when a volume of gas is being brought into a gathering system but there is no reservoir or deliverability information available for it.

Fixed Rate Wells and Reservoirs

A Fixed Rate well can be connected to a reservoir. The reservoir will deplete, but the well performance will be independent of reservoir depletion.

However, a Fixed Rate well attached to a reservoir in Piper will shut-in. The criteria that determines whether a Fixed Rate well can flow is the static wellhead pressure. Piper will calculate the static wellhead pressure from the provided reservoir pressure and a static gas gradient from the reservoir to surface. If the line pressure exceeds the static wellhead pressure, the Fixed Rate well will be shut-in.

If there are a number of Fixed Rate wells in the model, Piper will shut-in wells with the lowest wellhead static pressure first. The ability of a Fixed Rate well to flow is thus independent of the downstream location of the well.

Profile Deliverability

A profile deliverability well behaves much like a fixed rate well. The rate specified for a profile well is independent of pressure. The difference between a profile well and a fixed rate well is that with a profile well the rate the well flows at is specified on a period-by-period basis.

When the profile well is selected in the Well Deliverability editor, you can either choose from existing profiles, or create a new profile. Note that the same profile can be assigned to more than one well.



Note that a rate entered in the first row corresponds to the rate in the first forecast period, and so on. If you want the well to begin producing at a later date, the rate data can be entered beginning at a higher row number. Blanks can be left in the prior rows.

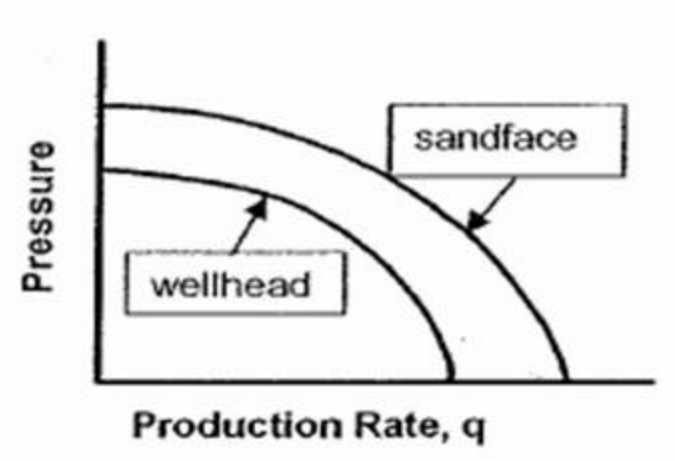
Background for Sandface and Wellhead Deliverability

In Piper deliverability can be defined in two locations:

- At the Sandface
- At the Wellhead

The Sandface Deliverability curve is sometimes referred to as the Inflow Performance Relationship (IPR). The Wellhead Deliverability Curve is sometimes referred to as the Outflow Performance Relationship (OPR). The difference between the Wellhead and the Sandface deliverability is due to the hydrostatic and frictional pressures losses of fluids flowing within the wellbore.

A typical Deliverability plot of both Sandface and Wellhead deliverability is shown below:



To define the deliverability at the wellhead, a 'Wellhead C,n' well should be chosen. To define deliverability at the sandface, a 'Sandface C,n' well should be chosen. Note that a 'Wellhead C,n' well will not take into account the effect of a wellbore, whereas a 'Sandface C,n' well will account for the effect of the wellbore.

Difference between Wellhead Test and Wellhead C,n Deliverability

The Wellhead Test Deliverability and Wellhead C,n Deliverability are identical in how they model deliverability. The different between the two is that the Wellhead Test deliverability will calculate the C value based on the current test rate and pressure that is entered, while the C, n Deliverability requires that the user enter the C, n values explicitly.

Using Turner or Coleman Correlation with Wellhead Deliverability Wells

Wellhead deliverability wells have, as their names suggests, their deliverability defined at the surface. Therefore, wellbore information is not required and is in general not used. An exception to this rule is when the Turner or Coleman critical liquid lift correlation is turned on and a wellbore has been defined.

In this case Piper will perform a check on the well, using the current well rate and pressure. The rate and pressure are extrapolated down to the end of tubing using the selected pressure loss correlation, and a comparison is made of the velocity of the gas at the end of tubing against the critical velocity required to lift liquids given the selected liquid lift correlation. If the velocity of the gas is less then critical velocity, Piper notify the user and shut the well in.

This provides users with a diagnostic to detect approximately when wells will load up without having to model those wells with the detail of the Sandface C,n or Transient deliverability model.

Note that the above steps are used strictly for determining the ability of a well to lift liquids at EOT, and that the wellbore is not used in any other of the wellhead calculations.

Wellhead Test Deliverability

General

This option allows you to enter a measured Wellhead flow rate and Wellhead flowing pressure from which Piper will calculate the deliverability for the well using the backpressure equation.

The backpressure equation is also governing known as the Rawlins-Schellardt backpressure equation. It is a universal relationship that applies to all gas wells and is independent of reservoir drive. It is generally derived from AOF or Inflow performance testing but can be estimated from current operating conditions if certain assumptions are made. For Wellhead Deliverability the for of the backpressure equation that is used is:

$$q = C \bullet (P_{ts}^2 - P_{tf}^2)^n$$

Note that there are two constants that define the deliverability of the well in the backpressure equation; the C and the n. For a Wellhead Test Deliverability the ‘n’ can be specified by the user if it is known or can be estimated. If the Wellhead 'n' is not specified, a default value of 1 will be assumed. A default value of 1 corresponds to very laminar flow, so little in the way of near-wellbore turbulent pressure losses, so it is most appropriate for aging wells or for low deliverability wells.

To perform the calculation of the C value, Piper will take the current reservoir pressure and adjust that pressure with a static gradient to come up with a corresponding static Wellhead Pressure. It will then use that static pressure, along with the current operating rate and pressure, to solve for C.

To use the Wellhead test option in **Piper** the well must have a reservoir associated with it in the Well Deliverability menu.

Wellhead Test Flow Rate

This is the raw gas flow rate, measured at the wellhead, at the Test Wellhead Flowing Pressure. The program uses these values to calculate the Wellhead "C" and "AOF".

UNITS: MMscfd ($10^3 m^3/d$)

DEFAULT: None

Wellhead Test Flowing Pressure

This is the flowing pressure measured at the wellhead, and corresponding to the Test Wellhead Flow Rate.

UNITS: psia (kPaa)

DEFAULT: None

Wellhead C,n Deliverability

General

This option allows the user to specify the Wellhead "c" and Wellhead "n" as determined from standard AOF/Back Pressure/Deliverability tests.

The equation governing the Inflow Performance Relationship is known as the Rawlins-Schellardt backpressure equation. It is a universal relationship that applies to all gas wells and is independent of reservoir drive. It is generally derived from AOF or Inflow performance testing. For Wellhead Deliverability the equation is stated as:

$$q = C \bullet (P_{ts}^2 - P_{tf}^2)^n$$

Where:

q = flow rate, MMscfd or $10^3 m^3/d$
C = constant, $MMscfd/(psi^2)^n$ or $(10^3 m^3/d/kPa^2)^n$
n = turbulence of flow, dimensionless
P_{ts} = static wellhead pressure, psi or kPaa
P_{tf} = flowing wellhead pressure, psi or kPaa

Wellhead, C

The “C” value for a well defines the magnitude of the wells rate response to changes in pressure. Larger C values will correspond to higher deliverability wells. A wellhead C value is sometimes available from a Welltest report. Alternatively, it can be calculated in the same way already described in the section Wellhead Test well Deliverability.

There are no limits on the range of allowed "C" values due to the complicated interaction between C, AOF, n and pressure. Be aware, however, that the system is very sensitive to changes in "C" and that extreme values of "C" can result in extremely large deliverability potentials which can cause system instabilities.

Wellhead, n

The ‘n’ value is a measure of the effect of turbulence in the near-wellbore region on the well’s performance. Values for "n" are valid only between 0.5 and 1.0. A default value of 1 corresponds to very laminar flow, so little in the way of near-wellbore turbulent pressure losses. A value approaching 0.5 would correspond to significant losses due to highly turbulent flow in the near-wellbore region.

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 that while in theory a value of n = 1 should not be possible, standard practice often prescribes an n value of 1 to aging or low deliverability wells that are expected to flow at a low rate.

If, in the Well Deliverability editor, the Wellhead 'n' is not specified, a default value of 1 will be assumed.

Input values less than 0.5 are automatically defaulted to 0.5 upon choosing OK to close the Well Deliverability Editor. Similarly, values greater than 1.0 are automatically defaulted to 1.0.

Transient Deliverability

This deliverability option models a well that produces from a single region or two-region composite reservoir of either finite or infinite dimension.

The distinct features of the Transient Deliverability well type are:

- The transient deliverability type will model the early time transient behavior (usually an initial flush production) by accounting for the period before boundary dominated flow is reached.
- Once a transient deliverability well ‘sees’ the boundaries of the reservoir, it behaves in much the same manner as a conventional C, n deliverability, with the productivity index for the well defined based on the well parameters that are defined (k, s, Ø, net pay, sw)
- The transient deliverability type models only single well pools. Therefore it does not account for effects of interference between wells in the same pool

The deliverability of a transient well is determined by the reservoir/deliverability parameters input in the Transient Well Editor. The Transient Reservoir and its impact on deliverability is discussed in detail in the section Transient Reservoir.

There are two solutions to the diffusivity equation which the transient well model uses to define its deliverability. One solution is for the flow period before the reservoir boundaries have been reached, and the other solution is for the flow period after the boundaries have been reached. At each flow period, the transient deliverability model determines whether the boundaries of the reservoir have been seen, and then applies the appropriate solution. For example, in the case of a single zone, finite radial model, the following analytical models would be used, depending on whether the well has seen the boundaries of the reservoir:

Transient (early-time) Flow:

$$m(p_{wf}) = m(p_i) - \frac{1637\,Q_g\,T}{kh}\left[\log\frac{kt}{\phi\mu c_{ti} r_w^2} - 3.23 + 0.87s\right]$$

For the late time, Boundary Dominated Flow:

$$Q_g = \frac{kh[m(\bar{p}_r) - m(P_{wf})]}{1422\,T\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]}$$

Transient Wells Associated with Wellbores

The transient deliverability model is a deliverability at the sandface and thus it can be associated with a wellbore. When a transient well is associated with a wellbore, pressure losses within the wellbore due to frictional and hydrostatic effects will be accounted for.

Multiphase flow losses can be modeled by specifying a LGR for the transient well and choosing an appropriate multi-phase correlation. Piper will solve to a converged solution that will match the surface conditions to the bottomhole conditions taking into account the appropriate pressure loss in the wellbore.

Transient Wells that Consider Liquid Loading

The Turner or Coleman critical liquid lift correlations can be used with transient wells that have been associated with a wellbore. When the Turner or Coleman correlations have been turned on, the

transient well will be tested to determine whether the transient well has the ability to lift liquids.

See the section Liquid Loading wells for details on the loading options.

Analytical Models

Piper allows you to import RTA analytical models and forecast those models forward under the constraints of the gathering system. The analytical models provide better simulation of transient flow behavior then do the traditional steady state models such as the Sandface and Wellhead C and n models. This is an important consideration when dealing with the following situations:

- Modeling of early time “flush” production from new wells
- Predicting short-term back-out of existing wells when new wells are brought on-stream
- Investigating the short term versus long term impact of debottlenecking alternatives, such as adding compression or looping lines

Gap Production

At times the analytical model taken from Harmony Enterprise is going to be derived from production data that is not current. In such cases, a forecast run in Piper will need to fill in the gap between the historical production data used in the model, and the first forecast period in Piper.

The assumption that is made for such a gap period is that the well is flowing at a constant bottomhole flowing pressure over the gap period that is equal to the bottomhole flowing pressure of the last historical production period.

- In this scenario, the user should be aware of the following outputs in Piper:
- In the Production Plotting tab, the rate versus time plot will show the gap production as forecast production values beginning at the end of the historical production
- In the Production Plotting tab, the rate versus cumulative plot will show the gap production
- In the plot for the well, the gap production will be displayed
- To keep the displayed reservoir data consistent with the original Harmony Enterprise data, the OGIP and Cumulative Production data displayed in the Pools editor will reflect the historical production data from the Harmony Enterprise model only, and not any of the additional production from the gap period.

Note that if the start date of the Piper model is redefined back to the end of the historical production of the Harmony Enterprise model, no gap period will be considered in the forecast.

Oil Wells

Analytical oil models can be imported into Piper. The following analytical oil wells are available: vertical, fracture, horizontal, composite, SRV (uniform fracs), multifrac composite
enhanced frac region, and general mutlifrac.

Corrected Pseudo-time

Harmony Enterprise allows you to create an analytical model either using or disregarding corrected pseudo-time. When a model is imported into Piper, the corrected pseudo-time setting is conserved from the RTA file. There is no toggle in Piper to toggle corrected pseudo-time from the setting of the imported file.

In the case where a new analytical model well is added in Piper manually through the editors, that well will use the default setting of using corrected pseudo-time.

RTA UID

The UID that is used in a RTA model is a fixed and unchangeable identifier of a well. Because the intent of the UID in Harmony Enterprise is to provide a unique name for the well, it's use in Piper is worth understanding.

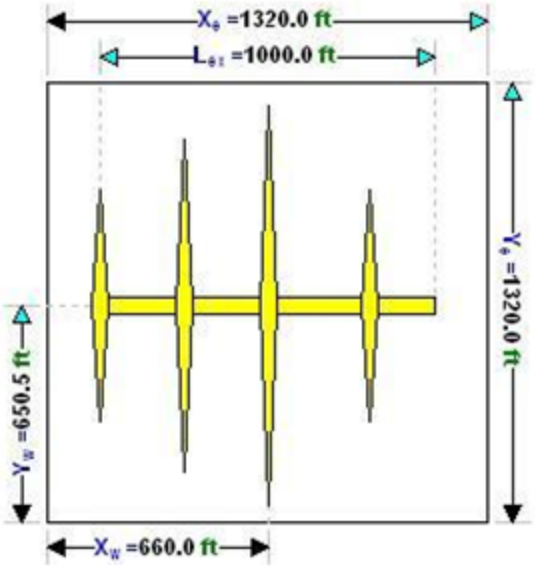
Upon import of an analytical model into Piper, the UID for a well in Harmony Enterprise becomes the well name for the well in Piper. The well name for the well in RTA becomes the alias name in Piper. This linkage between UID in RTA and Well Name in Piper insures that the well name in Piper is always unique and not duplicated within a single model import.

One of the constraints of Harmony Enterprise is that the Unique Identification (UID)of a well cannot be changed. This constraint has been carried over into Piper. After a model is imported from Harmony Enterprise, that well must remain with the same UID that it was imported. The UID is the identifier that internally ties the well to the production history that was used to create the analytical model. If the Well Name in Piper is changed from the imported UID, the production history of the analytical model will be ignored, and thus the performance of the well will not be the same as its performance in Harmony Enterprise. Users should therefore not change the well name of an imported RTA analytical model in Piper.

General Horizontal Multifrac Model

The general 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.

The reservoir dimensions and well position may be specified by the user, provided the entire well-bore 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.



To specify fracture locations, half-lengths and conductivity a table is provided with each row representing one fracture in the model. The fracture location is specified as a X_w in relation to the center point of the horizontal well: a negative location represents a fracture to the left of the horizontal well center and a positive location is to the right.

Layer Data

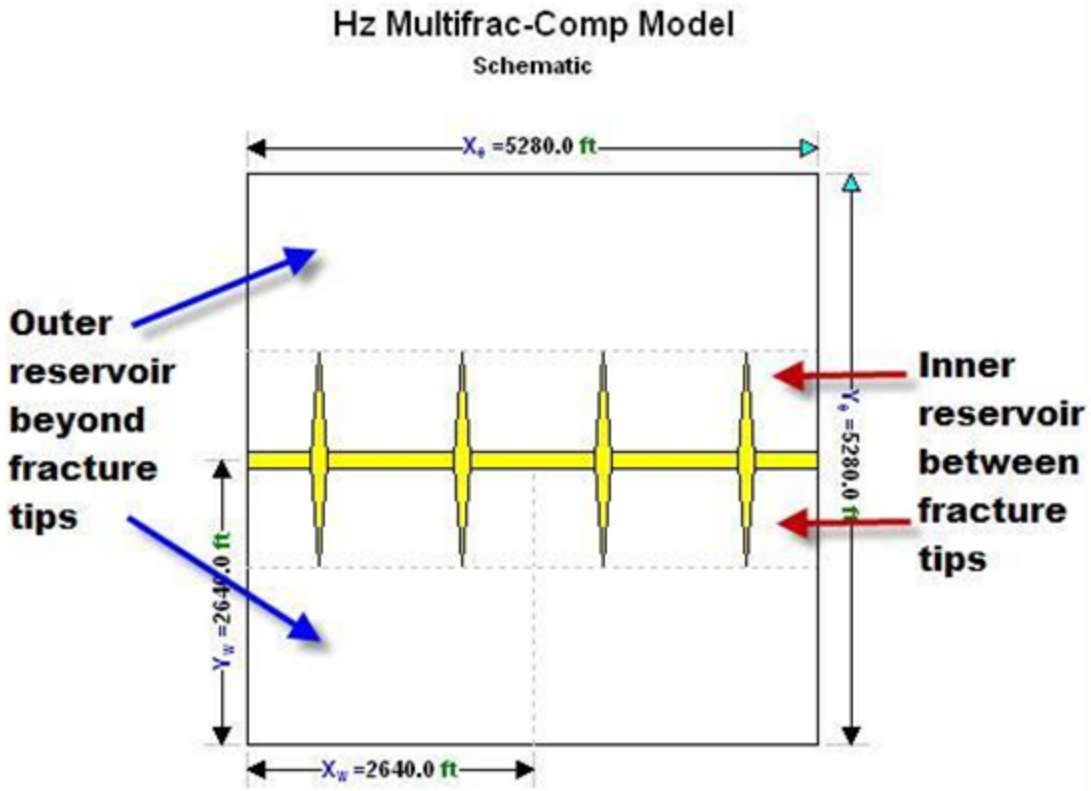
	ΔX_{WV}	$(x_f)_y$	F_{CD}
	ft	ft	
1	-500.0	660.0	1000.000
2	-250.0	1000.0	1000.000
3	0.0	1200.0	1000.000
4	333.0	600.0	1000.000

Damage skin is applied along the length of the horizontal wellbore and a turbulence factor may be specified.

Horizontal Multifrac

Composite Model

The horizontal multifrac composite model is a rectangular model that contains a non-contributing horizontal well fed by multiple identical and equally-spaced transverse fractures. The portion of the reservoir between the horizontal wellbore and the fracture tips is defined as the inner-reservoir and the rest is the outer-reservoir, as illustrated in the figure below. The permeabilities of the inner and outer regions can differ, making this model useful for modeling a stimulated reservoir volume (SRV) created by hydraulic fracturing which is fed by an unstimulated outer region.



This model calculates the reservoir's response from early-time storage and fracture flow, through the transition into boundary dominated flow. The fundamental building block of this model is the tri-linear fracture model for a vertical well. The outer-reservoir feeds the inner-reservoir via linear flow, the inner-reservoir feeds the fractures via linear flow, and the fluid within the fractures travels linearly towards the wellbore. However, for a horizontal well, the fluid within transverse vertical fractures actually has a radial flow pattern and a convergence skin has been implemented in order to account for this. As a result, it is not possible to observe radial flow with this model.

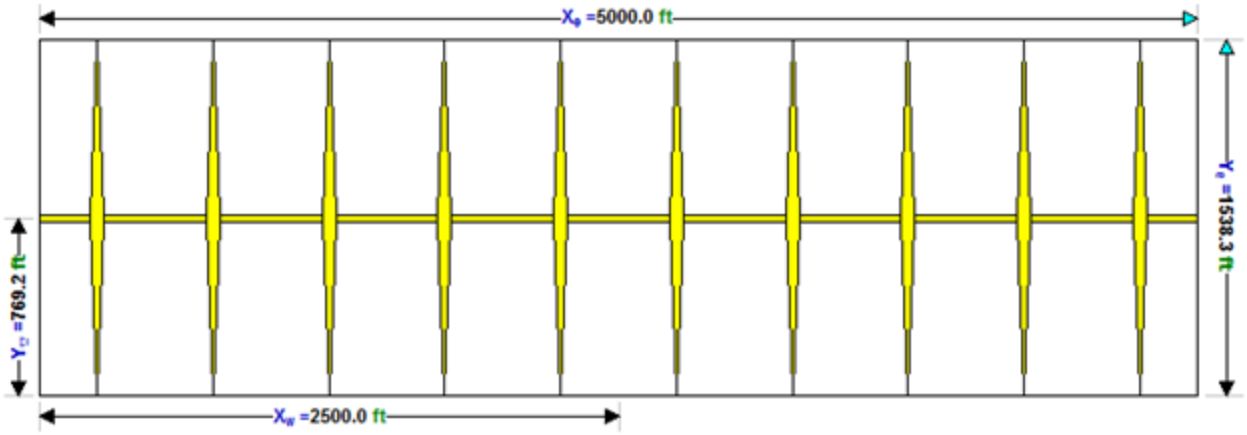
Note: A detailed description of the model is given by Brown et al. (2009)[1].

The reservoir dimensions, number of fractures and fracture half-length may be specified by the user, provided that the entire wellbore and all fractures fit within the reservoir boundaries. The dimensionless fracture conductivity must also be specified. A turbulence factor (D) can also be specified.

Horizontal Multifrac

SRV (Uniform Fracs) Model

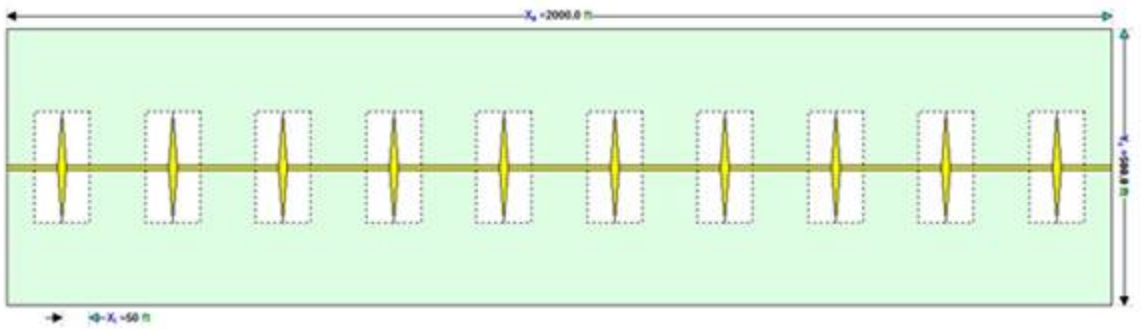
This model is the same as the horizontal multifrac composite model, but includes only the inner region of the reservoir—not the outer reservoir region. In this model, fracture tips always extend to the edge of the reservoir.



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 the distance from the fracture to the permeability boundary (X_I) can be specified by the user.



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)[2].

Analytical Model Parameters

Common Parameters

The following parameters appear in most or all analytical models

OGR	Oil-gas ratio
WGR	Water-gas ratio
p_i	Initial pressure
s	Skin (may be left blank)
h	Net pay
$_t$	Total porosity
S_g	Gas saturation
S_o	Oil saturation
S_w	Water saturation
c_f	Formation compressibility
X_e	Reservoir length
Y_e	Reservoir width
X_w	X position of well within reservoir
Y_w	Y position of well within reservoir (for horizontal well this is the middle of the horizontal length)

Z_w	Z position of the well within the reservoir net pay
r_w	Wellbore radius
D	Turbulence factor (may be left blank)
C_D	Storage coefficient (may be left blank)
OGIP	Original gas in place
$OGIP_F$	Original free gas in place
$OGIP_A$	Original adsorbed gas in place
A	Area, extent of reservoir

Model Specific Parameters

The following parameters are found in specific models. Models listed in right column

k	Permeability (all directions assumed to be the same)	Vertical, Fracture, Composite, Hz Multifrac Uniform
x_f	Fracture half-length	Fracture
$(x_f)_y$	Fracture half-length in y-direction	All Hz Multifrac models
F_{CD}	Fracture conductivity	All Hz Multifrac models
L_e	Effective horizontal well length	Horizontal
L_{ex}	Effective horizontal well length in x-direction	All Hz Multifrac models
k_x	Permeability in x-direction	Horizontal, Hz Multifrac
k_y	Permeability in y-direction	Horizontal, Hz Multifrac
k_z	Permeability in z-direction	Horizontal, Hz Multifrac
k_y/k_x	Ratio of y-direction to x-direction permeability	Horizontal, Hz Multifrac
k_z/k_x	Ratio of z-direction to x-direction permeability	Horizontal, Hz Multifrac
Perm ratios	Selecting this option allows the user to specify ratio values in place of k_y and k_z	Horizontal, Hz Multifrac
k1	Inner zone permeability	Hz Multifrac Composite, Hz Multifrac ERF
k2	Outer zone permeability	Hz Multifrac Composite, Hz Multifrac ERF
n_f	Number of fractures	All Hz Multifrac models
X_I	Distance from fracture to permeability boundary	Hz Multifrac ERF
r	Region radius	Composite

$OGIP_{SRV}$	Original gas in place in stimulated reservoir volume	Hz Multifrac ERF
A_{SRV}	Area of stimulated reservoir volume	Hz Multifrac ERF

1. Brown, M., Ozkan, E., Raghavan, R. and Kazemi, H. "Practical Solutions for Pressure Transient Responses of Fractured Horizontal Wells in Unconventional Reservoirs. SPE Paper 125043 prepared for Presentation at the 2009 SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana. October 2009.

2. Stalgorova, E. and Mattar, L. "Practical Analytical Model to Simulate Production of Horizontal Wells with Branch Fractures. SPE Paper 162515 prepared for Presentation at the 2012 SPE Canadian Unconventional Resources Conference, Calgary, Alberta. October 2012.

Sandface C,n Deliverability

General

This deliverability option allows the user to specify the constants of the backpressure equation (also known as the Rawlins-Schellhardt equation), the Sandface "C" and the Sandface "n", to define the deliverability of the well at the sandface. The C and n value are generally determined from standard AOF/Back Pressure/Deliverability tests, but they can also be calculated/estimated from current operating conditions if some assumptions are made. This section will explain the various alternatives available to users.

When the Sandface Deliverability option is selected in the Well Deliverabilityeditor, the information that defines the deliverability for that well is entered in the Wellbore Tuning editor. The Wellbore Tuning editor is accessible from the "Wells" menu option or using the Wellbore Tuning icon  .

The Sandface C,n deliverability option uses the backpressure equation to define the wells deliverability. The backpressure equation is an empirically derived industry standard that applies to all gas wells, independent of reservoir drive. It is generally derived from AOF or Inflow performance testing. For Sandface Deliverability the backpressure equation is stated as:

$$q = C \cdot (P_R^2 - P_f^2)^n$$

Where:

q = flow rate, MMscfd or $10^3 m^3/d$
C = constant, $MMscfd/(psi^2)^n$ or $(10^3 m^3/d/kPa^2)^n$
n = turbulence of flow, dimensionless

P_R = reservoir pressure, psi or kPaa
P_f = bottomhole flowing pressure, psi or kPaa

Sandface, C

The “C” value defines the magnitude of the wells rate response to changes in pressure. There are no limits on the range of allowed "C" values. Be aware however, the system is very sensitive to changes in "C" and that extreme values of "C" can result in extremely large deliverability potentials which can cause system instabilities.

Sandface, n

The inverse slope on the backpressure plot, "n", 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 will be 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. While in theory a value of n = 1 should not be possible, standard practice often prescribes an n value of 1 to aging or low deliverability wells that are expected to flow at a low rate.

Another common rule of thumb for n when it is not known is as follows:

- <1 MMcfd use n = 1.0
- >5 MMcfd use n = 0.5
- 1-5 MMcfd use n = 1.0 - 0.5 (interpolation)

This rule of thumb is simply an estimate. Many assumptions are being implicitly made when you follow the rule for defining an unknown n value. The n value is a function of permeability, or wellbore radius, of skin in the near wellbore region, and other variables, so making an assumption based purely on well rate needs to be understood in this context. If possible it is always better to use an n derived from a well test, or even from analogy of similar performing wells from the same geological structure.

The n value cannot be less then 0.5 or greater then 1.0. Input values less than 0.5 are automatically defaulted to 0.5 upon choosing OK to close the Well Deliverability Editor. Similarly, values greater than 1.0 are automatically defaulted to 1.0.

Using Turner or Coleman Correlation with Sandface Deliverability Wells

When the Turner or Coleman critical liquid lift correlations are turned on and a Sandface well has been selected, Piper will test for liquid loading and, if it is determined that the well cannot lift liquids through some or all of the wellbore, a pressure drop due to the existence of liquids in the wellbore will be applied.

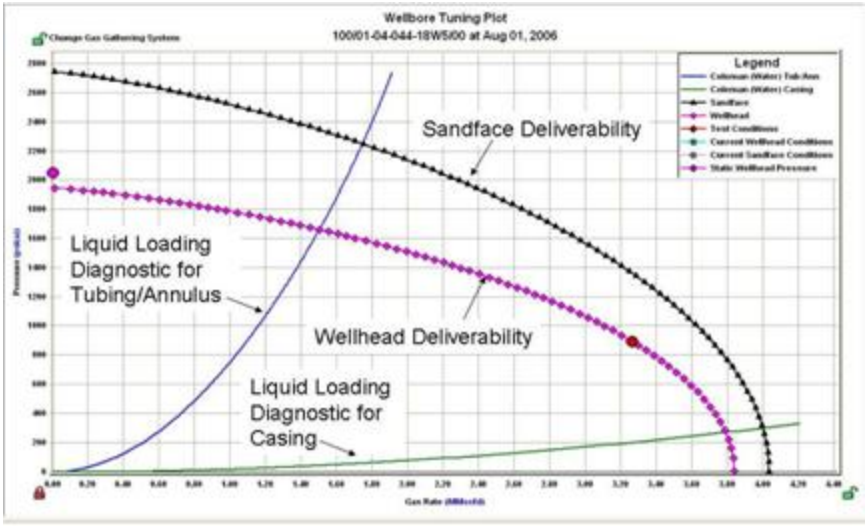
Wellbore Tuning Editor for Sandface Deliverability Wells

The wellbore tuning editor in Piper allows you to tune the deliverability of a well and customize the well performance to the specific conditions that are being experienced in the field. The intent of the wellbore tuning editor is to allow you to:

- Match well performance to existing conditions
- Model reduced production levels (known as meta stable production), from liquid loaded wells
- Forecast and estimate the impact of future liquid loading of a well
- Estimate Sandface C for free flowing wells and liquid loaded wells

Understanding the Curves Being Displayed in the Wellbore Tuning Plot

The Wellbore Tuning plot displays the deliverability curves for the well, in addition to a few diagnostic curves.



Sandface Deliverability Curve: The Sandface Deliverability curve is the black curve, and it displays the pressure response at bottomhole as a function of well rate. The curvature is defined as per the C and n values entered by the user, while the Y-intercept is defined by the current reservoir pressure (when the flow rate equals zero).

Wellhead Deliverability Curve: The Wellhead Deliverability curve is the pink curve. The wellhead deliverability curve displays the pressure response at the wellhead as a function of well rate. The wellhead deliverability curve is determined from the sandface deliverability curve and the pressure losses in the wellbore. For any given rate, the Wellhead pressure can be defined as the Sandface pressure at that rate minus the pressure losses in the wellbore.

Liquid Loading Diagnostic for Casing: The blue and green parabolic shaped curves are the Liquid Loading diagnostics. There are two diagnostic curves displayed, one green and one blue. The green curve is a diagnostic for the casing. For any given pressure (measured at MPP) the green curve reflects the minimum flow rate required to lift liquids at MPP. For flow rates and pressures to the left of the green curve, liquids cannot be lifted at MPP, while for flow rates and pressures to the right of the green curve, liquids can be lifted at MPP.

Liquid Loading Diagnostic for Tubing or Annulus: The blue curve is the diagnostic for the tubing or annulus. For any given pressure (measured at EOT) the blue curve reflects the minimum flow rate required to lift liquids at EOT and above. For flow rates and pressures to the left of the blue curve, liquids cannot be lifted at EOT and above, while for flow rates and pressures to the right of the blue curve, liquids can be lifted at EOT and above.

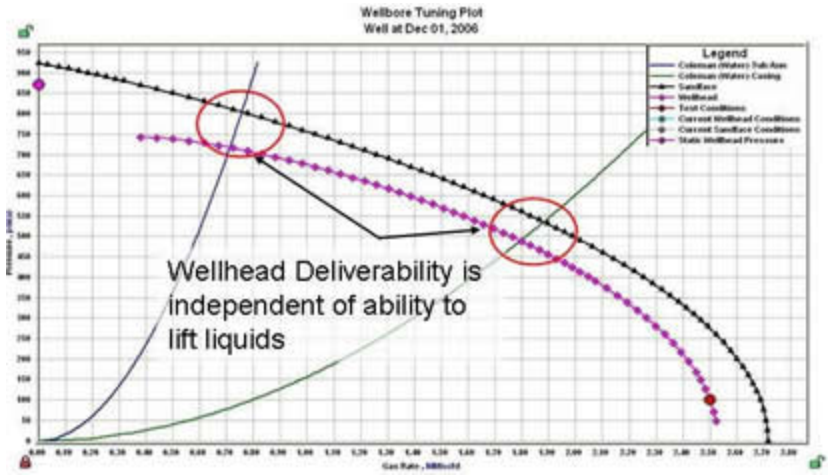
The separate diagnostics for the tubing/annulus segment and the casing segment is because the diameter of each segment of the wellbore is different, and thus the same flow rate through both segments results in different velocities for the gas. Generally the tubing/annular segment is a smaller diameter then the casing segment, and thus a well will first reach a point where liquids cannot be

lifted in the casing, followed at a later, lower rate by the point where liquids cannot be lifted in the tubing/annulus.

The user has the option to display either the Coleman or Turner diagnostic curves and to display either condensate or water as the primary fluid. The difference between choosing Coleman or Turner as your liquid lift diagnostic is explained in detail in the Turner and Coleman section.

Wellbore Tuning Plots when Liquid Lift is “Not Considered”

When the default Liquid Lift option is selected, liquid lift is “Not Considered” for the well. In this case Piper will not check to see if the well can or cannot lift liquids in the wellbore. The diagnostic curves may be drawn on the wellbore tuning plot, but will not be used internally by the program.



The result is that the Wellhead Deliverability curve is drawn throughout the range of pressures with the assumption that the single phase or multi-phase flow correlation being used is valid.

Wellbore Tuning Plot when a Liquid Lift Correlation is Selected

Description of Methodology

When the Turner or Coleman liquid lift correlation is turned on, Piper will take into account the ability of the wellbore to lift liquids. Piper will use the Turner or Coleman diagnostic to determine whether the gas rate is high enough at MPP and at EOT to carry liquids in the wellbore.

If the gas rate is not high enough at MPP to lift liquids in the casing, a pressure drop (specified in the “ΔP in Casing when Loaded” cell) will be applied to the casing to account for the existence of liquids in that segment of the wellbore (from MPP to EOT).

ΔP In Casing When Loaded
psi
20.0

The effect to the wellhead deliverability curve of adding the ΔP in the Casing is that the wellhead deliverability will undergo a step-change due to the extra pressure loss (see Figure below).

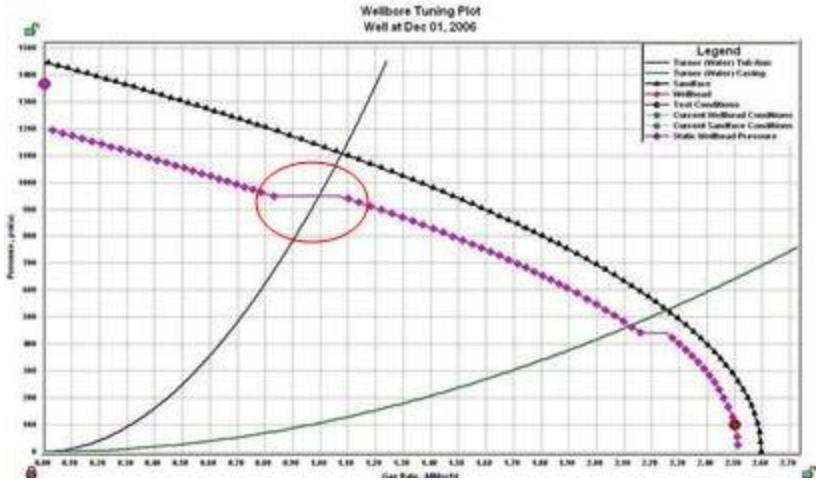


Note that the step change corresponds to where the Liquid Loading diagnostic curve for the casing (green) intersects the Sandface deliverability curve.

If the gas rate is not high enough at EOT to lift liquids in the tubing or annulus (depending on the flow path selected), a pressure drop (specified in the "ΔP in Tub/Ann when Loaded" cell) will be applied to the tubing or annulus to account for the existence of liquids in that segment of the wellbore (from EOT to surface).

ΔP In Tub/Ann When Loaded
psi
497.2

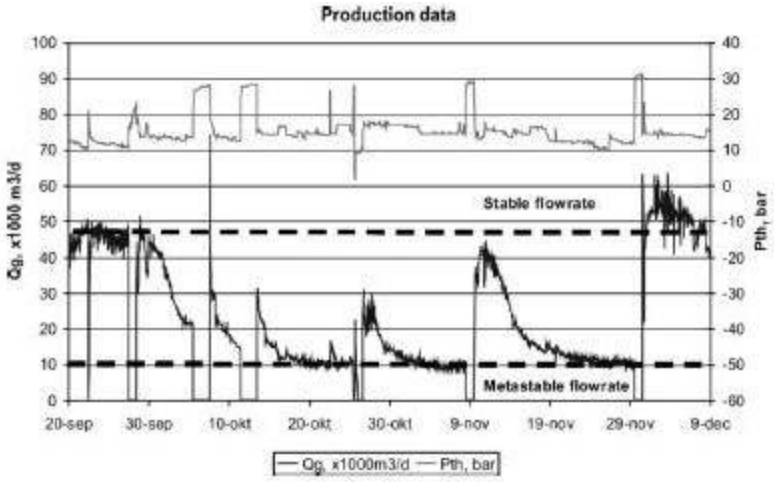
The effect to the wellhead deliverability curve of adding the ΔP in the Tubing or Annulus is that the wellhead deliverability will undergo a step-change due to the extra pressure loss (see Figure below).



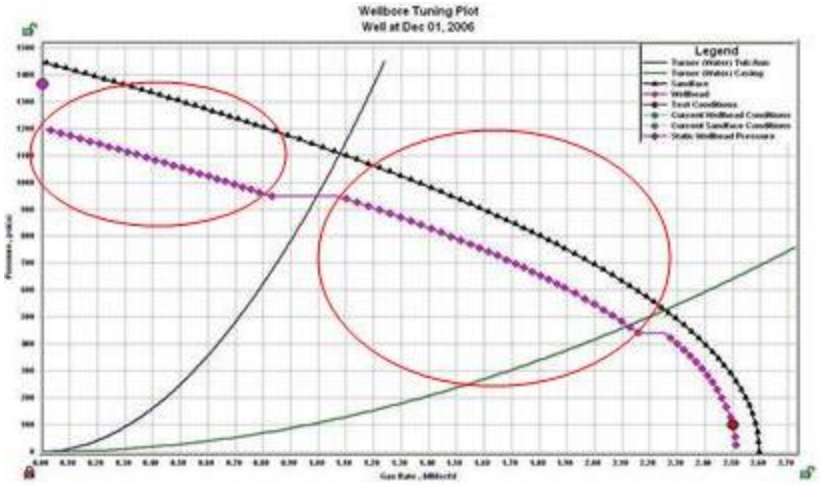
Note that the step change corresponds approximately to where the Liquid Loading diagnostic curve for the tubing/annulus (blue) intersects the Sandface deliverability curve. Note that the two curves will not intersect at the exact point because the diagnostic is being compared at EOT, so the comparison will be a little bit off of the intersection, which would be if the comparison was being done at MPP.

Modeling Wells that Produce at a Reduced Rate after Loading

A well that flows at a reduced rate due to a step change in wellhead deliverability that is brought on by the onset of loading (and thus an accumulation of liquids in the wellbore) is said to be flowing at a meta-stable flow rate. There is evidence that in practice many wells flow at a meta-stable rate after loading occurs.



The concept of a meta-stable flow rate is used by Piper to describe the flow rate that a well will flow at after passing the onset of liquid loading, and thus having liquids existing in the wellbore.



To illustrate the concept of a meta-stable flow rate, refer to the above figure. In the figure the well-head deliverability curve is exhibiting two steps changes, one that illustrates the effect of liquids accumulating in the casing segment, and one that illustrates the effect of liquids accumulating in the tubing/annulus segment.

The flow rates along the wellhead deliverability curve that is circled and is just to the left of where the well loads in the casing are meta-stable flow rates with the casing loaded.

Similarly, flow rates along the wellhead deliverability curve that is circled and is just to the left of where the well loads in the tubing/annulus are meta-stable flow rates with the tubing/annulus is loaded.

Modeling a Well that is Expected to Shut-in after Loading

Note that if a well is expected to shut-in after loading in the tubing/annulus, the pressure specified in the "ΔP in Tub/Ann when Loaded" can be adjusted to a high enough value that it overcomes the reservoir pressure, thus shutting in the well.

Modeling a Well that Produces Intermittently after Loading

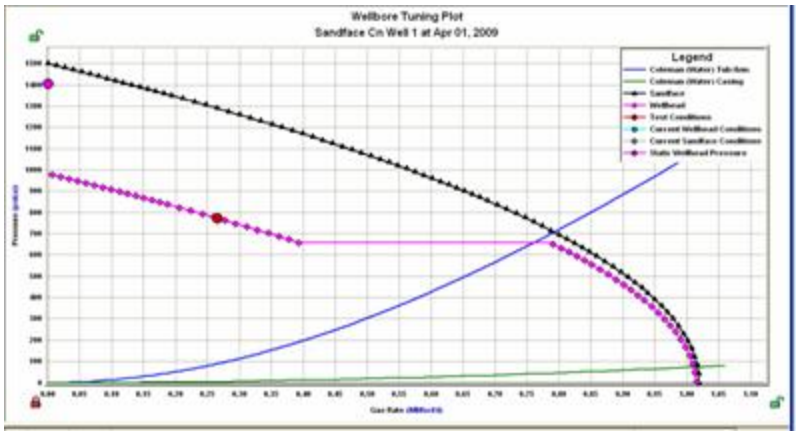
After loading with liquids, many wells begin to produce in an intermittent fashion. Sometimes the well is shut-in for periods of time to help 're-energize' the reservoir and blow out the liquids upon the commencement of flow. At other times, artificial lift techniques like plunger lift are used to unload the well, causing a fluctuating rate versus time behavior.

All of these scenarios describe situations where the well is undergoing a changing transient response over time. While the detailed, minute by minute response of the well is beyond the modeling scope of Piper, the concept a meta-stable flow rate can be applied to approximate the average behavior of such a well over a sufficient forecast period (the monthly forecast).

What needs to be determined is the average rate that the well would be expected to flow at after loading with liquids. For a well that has already loaded with liquids, this average rate is simply the current average production for that well. The current pressure is the average of the flowing pressure for that period.

To have the wellhead deliverability curve (pink) to align with the operating point, the pressure applied in the tubing/annulus segment, in other world the "ΔP in Tub/Ann when Loaded" cell, can be adjusted to match up with the operating point (note that this can also be done using the "Auto-Match" button).

The resultant Wellbore Tuning plot will look something like the following figure:



The current operating point is the red circle. Note that, as you would expect, the wellhead deliverability curve runs through the current operating point. The response of this model is that the well will flow at the reduced average rate for the current period. Because the flow rate for the well is a function of the wellhead pressure, that flow rate will change as the wellhead pressure is increased or decreased. If the pressure can be reduced to a pressure where the well can again lift liquids in the tubing/annulus segment, the well will flow at a higher rate as it will unload in the tubing/annulus.

Its important to note the assumptions that are being made with this deliverability model.

- What is essentially a transient response (be that plunger lift, manual shut-in, or natural reservoir shut-ins) is being approximated by the equivalent average pseudo-steady state response. If this transient response changes over time (the operating begins shutting in the well more frequently, the plunger lift cycle is extended or reduced), this will not be reflected in the model
- The rate versus pressure response of the well assumes that the effect of the liquids (as defined by the "ΔP in Tub/Ann when Loaded" that is specified) is independent of rate and pressure. The same ΔP is being applied to the tubing/annulus segment if the wellhead pressure goes up or down. This may only be an approximate assumption. For example, if this model is used on a well on plunger lift, the actual well response to increased tubing pressure would be a longer shut-in period, a

shorter flow period, in other words a number of variables that may not exactly align with the response of the model.

With these assumptions being considered, the model still provides a good, albeit rough, approximation of well behavior after the well begins to load with liquids.

Description of Inputs Liquid Loaded Wells

"ΔP when Tubing/Annulus is Loaded" Selection

The "ΔP in Tub/Ann when Loaded" cell is located towards the right hand side of the wellbore tuning editor.



The cell will be blue (not used in any calculations) when a Liquid Lift Correlation is "Not Considered".

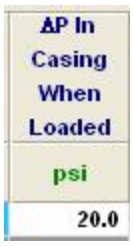
The cell will be white (considered in calculations and editable by the user) when a Liquid Lift Correlation is toggled on.

The value specified in the "ΔP in Tub/Ann when Loaded" represents the pressure loss that is going to be applied to the tubing or annulus (depending on the flow path selected) when the well can no longer lift liquids at the EOT.

Note that once a well can no longer lift liquids at EOT, the only pressure loss applied to that segment will be the "ΔP in Tub/Ann when Loaded". There is no consideration made for frictional or hydrostatic losses due to flow above the liquid column. This is done to keep the model simple, and because the actual height of the liquids is both unknown and often times fluctuating over time.

"ΔP when Casing is Loaded" Selection

The "ΔP in Casing when Loaded" cell is located towards the right hand side of the wellbore tuning editor.



The cell will be blue (not used in any calculations) when a Liquid Lift Correlation is “Not Considered”.

The cell will be white (considered in calculations and editable by the user) when a Liquid Lift Correlation is toggled on.

The value specified in the “ΔP in Casing when Loaded” represents the pressure loss that is going to be applied to the Casing segment (the flow path between EOT and MPP) when the well can no longer lift liquids at MPP.

Note that once a well can no longer lift liquids at MPP, the pressure loss specified in the “ΔP in Casing when Loaded” cell will be the only pressure loss applied to that segment. There is no consideration made for frictional or hydrostatic losses due to flow above the liquid column. This is done to keep the model simple, and because the actual height of the liquid column is both unknown and often times fluctuating over time.

ΔP Auto-Match

The “ΔP Auto-Match” is located on the right hand side of the Wellbore Tuning editor.



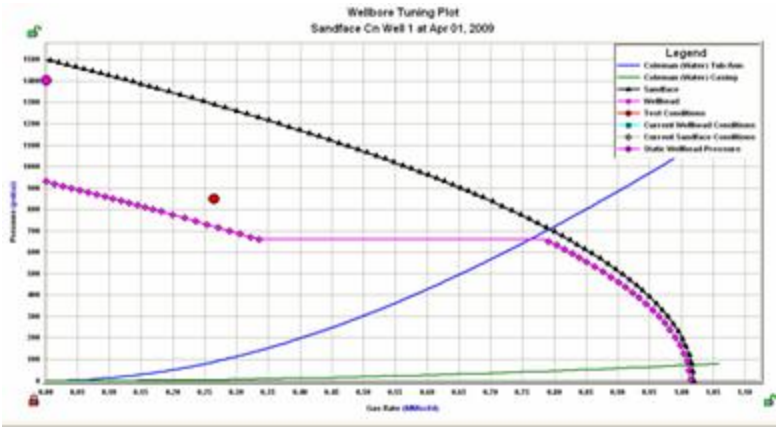
The auto-match is only used for wells that cannot lift liquids. The auto-match can be used to automatically align the wellhead deliverability curve with the current operating point. This is accomplished by adjusting either the “ΔP in Casing when Loaded” or “ΔP in Tub/Ann when Loaded” values. The former is adjusted when the well cannot lift liquids at MPP but can at EOT. The latter is adjusted when the well cannot lift liquids at either MPP or EOT.

If the well can lift liquids throughout the wellbore, pressing the “ΔP Auto-Match” will have no effect.

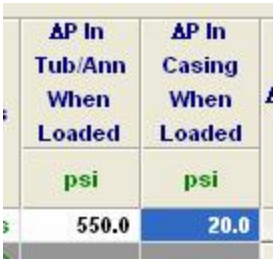
The “ΔP Auto-Match” should only be used when the “Advanced” option is selected for a well.

To demonstrate the effect of pressing the “ΔP Auto-Match”, consider the following case.

A well has its current operating point entered. A C,n value has been entered to define the deliverability. Initially, the operating point does not align with the wellhead deliverability curve.

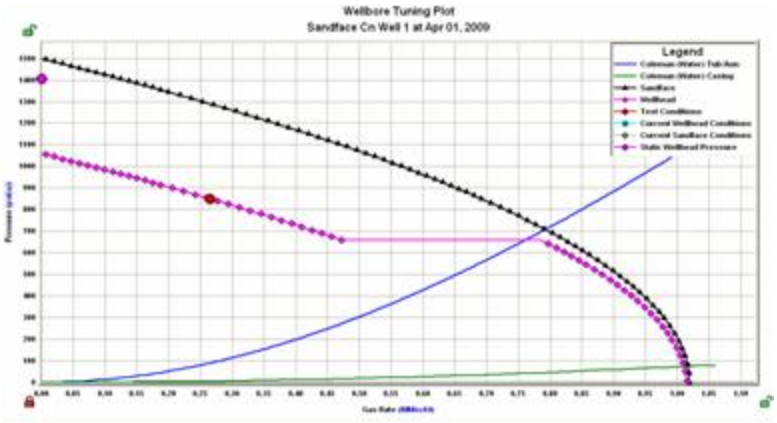


A default value has been applied by the program to the "ΔP in Tub/Ann when Loaded".

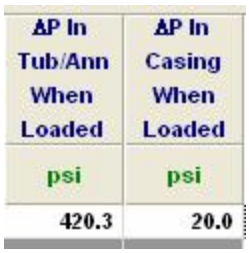


ΔP In Tub/Ann When Loaded	ΔP In Casing When Loaded
psi	psi
550.0	20.0

Once the "ΔP Auto-Match" Match button is pressed, the wellhead deliverability curve is aligned to fit the current operating point.



The value specified in the "ΔP in Tub/Ann when Loaded" cell is changed to reflect the pressure drop required to make the wellhead deliverability curve align with the operating point.



ΔP In Tub/Ann When Loaded	ΔP In Casing When Loaded
psi	psi
420.3	20.0

Liquid Level Reaches Tubing or Annulus

The “Liquid Level Reaches Tubing or Annulus” toggle allows the user to differentiate between wells where liquids will accumulate in the tubing or annulus and wells where the liquid level will not reach the tubing or annulus even if the well cannot lift liquids in the tubing/annular segment.



The specific situation that the “Liquid Level Reaches Tubing/Annulus” option is designed to account for is the situation where the tubing of the well is landed well above the perforations. If the tubing is well above MPP it is possible that liquids will accumulate in the wellbore to a level that is below the end of tubing, in which case even if the well cannot lift liquids above EOT, there is no additional liquids that accumulate.

The following criteria define the well performance after the tubing or annulus can no longer lift liquids:

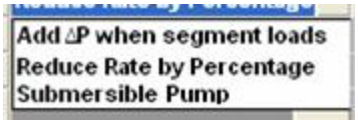
- When the Liquid Level If the “Liquid Level Reaches Tubing/Annulus” check box is toggled, the pressure drop specified in the “ΔP in Tub/Ann when Loaded” cell will be applied to the wellbore Tubing/Annulus segment.
- If the “Liquid Level Reaches Tubing/Annulus” check box is not toggled, single phase flow will be assumed in the Tubing/Annulus segment.

Description of Methods that can be Used to Model Behavior when Well Loads (Method Used when Well Loads column)

The “Method Used when Well Loads” options are available (in white) after a Liquids Lift Correlation has been selected, and thus when liquid loading is considered for the well. If the Liquid Lift Correlation is not considered, the cell will remain blue and not be used in any calculations.

There are 3 options that can be selected from when a well loads with liquids. These options are:

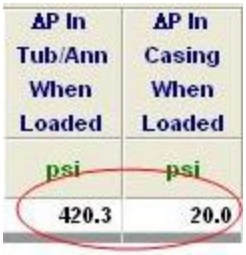
- Add ΔP when Segment Loads
- Reduce Rate by Percentage
- Submersible Pump



Each method will treat the well somewhat differently once the well cannot lift liquids at MPP or EOT.

Add ΔP when Segment Loads

With the "ΔP when Segment Loads" option, both the "ΔP in Tub/Ann when Loaded" and the "ΔP in Casing when Loaded" cells will be available and used in the calculations.

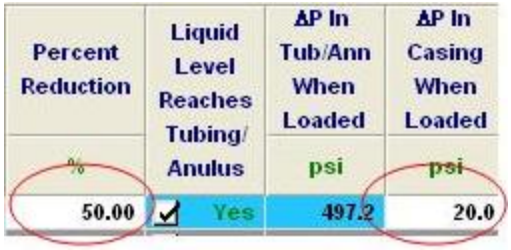


When the "ΔP when Segment Loads" option is selected, the following criteria will apply:

- When the well cannot lift liquids at MPP (as determined by the selected Liquid Lift Correlation), the pressure drop specified in the "ΔP in Casing when Loaded" cell will be applied to the wellbore casing segment.
- When the well cannot lift liquids at EOT (as determined by the selected Liquid Lift Correlation), the criteria depends on whether the "Liquid Level Reaches Tubing/Annulus" option is toggled on or off.
    - If the "Liquid Level Reaches Tubing/Annulus" check box is toggled, the pressure drop specified in the "ΔP in Tub/Ann when Loaded" cell will be applied to the wellbore Tubing/Annulus segment.
    - If the "Liquid Level Reaches Tubing/Annulus" check box is not toggled, single phase flow will be assumed in the Tubing/Annulus segment.

Reduce Rate by Percentage

With the "Reduce Rate by Percentage" option, only the "ΔP in Casing when Loaded" cell is available and editable. An additional cell, in the "Percent Reduction in Rate" column, is editable.



Percent Reduction	Liquid Level Reaches Tubing/ Anulus	ΔP In Tub/Ann When Loaded	ΔP In Casing When Loaded
%		psi	psi
50.00	☑ Yes	497.2	20.0

The following criteria will be applied when the “Reduce Rate by Percentage” option is chosen:

- When the well cannot lift liquids at MPP (as determined by the selected Liquid Lift Correlation), the pressure drop specified in the “ΔP in Casing when Loaded” cell will be applied to the wellbore casing segment.
- When the well cannot lift liquids at EOT (as determined by the selected Liquid Lift Correlation), the well rate at the onset of loading is reduced by the percentage specified.

Note that for this option, a value will be populated in the blue cell “ΔP in Tub/Ann when Loaded”. This value is not editable. It is calculated by Piper and is the pressure drop that must be applied to the tubing to satisfy the percent rate reduction that has been specified. Internally Piper is using this value to come up with the rate reduction that is anticipated.

Submersible Pump

With the “Submersible Pump” option, the “Fluid Column Height”, “Fluid Column GLG” and the “ΔP in Casing when Loaded” cells are available and editable.

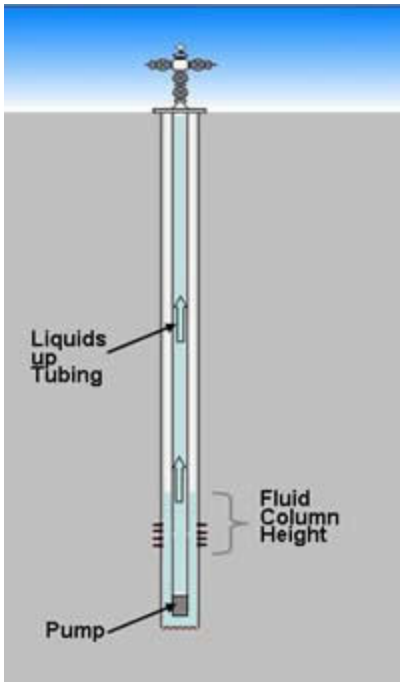


Fluid Column Height	Fluid Column GLG	Percent Reduction	Liquid Level Reaches Tubing/ Anulus	ΔP In Tub/Ann When Loaded	ΔP In Casing When Loaded
ft	psi/ft	%		psi	psi
500	0.265	50.00	☑ Yes	420.3	20.0

The following criteria will be applied when the “Submersible Pump” option is chosen:

- When the well cannot lift liquids at MPP (as determined by the selected Liquid Lift Correlation), the pressure drop specified in the “ΔP in Casing when Loaded” cell will be applied to the wellbore casing segment.
- When the well cannot lift liquids at EOT (as determined by the selected Liquid Lift Correlation), a submersible pump will be assumed to be installed at EOT.
- Liquid flow is up the pump through the tubular side (see figure)
- Gas flows on the annular side (see figure)

- A liquid column of the gradient and height specified is applied. Note that the liquid column height is defined from MPP.
- Above the liquid column, in the annulus, single phase gas flow is assumed.



Submersible Pump

Determining Sandface C For Sandface Deliverability Wells

If current wellbore and flowing conditions for a well are known, the Sandface Deliverability of a well can be calculated. While not as reliable as a deliverability estimate from a welltest (where a number of flowing conditions, rather then a single condition, are used to calculate deliverability), the estimate can still be used to approximate how pressure versus rate response of the well over time.

The Sandface C button will initiate a calculation of Sandface Deliverability for the selected well. The Sandface C button is located in the upper left portion of the Wellbore Tuning plot.



Sandface C can be calculated using flowing pressures or using non-flowing pressures. For loaded wells, calculations of Sandface C using flowing pressures are unreliable and non-flowing pressures should be used when available.

Caution when using the Sandface C Button

When a well can lift liquids throughout the wellbore, the calculation of Sandface C using flowing pressures can be quite reliable. When the well cannot lift liquids within the wellbore the calculation of Sandface C becomes less reliable if flowing pressures are used to calculate the current bottomhole pressure.

If a well cannot lift liquids in the casing segment (at MPP) usually the calculation of Sandface C using flowing pressure is usually still reasonably reflective of the actual well behavior. This is because generally the tubing is landed close to MPP, and thus the accumulation of liquids in the casing results in a minimal pressure drop.

On the other hand, the calculation of Sandface C using flowing pressures for a well that has liquids accumulating in the tubing is much less relaible. The uncertainty about the height of the liquid column can lead to large errors.

Calculating Sandface C using flowing pressures for a well that cannot lift liquids in the tubing/annulus segment should be recognized as only an **estimate** of Sandface Deliverability and should be interpreted as such. When a well cannot lift liquids in the tubing it is preferable to either calculate Sandface C from non-flowing pressure data, or to

Inputs for the Calculation of Sandface C

Before Piper can calculate the value of Sandface C for a well, the user must input a number of parameters defining both the current well performance as well as the wellbore.

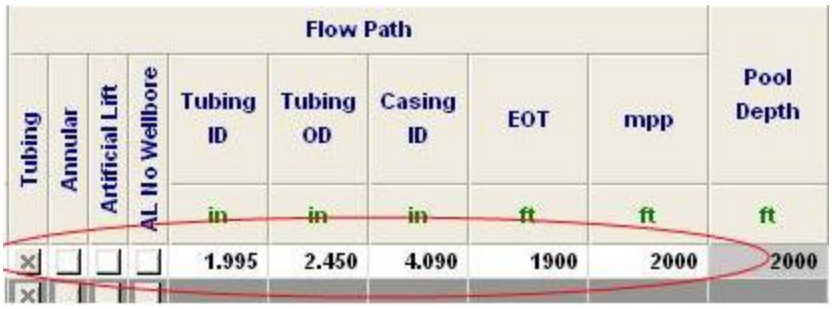
The minimum inputs that need to be defined by the user are:

- **A Surface Test Conditions: as defined by the Surface Test Rate, Surface Test Pressure (Tubing and/or Casing) and LGR**

Surface Test			Sandface			
Rate	Tubing Pressure	Casing Pressure	IIFS Pr Used	C	n	LGR
MMscfd	psi(a)	psi(a)		MMscfd/(psi²)ⁿ		bbl/MMscf
1.000	175.0	250.0		4.53e-07		1.0

Note that if flowing pressure is going to be used to calculate Sandface C, only the flowing pressure (either tubing or casing) needs to be specified. If non-flowing pressure is going to be used, both tubing and casing pressure needs to be specified.

- **Wellbore and Flow Path**



Note that if the MPP is not specified, it will be assumed to be the same as the pool depth. If the EOT is not specified it will be assumed to be the same as MPP.

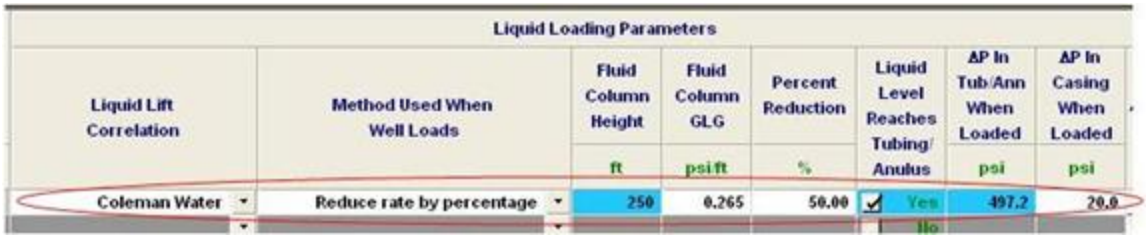
- **Pressure Loss Correlation**



The Multi-phase flow option is selected if liquids exist in the well. If Beggs and Brill is used, the distributed flow option can be toggled if the user wants to "force" the distributed flow regime in the wellbore.

If the user wants to consider the ability of the well to lift liquids, these options can be accessed under "Liquid Loading Parameters"

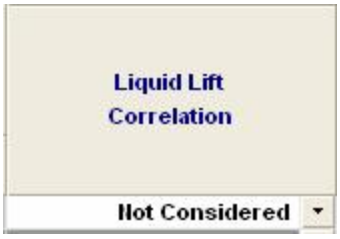
- **Status of Turner and Coleman critical liquid lift tests**



The Sandface C Calculation

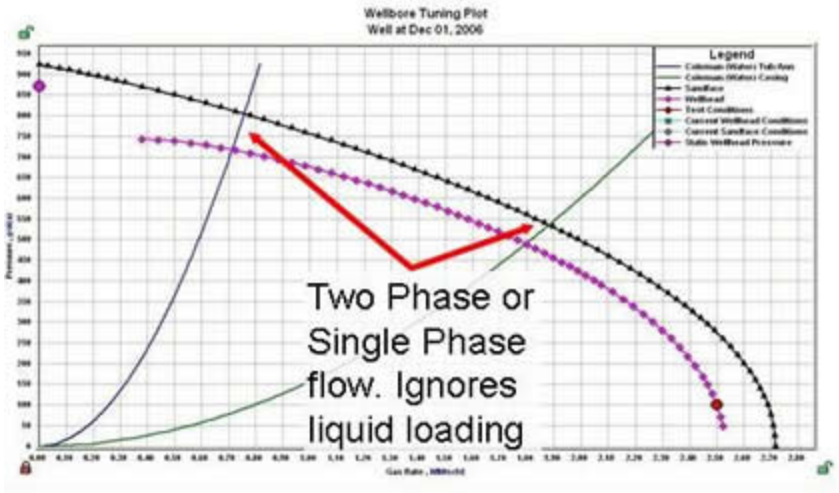
Calculation of Sandface C for Wells where Liquid Loading is not Considered:

If neither the Turner or Coleman critical liquid lift tests are selected, Piper will not take into consideration the ability of the well to lift liquids in its calculation of Sandface C.



Piper will assume that the gas can lift liquids throughout the wellbore. The single phase or multi-phase correlation will be applied to the length of the wellbore.

A value for Sandface C will be calculated based on the current flowing pressure, rate and LGR that have been entered as the Surface Test condition.



The above figure illustrates how the ability of the well to lift liquids is ignored. Note that to the left of the liquid loading diagnostic curves for the tubing/annulus and casing (blue and green curves) there has been no change to the wellhead deliverability curve.

Calculation of Sandface C Using Non-Flowing Pressure for Wells that Consider Liquid Loading

Piper can estimate the Sandface Deliverability of a well that can no longer lift liquids by using the non-flowing pressure.

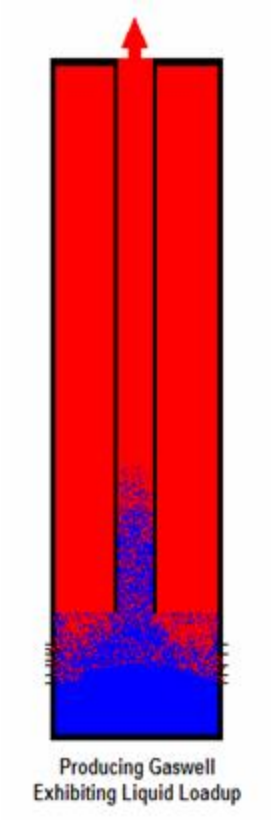
Note that non-flowing pressure can only be used when a well does not have a packer installed down-hole.

Theory Behind using Non-flowing Side Pressures to Calculate Well Deliverability

The application of non-flowing pressure to calculate Sandface C comes about because of the unreliability of using flowing side pressures for wells that cannot lift liquids in the tubing/annulus. The extent that liquids accumulate in the tubing/annulus is an unknown, and therefore using flowing side surface pressures to estimate bottomhole conditions is unreliable. On the other hand, with non-flowing side pressures, a much more reliable bottomhole pressure estimate can be attained.

The theory behind using non-flowing pressures to calculate Sandface C is based on the distribution of liquids in a wellbore once a well can no longer lift liquids to surface.

Consider the scenario where a well can no longer lift liquids to surface either in the casing or the tubing. Liquids will accumulate in the wellbore in both segments of the wellbore (see figure below).

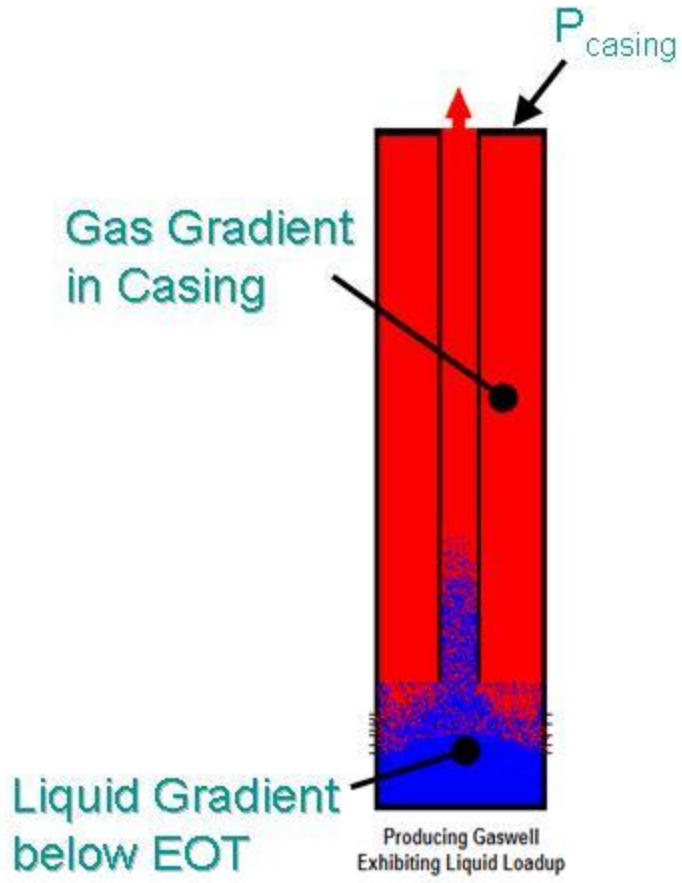


Note how the liquids accumulate on the flowing side of the wellbore (in this case in the tubing), but not on the non-flowing side (annular side).

Because liquids do not accumulate along the non-flowing side, the only pressure drop across that side is due to the presence of the gas. The calculation of the pressure drop from surface to EOT due to the hydrostatic column of gas is a reliable one.

For most wells, the end of tubing is landed within a short distance of MPP. Thus the pressure drop in the casing segment due to the liquids that have built up is generally small in relation to the reservoir pressure, and therefore an approximation of this pressure drop is usually sufficient. In Piper, by default the assumption will be made that the pressure loss in the casing due to liquids is equal to the length of the casing segment (the distance from MPP to EOT) multiplied by a gasified liquid gradient of 0.265 psi/ft.

The gradient of 0.265 psi/ft is an experienced based estimate of the effect of accumulated liquids in the wellbore. The overall effect of liquids on the casing segment can be modified by the user by changing the value of the "ΔP in Casing when Loaded" cell.



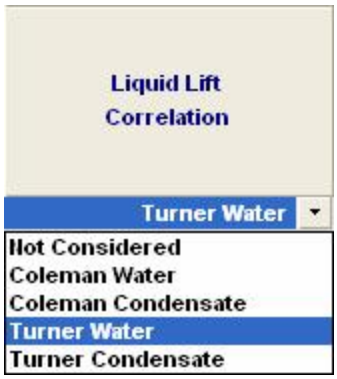
F.A..S.T Piper will thus calculate the pressure at the Sandface using a combination of the gas gradient down the non-flowing side, and an estimate of the pressure drop due to the liquids that have accumulated from EOT to MPP.

$$P_{wf} = P_{static} + \Delta P_{g\text{-}HH} + 0.265psi/ft*(MPP\text{-}EOT)$$

Once a pressure loss at the Sandface is calculated, it is a relatively simple calculation of C. In addition, Piper will calculate what the pressure drop due to accumulated liquids along the flowing side must be to satisfy the fact that the pressure and EOT is equal on both the flowing and non-flowing side. The calculated pressure drop on the flowing side is then input in to the ΔP in Tub/Ann when Loaded cell.

Input Requirements to Perform the Calculation of Sandface C using Non-flowing side Pressure

The calculation of Sandface using non-flowing side pressures can be performed whenever a Liquid Lift Correlation has been selected:



The use of non-flowing side pressures to calculate Sandface C requires that the “Use Non-Flowing Pressure Data” option be toggled.



Calculation of Sandface C Using Flowing Pressure for Wells that Consider Liquid Loading

As already noted, when the well cannot lift liquids within the wellbore the calculation of Sandface C using flowing pressure data becomes less reliable. This is due to the existence of accumulated liquids along the flowing side, and the lack of information available to accurately define the effect of those liquids on the overall wellbore pressure drop (in particular the liquid height is generally unknown, and the gradient can only be estimated).

It is important here to distinguish again between a well that cannot lift liquids in the casing, and one that cannot lift liquids in the tubing. If a well cannot lift liquids in the casing segment (at MPP) the

calculation of Sandface C using flowing pressure data usually still reasonably reflects the actual well behavior. This is because generally the tubing is landed close to MPP, and thus the accumulation of liquids in the casing segment of the wellbore has a minimal effect on the overall pressure drop.

On the other hand, the calculation of Sandface C using flowing pressures for a well that has liquids accumulating in the tubing is much less reliable. The uncertainty about the height of the liquid column can lead to large errors.

Piper provides the functionality to estimate a value of Sandface C from a loaded well while using flowing pressures. There are actually two estimates of C that Piper can make, and these two estimates can be considered to bound the range of possible solutions with the most optimistic deliverability possible, and the most pessimistic deliverability possible. While neither estimate will likely reflect the actual deliverability of the well, these estimates can be used, along with historical decline data, to come up with a C value that both forecast the well production forward so that it matches that historical decline, and that predicts an unloaded condition that matches the expected rate if the well was unloaded.

Optimistic Deliverability Estimate

The Optimistic Deliverability estimate is attained by setting the “Liquid Level Reaches Tubing/Annulus toggle to “Yes” before calculating Sandface C for the well.



Piper will assume that:

- If the wellhead pressure could be reduced 1psi, the well would unload in the tubing.

The most optimistic deliverability possible for a loaded well will occur if that well is just on the cusp of loading. The result of this optimistic estimate is the largest value of Sandface C (and therefore the largest AOF) possible for that well given its current flow rate and wellbore definition.

Pessimistic Deliverability Estimate

The Pessimistic Deliverability estimate is attained by setting the “Liquid Level Reaches Tubing/Annulus” toggle to “No” before calculating Sandface C for the well.



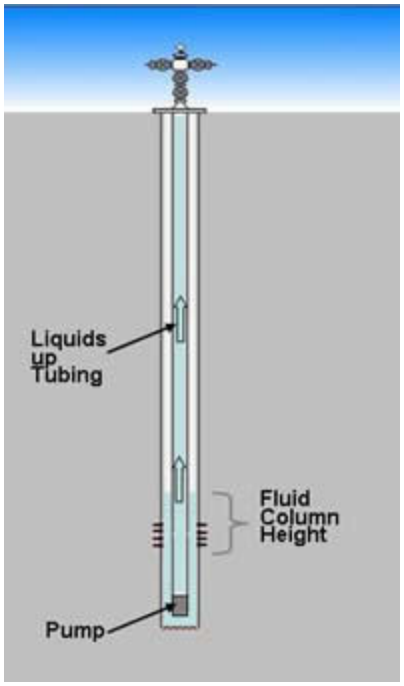
Piper will assume that:

- In the wells current state, while liquids cannot be lifted in the tubing/annulus there are no liquids that have accumulated in the tubing/annulus

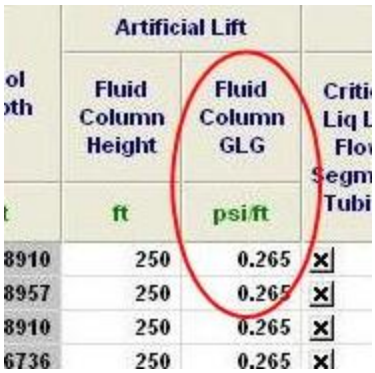
The most pessimistic deliverability possible for a loaded well will occur if, though loaded, liquids have not accumulated in the tubing of that well. The result of this pessimistic estimate is the smallest value of Sandface C (and therefore the smallest AOF) possible for that well given its current flow rate and wellbore definition.

Pumping Flow Path

Users have the option to specify that a well is currently pumping and therefore use artificial lift as the flow path. The artificial lift scenario that Piper will simulate is a submersible pump located at EOT. In such a scenario, the pump is assumed to produce the liquids up the tubing, while gas is produced up the annulus.



The fluid filling the Fluid Column Height in the annulus of the wellbore is assumed to be of a gradient equal to the Fluid Column GLG.



	Artificial Lift		
ol pth	Fluid Column Height	Fluid Column GLG	Criti Liq L Flo Segm Tubi
t	ft	psi/ft	
8910	250	0.265	☒
8957	250	0.265	☒
8910	250	0.265	☒
6736	250	0.265	☒

When artificial lift has been selected, Piper will calculate the pressure loss in the wellbore based on the assumption that liquids exist up to some level in the annulus, and that beyond that liquid level single phase gas flows.

$$\Delta P_{total} = \Delta P_{GLG} + \Delta P_{HH} + \Delta P_{Frictional}$$

Where:

ΔP_{GLG} = Pressure Loss due to liquid column in the annulus

ΔP_{HH} = Hydrostatic Pressure Loss of gas

$\Delta P_{Frictional}$ = Frictional Pressure Loss of gas

When EOT is above MPP then the pressure drop due to the liquid column in the annulus will include the height of the fluid column from MPP to EOT. When EOT is below MPP, then the pressure drop due to the liquid column in the annulus will use the height of the fluid column less the distance from end of tubing to the midpoint of perforations.

The gasified liquid gradient for all segments of the wellbore loaded with liquids is defined by the value of the Fluid Column GLG.

No Wellbore

No wellbore is a special case of artificial lift where the impact of the liquid column in the annulus and the frictional effect of gas traveling up the wellbore are ignored. Piper thus uses only a static gas gradient from the reservoir to surface.

No Wellbore is the default option for transient wells that have been imported from previous versions of Piper.

Turner and Coleman Critical Liquid Lift Correlations

When gas production is associated with water or condensate production, a minimum gas flow rate required to lift liquids has to be determined at a given flowing pressure, temperature and tubing diameter.

R. G. Turner, M. G. Hubbard and A. E Dukler first presented the Turner critical liquid lift correlation at the SPE Gas Technology Symposium held in Omaha, Nebraska, September 12 and 13, 1968. The correlation (SPE paper 2198) calculates the minimum gas flow rate required to lift liquids out of a wellbore and is often referred to as The Liquid Lift Equation or Critical Flow Rate Calculation for Lifting Liquids.

Steve B. Coleman, Hartley Clay, David McCurdy and Lee Norris published a series of papers dealing with the phenomena of liquid loading. The papers presented a modified version of the Turner correlation that appeared to agree more closely with real life liquid loading data.

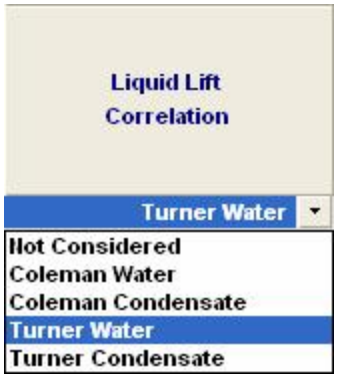
Piper uses the Turner and Coleman critical liquid lift correlations to determine when the onset of liquid loading in the wellbore will occur.

The Turner and Coleman diagnostic curves can be displayed in the wellbore tuning plot. Piper will display the curve for the Tubing / Annulus segment of the wellbore (the critical liquid lift calculation is performed at the end of tubing) and for the Casing segment (the critical liquid lift calculation is performed at the mid point of perforations).



The curves can be displayed for either water or condensate, whichever is the dominant fluid in the wellbore.

The Turner and Coleman critical liquid lift correlations need to be activated before they will be used to determine the state of loading in the wellbore. Activation occurs when water or condensate box is checked for either correlation.



Use of the Turner and Coleman Critical Liquid Lift correlation can be activated in 3 possible menus, depending on the type of well:

- **Wellbore Descriptions Menu:**activates correlation for Transient and Sandface wells
- **Wellbore Tuning Menu:**activates correlation for Sandface wells

Theory of Turner and Coleman Critical Liquid Lift Correlations

The Turner and Coleman correlations assume free flowing liquid in the wellbore form droplets suspended in the gas stream. Two forces act on these droplets. The first is the force of gravity pulling the droplets down and the second is drag force due to flowing gas pushing the droplets upward. If the velocity of the gas is sufficient, the drops are carried to surface. If not, they fall and accumulate in the wellbore.

The Turner correlation was developed from droplet theory. The theoretical calculations were then compared to field data and a 20% fudge factor was built-in. The correlation is generally very accurate and was formulated using easily obtained oilfield data. Consequently, it has been widely accepted in the petroleum industry. The model was verified to about 130 bbl/MMscf. The Turner correlation was formulated for free water production and free condensate production in the wellbore.

$$V_{g(water)} = \frac{5.62 * (67 - k * P)^{0.25}}{(k * P)^{0.50}}$$

$$V_{g(condensate)} = \frac{4.02 * (45 - k * P)^{0.25}}{(k * P)^{0.50}}$$

$$k = \frac{2.693 * G}{Z * T}$$

From the minimum gas velocity, the minimum gas flow rate required to lift free liquids can then be calculated using:

$$q_g = \frac{3.06 * P * v_g * A}{Z * T}$$

The Coleman correlation effectively removed the 20% factor that Turner had added to his correlation after finding that this provided better predictions for low pressure wells (less then 500psi). Apart from this, Coleman is using a methodology consistent with what Turner used.

How Equation of State affects Deliverability

All of the Piper well deliverability models are functional with the equation of state or equilibrium ratio model (either Peng-Robinson, Modified Wilson or Wilson).

When Peng-Robinson or one of the equilibrium ratio methods has been turned on, Piper will convert the gas and oil volumes defined by the deliverability relationship and OGR(or in the case of fixed rate and profile wells, the specified oil and gas rates) into an equivalent recombined molar rate. The molar rate is then flashed at the changing pressure and temperature conditions throughout the pipeline system in order to determine the gas and oil volumes.

Note that in the Wellbore Tuning plot and in deliverability plots, the gas rates shown are the recombined rate and do not reflect the actual in-situ gas rates flashed to by the equation of state or equilibrium ratio model.

Standard Rates and In-situ Rates

Both in-situ and standard rates can be displayed in the annotations of all nodes, wells and facilities, and in most facility plots.

In-situ Rates

In-situ rates are defined as the rate of each phase (gas, oil and water) present at the temperature and pressure of a given point in the system.

In black oil this means translating the standard condition volume of gas with the amount of gas in water (R_{sw}) and gas in oil (R_{so}) at the pipeline condition, and translating the volume of water in the gas (Water of condensation) at the pipeline condition.

For equation of state and equilibrium ratios this means the flashed oil and gas volumes at pipeline conditions.

It's important to make the distinction that in-situ rates are still converted in plots and annotations to their equivalent standard condition volume. This is done to be consistent with the common practice to always display gas rate in MMscfd.

Standard rates

Standard rates are defined as the rate of each phase (gas, oil and water) present at standard conditions.

In the same manner as for in-situ rates, for black oil standard rates are determined by translating volumes using R_{so}, $R_{sw}$and water of condensation. Likewise, for equation of state and equilibrium ratios, standard rates are determined by flashing the rates at standard conditions.

Terminology

Hydrostatic Pressure Loss

This refers to a pressure loss caused by the weight of a vertical column of fluid. The equation for this relation is:

$$\Delta P_H = H \rho g$$

$\Delta P_H =$ pressure loss due to hydrostatic head of fluid
$H =$ vertical distance
ρ = fluid density
g = acceleration due to gravity
UNITS: psia (kPa)
DEFAULT: None

Frictional Pressure Loss

This refers to the pressure drop in a length of pipe that is caused by frictional effects. The governing equation for friction loss is:

$$\Delta P_f = \frac{f \rho v^2 L}{2gD}$$

ΔP_f = pressure loss due to friction
f = Moody friction factor (Moody = 4x Fanning)
ρ = fluid density
v = velocity
L = length of pipe
g = acceleration due to gravity
D = pipe internal diameter

EOT

End of tubing.

MPP

Mid point of perforations.

Liquid to Gas Ratio

Piper assumes that liquid production will follow in a constant ratio to gas production, known as the liquid to gas ratio. Multiplying the gas rate by the liquid to gas ratio will calculate the liquid production for the well.

Liquid Loading

As natural gas is produced, the energy available to transport the produced fluids to surface declines. This transport energy eventually becomes low enough that flow rates are reduced and fluids produced with the gas are no longer carried to surface but are held up in the wellbore. These liquids accumulate in the wellbore over time, and cause additional hydrostatic back pressure. This phenomena is known as liquid loading.

Alias Name

The intent of the alias name is to provide another name for the well.

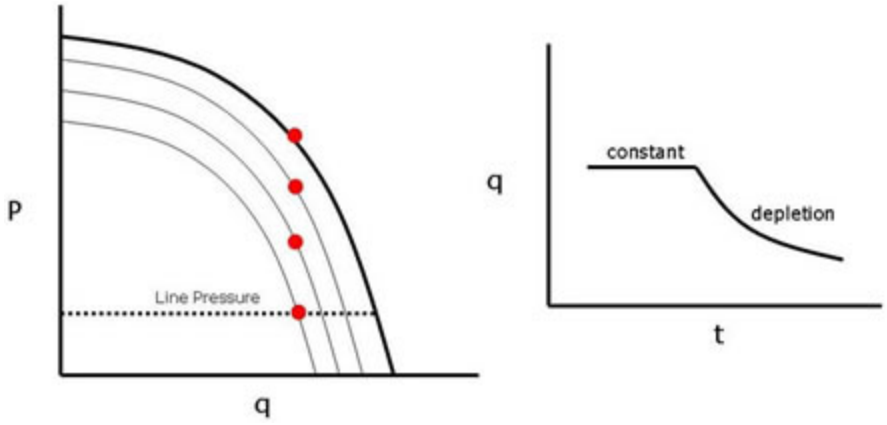
Minimum Gas Rate

Often the operating conditions of a well are such that below a certain rate, it is uneconomical or impractical to keep producing the well. This can be due to such factors as wellbore liquid load-up, or excessive operating costs like hydrate prevention, water disposal, etc. The minimum gas rate allows the user to set the rate at which a well will be shut-in. Once a well's flow rate falls below the Minimum Gas Rate, it is turned off and remains off.

Note: A well may prematurely fall below the Minimum Gas Rate if low contract rates cause the flow of all wells to be choked back. The user may choose to produce one well preferentially and delay the start of other wells until they are needed or set a minimum gas rate limit equal to 0 such that the well will come on-stream when the backpressure is low enough to commence production. Any well (regardless if a Minimum Gas Rate is specified or not) will be turned off if the rate drops below .005 MMscfd (0.14 $10^3 m^3/d$).

Maximum Gas Rate

The Maximum Allowable Gas Rate is a restriction that is applied to a well's production rate such that the well is not allowed to produce above that rate. This limitation may be caused by government regulations (allowables, off-target penalties, etc.) or good production practice. As the well deliverability decreases, the drawdown on the well will increase until it is equal to the line pressure. At this point the well will follow normal depletion.

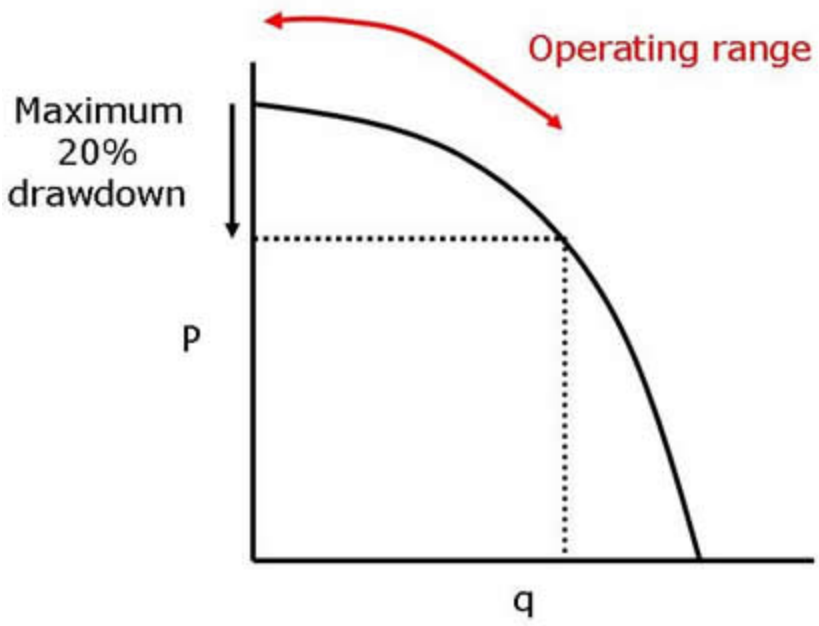


NOTE: The Maximum Allowable Gas Rate essentially acts in the same way as a contract restriction on an individual well. The difference is that Piper tracks the maximum deliverability potential which is calculated without contract restrictions but after the Maximum Allowable Gas Rate and Maximum Drawdown Limit restrictions are applied (any or all of the Maximum Allowable Gas Rate, Maximum Drawdown Limit and Minimum Rate can be applied to a well).

Maximum Drawdown Limit

For some wells, for example those wells that are experiencing water coning, it is desirable to impose a Maximum Drawdown Limit rather than a Maximum Rate. A commonly used value is 15 to 25%. Drawdown is defined as:

Drawdown = 100 x (shut-in pressure - flowing pressure)/shut-in pressure (%)



When a maximum drawdown is specified, the well will be choked back to a rate consistent with the pressure drawdown.

Note: The Maximum Drawdown Limit is expressed as a percentage but will result in a maximum rate limitation that decreases as the reservoir pressure decreases. This differs from the Maximum Rate option which remains fixed irrespective of reservoir pressure. The Maximum Drawdown Limit addresses reservoir management whereas the Maximum Rate handles surface or regulatory restrictions (any of all of the Maximum Rate, Maximum Drawdown Limit or Minimum Rate can be applied to a well).

Drawdown is calculated at the sandface if the Wellbore option is used. Otherwise, drawdown is calculated at the wellhead (the difference is significant only if you have high wellbore friction pressure losses i.e. a really good well).

UNITS : Percent (%)

DEFAULT : 100%

Surface Equipment Pressure Loss

For some wells, there is a restriction (for example a dehydrator, line heater, or riser) between the wellhead and the pipeline of the gathering system. The pressure drop across these vessels is handled as a fixed pressure drop (independent of rate).

UNITS: psia (kPaa)

DEFAULT: None

Measured Gas Line Pressure

The Measured Gas Line Pressure can be input and compared to the gas line pressure calculated by Piper. The difference between the measured gas line pressure and the calculated gas line pressure will be displayed in the bubble map menu when the Pipeline Pressure Calibration map type is selected.

Measured Water Line Pressure

The Measured Water Line Pressure can be input and compared to the gas line pressure calculated by Piper. The difference between the measured water line pressure and the calculated gas line pressure will be displayed in the bubble map menu when the Gas and Water Line Difference map type is selected.

PVT & viscosity correlations for black oil & no phase volumes

Pressure, volume, temperature (PVT) and viscosity correlations for the black oil method and no phase volumes are as follows:

Gas 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 50substances, 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.

Piper Detail: Gas properties can be determined directly from the known composition (mole fractions of each component). A pseudo-component is used with the sum of all components heavier than hexane. The molecular weight and gravity of the pseudo-component must be specified.

Gas Viscosity

Carr *et al:* Developed to predict the viscosity of gas hydrocarbon mixtures for temperatures between 32ºF and 400ºF and pressures up to 12,000 psi. Applies to both sweet and sour gas and is designed to handle non-hydrocarbon components (CO_2, H_2S, N_2) 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 100ºF - 340ºF. 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.

Oil PVT

	Range of values used in developing correlation							
Author(s)	Applicability	Oil Gravity	p_b	Pressure	Temperature	Gas Gravity	B_o	R_s
		(°API)	(psi)	(psi)	(°F)	(air rel.)	(bbl/STB)	(scf/STB)
De Ghetto et al.	heavy and extra-heavy crudes	6.0 - 22.3	209 - 4022	1038.5 - 7411.5	131.4 - 250.7	0.623 - 1.517	1.057 - 1.362	17 - 640
Glaso	North Sea oils	22.3 - 48.1	150 - 7000	400 - 4000	80 - 280	0.650 - 1.276	1.087 - 2.588	90 - 2637
Hanafy et al.	Egyptian (lighter) oils	17.8 - 47.7	36 - 5003		107 - 327	0.633 - 1.627	1.032 - 4.35	7 - 4272
Petrosky & Farshad	Gulf of Mexico (TX, LA) oils	16.3 - 45.0	1574 - 6523	1700 - 10692	114 - 288	0.578 - 0.852	1.118 - 1.623	217 - 1406
Standing	California oils	16.5 - 63.8	200 - 6000		100 - 260	0.500 - 1.500	1.024 - 2.15	20 - 1425
Vasquez & Beggs	general (world-wide) light & heavier crudes	15.3 - 59.5		140.7 - 9514.7		0.511 - 1.351		
Velarde et al.	general (world-wide) light & heavier crudes	12.0 - 53.4	106 - 5312		74 - 307	0.561 - 1.101	1.040 - 2.082	102 - 1808

Oil Viscosity

	Range of values used in developing correlation							
Author(s)	Applicability	Oil Gravity	p_b	Pressure	Temperature	Gas Gravity	R_s	Viscosity
		(°API)	(psi)	(psi)	(°F)	(air rel.)	(scf/STB)	(cP)
Beggs & Robinson	general dead and live oils	16.0 - 58.0		0 - 5250	70 - 295		20 - 2070	
Hanafy et al.	Egyptian (lighter) oils	17.8 - 47.7	36 - 5003		107 - 327	0.633 - 1.627	7 - 4272	0.119 - 106.6
Khan et al.	Saudi Arabian oils	14.3 - 44.6	107 - 4315	14.7 - 5015	75 - 240	0.752 - 1.367	24 - 1901	0.13 - 77.4

Water

Meehan: Generally applicable to calculate water properties while accounting for salt concentration.

Surface Facilities

Facilities include any of the elements (e.g., delivery points, compressors, wells, etc.) that you can add to the GIS map.

Delivery Points

A Delivery Point in Piper is considered to be a gas destination of sufficiently constant pressure that it can be considered to not vary as a function of gas rate. A Delivery Point is configurable on date basis, so it can vary from one date to the next. The only attribute of a Delivery Point is its Delivery Pressure.

There must be at least one delivery point in a model for the model to converge. More than one delivery point is allowed.

Multiple Delivery Points and Loop Links

There are many instances or reasons why the user may choose to incorporate multiple delivery points into a single Piper model.

In one case, the user has two separate systems and each system is delivering to separate locations. They may want to build the two systems in a single Piper file because at some point in the future a linkage between the systems may be built. Here, the two separate gathering systems can be constructed in a single file and no loop link needs to be defined. Once connectivity between the multiple systems within a single Piper file is made, a loop link needs to be defined. Loop links can be selected within the software in one of two ways.

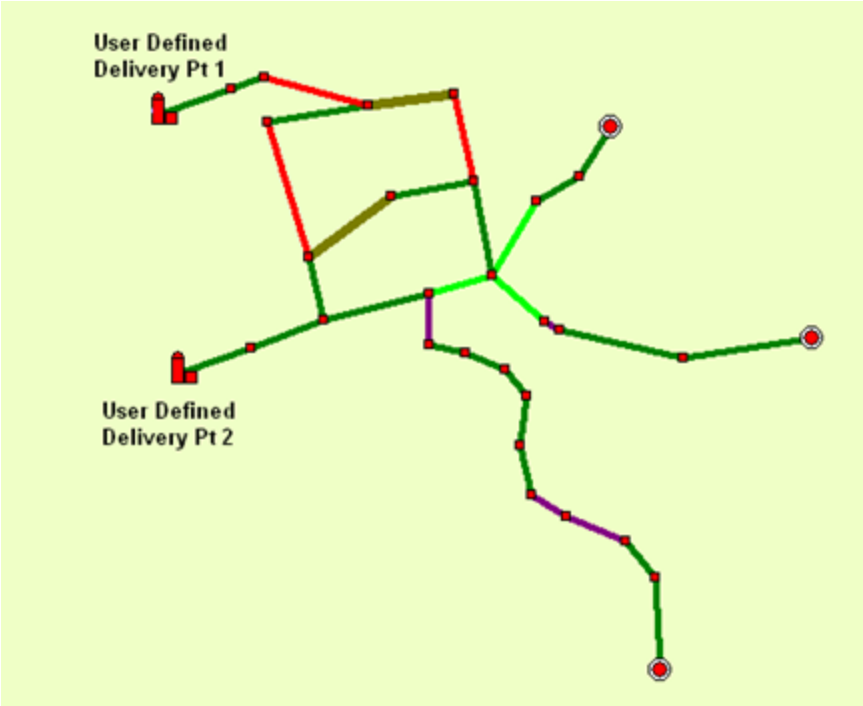
In a second case, the user may have a single gathering system that can deliver to two separate plants. They would like to model both plants and see how the gas is distributed between delivery points. Depending on the default settings (e.g., the default loop link selection method, which can be accessed from the default dialog box), you must select a loop link, or choose to have the software select a loop link based on an internal set of looping rules.

The forecast routine that Piper uses to solve files that contain multiple delivery points creates a pseudo flow loop within the system. When a flow loop is created in a Piper file, a loop link must be defined. Defining a line in a flow loop as a loop link is used within the software's forecast routine and allows for the desired system flows and pressures to be calculated.

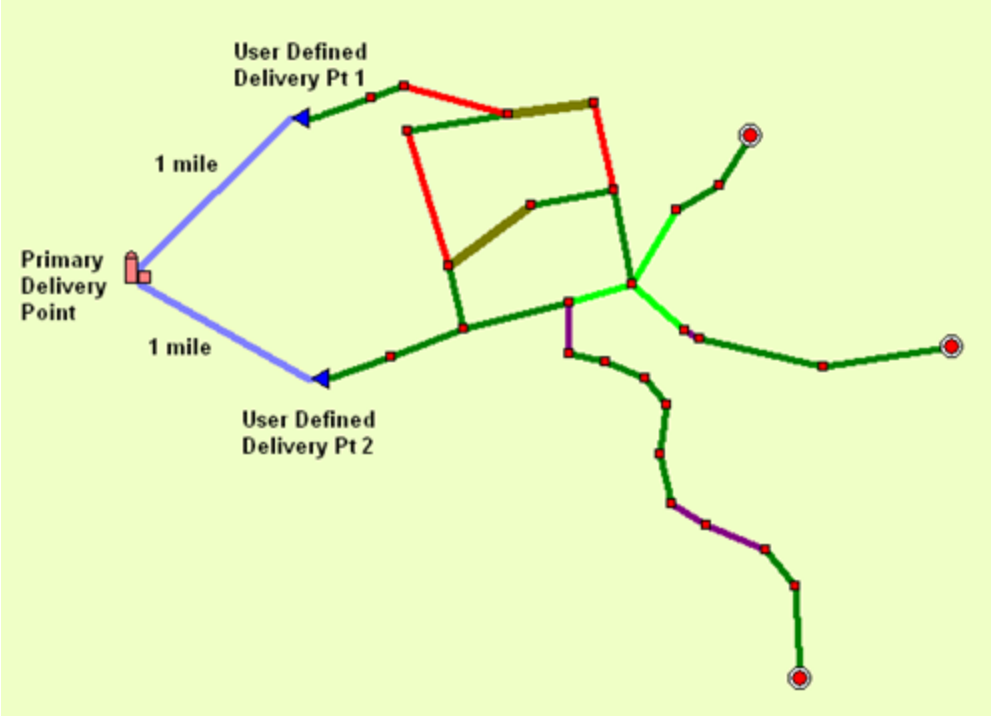
In systems where the user has defined more than one delivery, Piper defines a "primary" or "hidden" delivery point. This Primary Delivery Point is an internal point, visible to the software only. All user

defined delivery points are linked to this internal point. The following images illustrate the difference between what Piper displays on-screen (to the user) and what the software “sees” internally.

When the defining two delivery points within a single Piper file, the user sees the two delivery points that have been added either by on-screen techniques or through the delivery point editor. The loop links within the system can be distinguished by the yellow/green line color ( ).



The following image shows what is used internally within the software; it represents what is used in the software forecasting routine. Piper sees a Primary Delivery point through which all system gas must flow, and two single suction compressors that are attached to the Primary Delivery with null diameter lines of 1 mile length. Each additional delivery point defined in a multiple delivery point model will be represented internally in the same manner and connected to the Primary Delivery as stated above.



Note: When multiple delivery points are defined in Piper a flow loop has been created and a loop link needs to be defined.

Two methods exist for defining loop links within the software:

1. User Defined Loop Links (user selects the location of loop links and designates the chosen link as a loop link)
2. Piper automatic loop link selection (software selects the loop link based on a set of pre-defined looping rules contained within the software)

For additional information on loop links, see adding loop links.

Expected behavior when multiple delivery points are added

Multiple Delivery Points in a Single Connected Gathering System

When multiple delivery points are connected to a single gathering system, and the auto-loop link routine is enabled (the default for new models), the user should expect that the Piper will define an additional loop link in the system that represents the connection through the two delivery points. For each additional delivery point, users should expect an additional loop link.

When multiple delivery points are connected to a single gathering system and if the auto-loop link routine is not enabled (the default for an existing model built in a previous version), the user will have

to define a loop link that will represent the connection through the two delivery points. The steps for doing so are provided below, but for beginning users not familiar with loop links it is advised that you contact IHSsupport for help.

1. When the second (third, fourth, etc) delivery point is added and connected to the, a notification will be provided in the status windowthat a loop has been added and a link disabled.
2. Make note of the link that has been disabled.
3. Go into the Gathering System editor and find the link that has been disabled.
4. Re-enable the link and define it as a loop link by toggling on the “Looped” toggle and giving the link a UID
5. Exit the Gathering System editor
6. Press Ctrl-L and hover over the loop link that was just added to view the loop – note the loop that should go through the two delivery points
7. If the loop link is not in an ideal location (as per the rules of looping), modify the loop link as needed

Multiple Delivery Points in Unconnected Gathering Systems

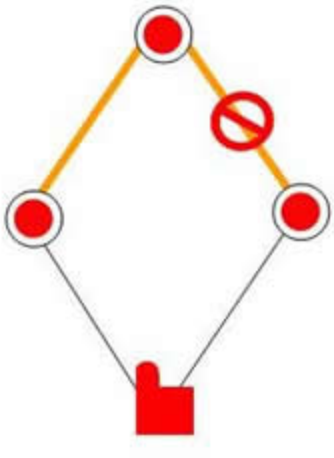
When multiple delivery points are added to unconnected gathering systems, the user should expect that no loop links will be added by Piper. The systems should behave independently. It is only internally during the solution process that Piper will treat the delivery points separately

Loops

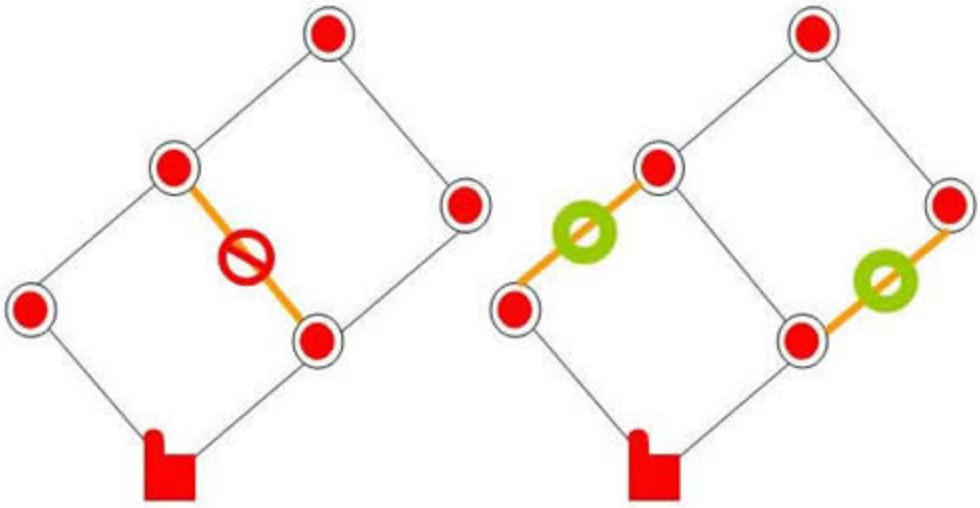
Rules for Line Looping

These are the current "rules" for using the line looping in Piper. Loop links are designated in the gathering system editor by mouse clicking the toggle in the "Looped" column for the appropriate link.

1. Only one loop link can be designated for each loop; otherwise, Piper will not be able to complete the connection and a "Link not used" error will occur. The second loop link is not valid.

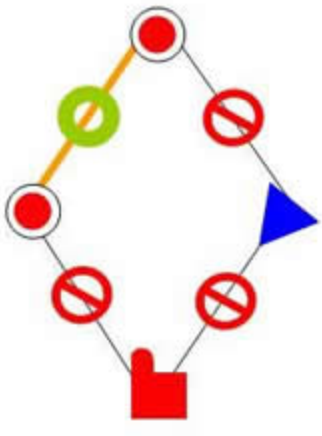


2. Two loops can not share the same loop link.



3. In flow loops, a loop link should be located near nodes where gas flow is expected to split. That is, where the flow direction "arrows" diverge as opposed to where "arrows" converge. A quick way to do this is to place the loop link in the loop as far away from the delivery point as possible. Another preliminary way to do this is to place the loop link at a point in the loop that is equidistant in each branch from the delivery point. Start by counting the number of links in each branch required to reach the proposed loop link.

4. Do not connect loop links to the delivery point, compressors, contracts, dehydrators or refrigeration facilities. The only valid nodes for connecting loop links are nodes with no attached facilities and nodes with wells. Do not designate links with any other node type as loop links. Piper may not always transfer gas and liquid volumes accurately in these situations.



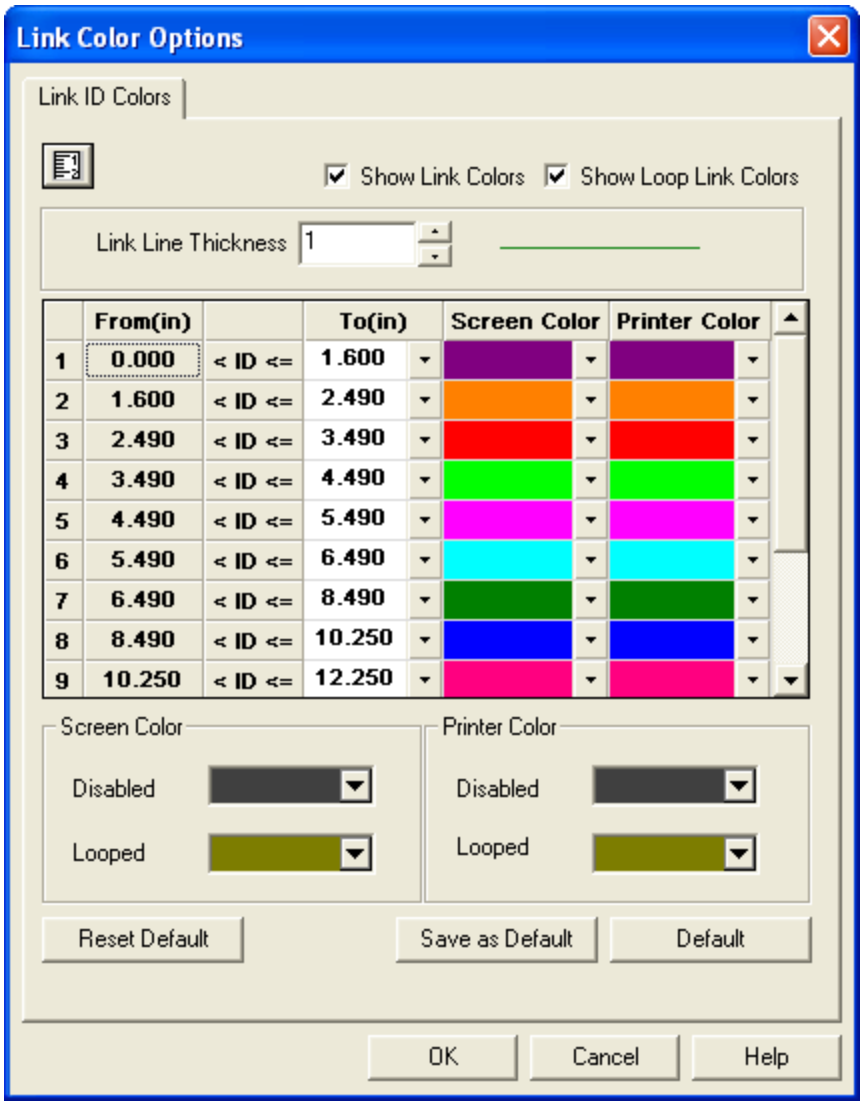
5. Compressors, contracts, dehydrators and refrigeration facilities should generally be located between the delivery point and loop links. This pre-supposes that the loop link has been placed at a point in compliance with point # 3. These facilities orient themselves such that their inlets face the loop link and their outlets face the delivery point. Note in the following schematics the loop link should not be connected to the delivery point, compressors, contracts, refrigeration facilities and dehydrators.

Unique ID

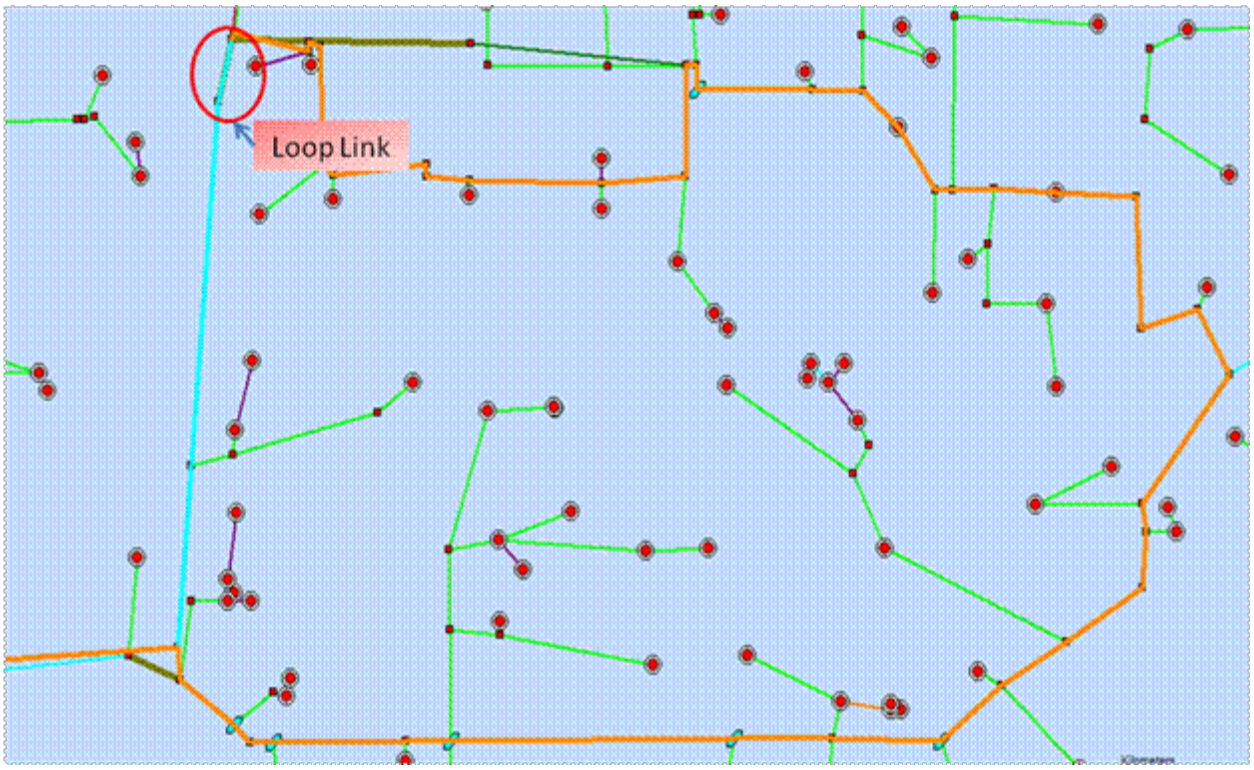
The unique ID is used as an internal identifier by Piper. The user must specify the unique ID for each loop that is specified. The unique ID can contain either a letter or number designation. It is only required that no two unique ID's use the same identifier.

Displaying or Hiding Loop Links and Loops

The loop links chosen either by the user or by Piper will, by default, be displayed on-screen with a thick, gold colored link. Loop links can be hidden from display through an option in the Link Colors Options to “Show Loop Link Colors”.



To display the loop that a loop link is associated with, the Ctrl-L command can be used. After pressing Ctrl-L, with the mouse cursor, hover over the loop link that is of interest. The loop that the loop link is associated with should become highlighted in two colors, orange and blue. The two colors represent the two potential directions of flow around the loop. Where the blue and orange line converge and form a single orange line, that is where the loop ties back into a single line. See the figure below for an illustration:



Tips

Before constructing a complicated gathering system that includes flow loops, create a simplified sketch of the system and identify ALL loops. Then, choose the line loop locations based on the above rules.
Since Loop Links are special links that are really termination points for connected branches, it is possible to specify loop links that isolate links from the delivery point. Piper will interpret isolated links as unused facilities and disable those links. Disabled links and facilities will not be displayed on-screen.

If a portion of a gathering system is not shown on-screen and a list of "Link not used" errors is displayed in the status window, DO NOT PANIC. This message indicates a link node name may have been improperly entered or the designated loop link violates one or more of the above rules. Review the above rules and designate a different link as the loop link to solve the problem.

Nodes

Nodes are connection points. Each Link in a gathering system requires a Source Node name and a Destination Node name. Separate links each having the same node names will be connected together. Successive links, joined by the ends having identical node names, form the gathering sys-

tem model we see on-screen. The Source node name and Destination node name cannot be identical for a single link.

Nodes are displayed on-screen as squares to make it easier to see and work with them.

Nodes allow the attachment of various facilities such as wells, compressors, contracts, dehydrators, NGL recovery units (Refrigeration) or amine plants. Only one facility can be attached to a node at one time. This was done to simplify display options as it eliminates the need for combination symbols or setting up a hierarchy of symbols used to represent each of these facilities.

Source Node

The Source Node Name is the name given to the source node for each Link in a gathering system model. This can be any alphanumeric combination; for example Junction 23-4, or well 3-16-24-32 W4M, or Watering Hole. For your convenience, the program does not differentiate between upper-case and lowercase letters. For example, B-34 is equivalent to b-34. Use of spaces, alphanumeric and numeric characters as well as other symbols such as dashes (-), underscores (_), plus signs (+), number signs (#), slashes (/), etc. are allowed.

UNITS: None

DEFAULT: None

Destination Node

The Destination Node is the name given to the Destination for each Link in a gathering system model. This can be any alphanumeric combination: for example Junction 23-4, or well 3-16-24-32 W4M, or Watering Hole. For your convenience, the program does not differentiate between upper-case and lowercase letters. For example, B-34 is equivalent to b-34. Use of spaces, alphanumeric and numeric characters as well as other symbols such as dashes (-), underscores (_), plus signs (+), number signs (#), slashes (/), etc. are allowed.

UNITS: None

DEFAULT: None

Node Gas Rate

This is the measured gas rate through a particular node in the gathering system. This information along with the Measured Pressure can be displayed on screen and used to tune the model.

UNITS: MMscfd ($10^3 m^3/d$)

DEFAULT: None

Node Liquid Rate

This is the measured liquid rate at a node in the gathering system.

UNITS: bbl/d (m^3/d)

DEFAULT: 0

Node Measured Pressure

This is the measured pressure at a particular node in the gathering system. You can access the Measured Pressure from the Node editor. This information can be displayed on screen and used to tune the model.

UNITS: psia (kPaa)

DEFAULT: 0

Node Remarks

This field allows for the entry of Node specific remarks. The user can display these on the gathering system map.

UNITS: None

DEFAULT: None

Compressors

There are primarily two types of compressors used by the petroleum industry. These are reciprocating compressors and rotary screw compressors. The Piper approach to modeling compressors is independent of the compressor being modeled, so the user should be able to model both compressor types. The user is expected to supply information that should be readily available from the manufacturer. The user is encouraged to always plot current conditions of suction pressure and throughput to ensure that the compressor is being utilized at or near to design specifications.

It has been our experience that operators rarely utilize compressors at design specifications. Some common reasons that the actual utilization differs when compared to design are as follows:

- reduced RPM's
- unloaded head-end in double acting compressors

- utilization of valve pockets to reduce capacity
- multiple units
- modification to basic clearance volumes

Physical Description

The unit we commonly call a compressor is really two separate machines that have been joined together. The driver is an engine that supplies the energy or horsepower to compress the gas.

The design of a compressor is a complex task as it must account for the compression of a non-ideal gas with its associated thermodynamic properties and the mechanical requirements of the machinery which has limits for volumetric efficiency, mechanical loads, temperature restriction and operating pressure restrictions.

Modeling Compression

In general, there are three ways of handling Compressors in Piper:

1. **No Compressor Curves or Horsepower Limitations specified:** this option is generally used when attempting to get a preliminary idea of deliverability and horsepower requirements. This method estimates the horsepower required to maintain the specified Minimum Inlet Pressure. Since this method will maximize deliverability without regard for the realities of compressor sizing, it should only be used to determine peak horsepower requirements. This approach to compression is generally used in model calibration, where only the current condition of operation of the compressor is desired. This approach can also be used to model secondary compression, as the primary compression will dictate the secondary compressors performance.
2. **No Compressor Curves but Horsepower Limitations apply:** we call this the infinitely flexible Compressor as it assumes the compressor will be physically configured, as required, to handle whatever gas rate the field can supply at a given Inlet Pressure and maximum available horsepower. This method is used mainly to generate deliverability forecasts for a range of horsepower limitations to provide an accurate estimate of long-term deliverability versus installed horsepower. This method assumes the operator will reconfigure the Compressor as required to maintain optimum deliverability within the bounds of the specified Minimum Inlet Pressure and maximum Horsepower Available.
3. **Specify Compressor Curves:** this option accurately calculates the relationship between Compressor Capacity and field deliverability. Compressor Curves are generally available from the manufacturer. However, if they are not available and the Compressor is currently working at its capacity, input the current measured suction pressure and gas throughput in

the Maximum Inlet Pressure and Maximum Inlet Rate columns, respectively. Ensure the measured discharge pressure for the compressor is reflected in the model match. This methodology will provide an accurate compressor curve for the current compressor configuration. This method can be very pessimistic when used for long term deliverability forecasting as the compressor may have other configurations that have not been used yet.

To turn the capacity curves function on, click the "Curves On/Off" toggle situated under the Compressor type column, in the Compressor Editor. Piper will open the cells corresponding to the Maximum Inlet Pressure, Minimum Inlet Rate, Maximum Inlet Rate, Minimum Inlet Pressure, Mid Inlet Pressure and Mid Inlet Rate for data input.

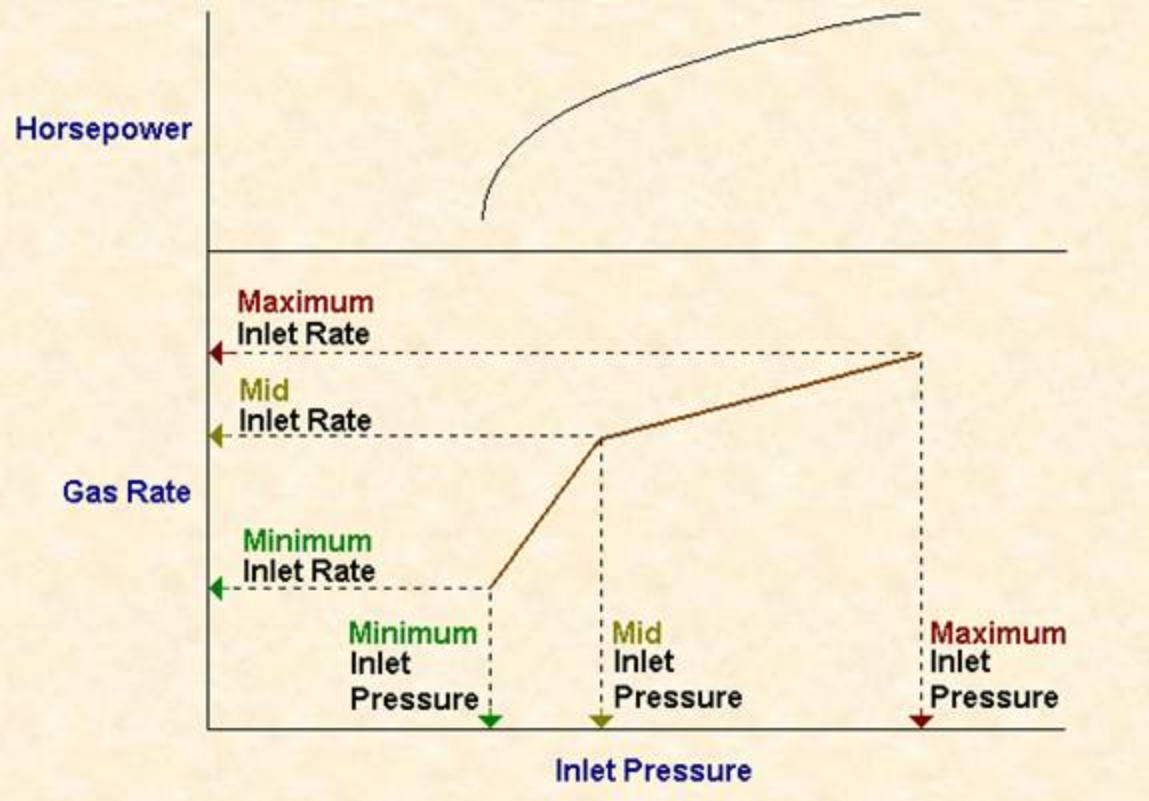


Compressors using Capacity Curves

This option uses compressor capacity curves to simulate the compressor performance. Compressor capacity curves define a specific compressor configuration. In Piper, a specific compressor configuration means the current valve pocket settings, number of stages, etc.

The program uses this information to internally construct a straight line Suction Pressure versus Inlet Gas Capacity correlation for the compressor. These variables can be scheduled through time making modeling of various compressor configurations relatively easy.

Compressor curves are generally presented by the manufacturer as follows:

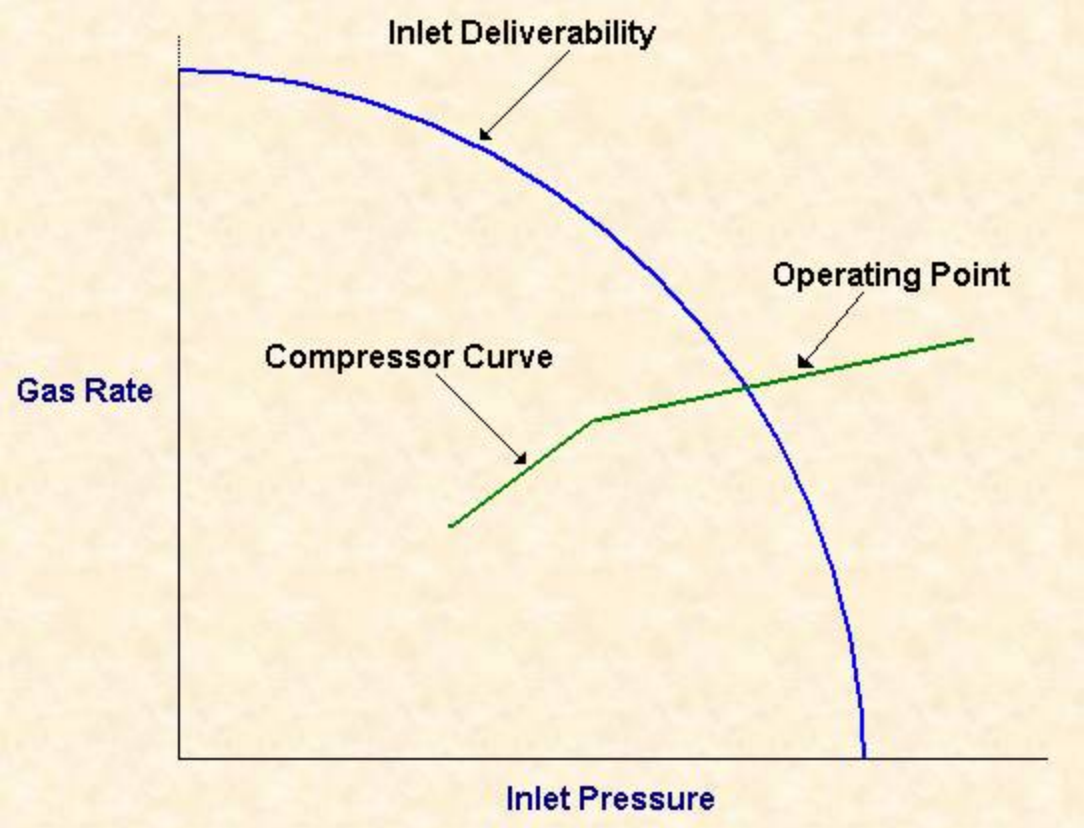


The lower curve represents the relationship between suction pressure and gas rate. The simplest version of this relationship is a straight line passing through the origin.

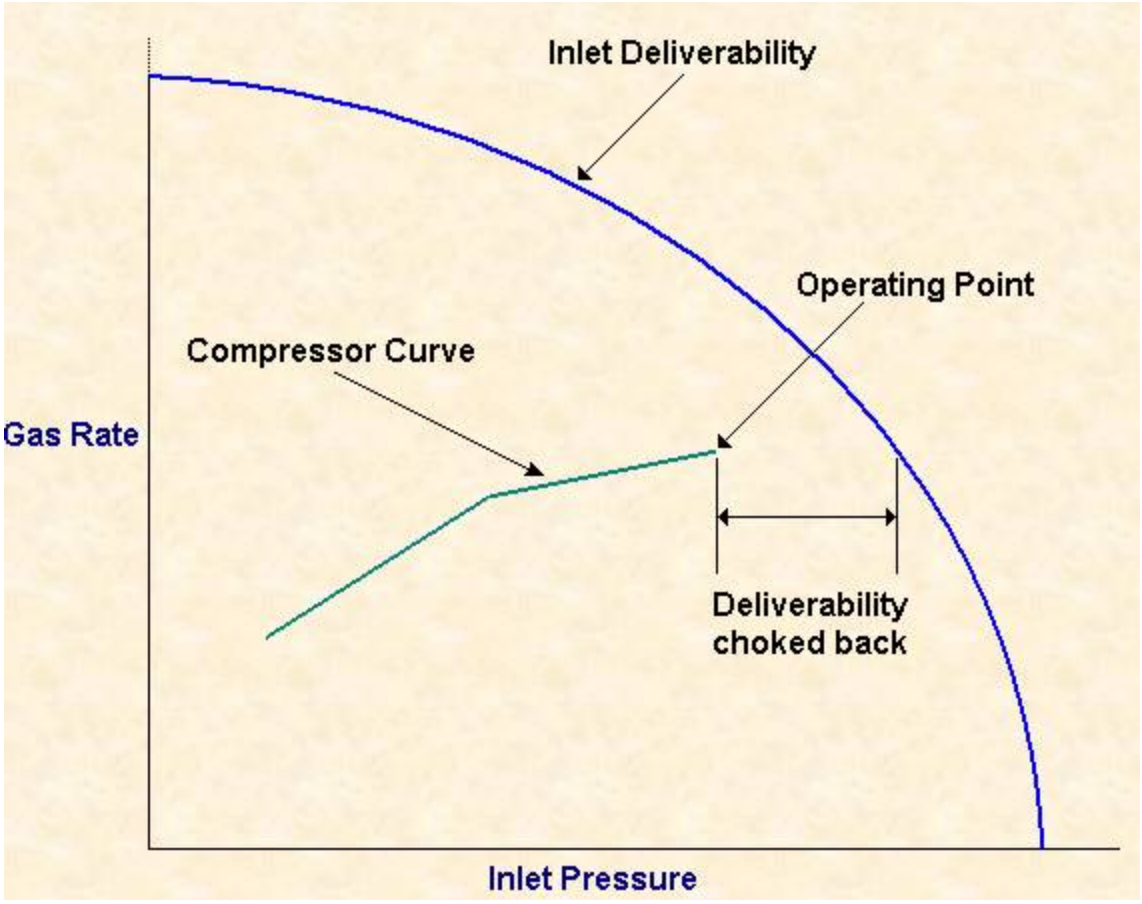
Gas Rate = Slope x Suction Pressure

which is defined in the program by input of the Maximum Inlet Pressure and Maximum Inlet Rate. By using this methodology the program can completely define the compressor curve with three (3) input variables. These parameters define the upper limit of a compressor's range. The lower limit of the range is defined by the Minimum Inlet Pressure .

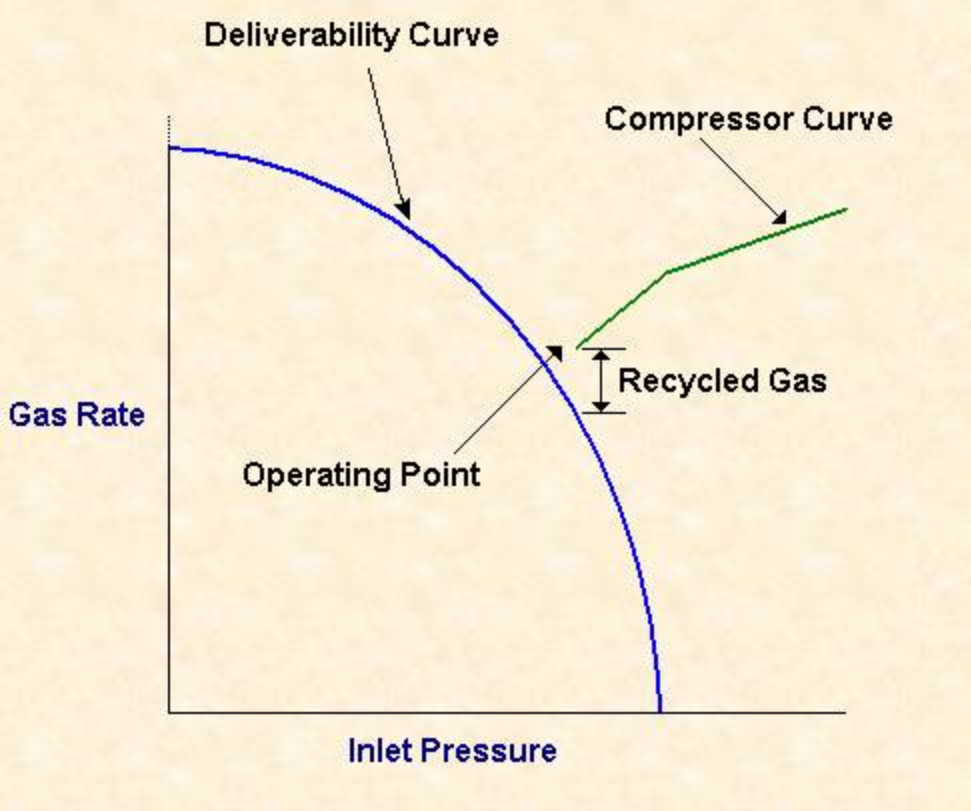
The Figure shown below demonstrates how the program calculates the compressor inlet pressure and gas throughput called the operating point. The deliverability available from the field is shown as a downward sloped curve, whereas the compressor curve is an upward sloped straight line. The intersection of these curves is the operating point.



In the situation where the field has more deliverability than the compressor can handle, as shown in the Figure below, the program invokes a choke between the Inlet and the suction of the compressor. This drops the pressure the compressor sees to its Maximum Inlet Pressure.



In the situation where the field does not have sufficient deliverability at the Minimum Inlet Pressure for the compressor to properly fill the cylinders, the compressor will invoke a recycle stream to maintain the required volume of gas as dictated by the compressor curve. The compressor will consequently continue to produce at its Minimum Inlet Pressure and corresponding minimum gas rate while the net gas rate discharged by the compressor will be equal to field production. The lowest limit for this scenario occurs when the field can no longer supply gas at the Minimum Inlet Pressure of the compressor. At this point the compressor will be on 100% recycle.



Compressor Curves are generally available from the manufacturer. However, if they are not available and the Compressor is currently working at its capacity, input the current measured suction pressure and gas throughput in the Maximum Inlet Pressure and Maximum Inlet Rate, respectively. Ensure the measured discharge pressure for the compressor is reflected in the model match. This methodology will provide an accurate compressor curve for the current compressor configuration. This method can be very pessimistic when used for long term deliverability forecasting as the compressor may have other configurations that have not been used yet.

On-Stream Date

The date in which a compressor is to become active in the forecast interval set in the Forecast View tab. A compressor becomes active on the later of the on-stream date or the first date of the forecast interval. If the on-stream date is blank, a compressor is active the first forecast date.

UNITS: MM/DD/YYYY

DEFAULT: None

Minimum Inlet Rate

The Minimum Inlet Rate, Maximum Inlet Pressure and the Maximum Inlet Rate input cells become active in the compressor editor when the Compressor Curves function is turned on. The Minimum Inlet Rate defines the lower gas rate capacity for a specific compressor. The Minimum Inlet Rate should be obtained from compressor manufacturer performance curves. If not specified, the minimum inlet rate will be calculated based on the assumption that the capacity curve will be a straight line going from "0" capacity and "0" pressure to the input data for maximum inlet pressure and maximum inlet rate.

UNITS: MMscfd (103m3/d)

DEFAULT: 0

Mid Inlet Rate

The Mid Inlet Rate input cell becomes active in the compressor editor when the Compressor Curves function is turned on. The Maximum Inlet Rate defines the upper gas rate capacity for a specific compressor. The Maximum Inlet Rate should be obtained from the compressor manufacturer performance curves.

UNITS: MMscfd (103m3/d)

DEFAULT: None

Maximum Inlet Rate

The Minimum Inlet Rate, Mid Inlet Rate, Mid Suction Pressure, Maximum Inlet Pressure and the Maximum Inlet Rate input cells become active in the compressor editor when the Compressor Curves function is turned on. The Maximum Inlet Rate defines the upper gas rate capacity for a specific compressor. The Maximum Inlet Rate should be obtained from the compressor manufacturer performance curves.

UNITS: MMscfd (103m3/d)

DEFAULT: None

Minimum Suction Pressure

Minimum Suction Pressure is the lowest achievable suction pressure for a compressor. This value is a function of the compressor design and is determined using the compressor capacity curves.

UNITS: kPaa

DEFAULT: None

Mid Suction Pressure

Mid Suction Pressure is the mid-point achievable suction pressure for a compressor. This value is a function of the compressor design and is determined using the compressor capacity curves.

UNITS: psia (kPaa)

DEFAULT: None

Maximum Suction Pressure

Maximum Suction Pressure is the maximum achievable suction pressure for a compressor. This value is a function of the compressor design and is determined using the compressor capacity curves.

UNITS: psia (kPaa)

DEFAULT: None

Other Compressor Terminology

Horsepower Utilized and Available

The **horsepower utilized**is the amount of energy that is required to maintain the specified state of operation of a compressor. Piper calculates horsepower used based on the assumption that the compression process is an isothermal process. Piper then corrects the result by a 10% safety factor. The resultant equation that Piper uses to calculate horsepower is:

$$HP = 65\,q \ln\left(\frac{P_d}{P_s}\right)$$

q = MMcfd
P = psia

This equation builds the effect of gas gravity, compressibility, inlet temperature as well as the 10% safety factor into the constant of 65. There is no consideration in the calculation for any losses. Only the energy required to compress the gas is considered

This horsepower utilized is always equal to or less than the horsepower available.

The **horsepower available** in Piper is the maximum horsepower available to compress the gas. The compressor drive motor is generally sized to match the compressor capacity requirements. However, if the Horsepower Available is undersized relative to the compressor capacity and field deliverability, Piper will progressively choke the inlet pressure at the compressor until the utilized horsepower is equal to the horsepower available. This will reduce the gas rate flowing from the field and will create a pressure differential between the inlet and suction of the compressor. Piper differentiates pressure information at the entry to the compressor as the INLET (the backpressure the wells produce against) and SUCTION (the pressure of the gas entering the compressor). If compressor curves are not specified, then Piper will increase the pressure differential until the horsepower limitation is honored. If compressor curves are specified, Piper will again increase the pressure differential until the horsepower limitation is honored but then will also search for a solution that honors the rate capacity - suction pressure relationship defined by the compressor curve. It is extremely important that the horsepower available and the rate capacity - suction pressure relationship be matched sets of data.

Schedule changes in Horsepower Available can be inserted on a monthly basis. The user only has to fill in the months in which a change is made. By clicking the button situated on the right side of each cell, the change will be copied down. Proceed in a similar manner for every change that you want to insert.

UNITS: HP (kW)

DEFAULT: Unlimited

Flow Limit

The Flow Limit option allows you to specify the maximum flow that can go through the compressor. The Flow LImit option allows you to model a valve compressor.

Compressor Fuel Gas

Natural gas compressors consume natural gas as fuel. This gas can be taken from an alternate source or from the gas stream entering the facility. Fuel is taken from the gathering system to run the compressor is called Fuel Gas. The Fuel Gas consumption is related to the horsepower used, which in turn, is related to the volume of gas being compressed. When no horsepower is being used, the Fuel Gas is zero. Fuel usage in Piper is expressed as a percentage of the throughput. A reasonable usage number is 3%. Fuel usage should be entered when tuning a gathering system.

UNITS: Percent (%)

DEFAULT: 0

Pumps

There are two types of pumps modeled in Piper:

- Pump Curve – a curve is required.
- Constant Head – only one operating point needs to be entered.

When entering a curve in the pump curve editor, as the pressure increases, the rate must decrease. Otherwise, an error message will appear.

If the operating conditions fall between or outside of the pump curve, Piper will interpolate along the pump curve points on an iterative basis to determine the pressure change across the pump for a given liquid rate being pumped.

When a constant head is entered, Piper applies the specified head across the pump regardless of the rate being pumped.

If the rate across the pump is zero, the head applied across the pump is set to zero, as the pump is considered to be off-line.

If the pump converges to an operating point outside of the specified pump curve, Piper will accept the converged solution, but will provide a warning in the status window that the pump may be operating outside of its allowable limits, and in practice, behavior may be unstable.

Efficiency and Horsepower

Piper calculates the pump efficiency and required horsepower using the following equations:

$$Eff = 80 - 0.2855 \cdot H + 0.000378 \cdot H \cdot Q - 0.000000238 \cdot H \cdot Q^2 + 0.000539 \cdot H^2 - 0.0000000639 \cdot Q \cdot H^2$$

$$HP = \frac{Q \cdot H \cdot SG}{3960 \cdot Eff}$$

For the range of values:

100-1000 USGPM=4500-45000 bbl/d

Pressure in Head 50-300 ft or 20-250 psi

If the operating conditions fall outside of this range,Piper will calculate the pump efficiency and horsepower, but these values will not be displayed.

Viscosity

For the pump calculations, Piper uses the combined viscosity. The combined viscosity can be displayed at each node and facility and is calculated using the viscosity correlation that has been defined in the Correlations editor. By default this correlation is Vasquez and Beggs for black oil models, and Lorenz, Bray and Clark for equation of state models.

The viscosity entered in the pump curve dialog box is the viscosity at which the pump curve was created. This means that the associated pressure drop may be different, based on the viscosity difference.

Intakes and Offtakes

Offtakes are used to remove gas from a system at a fixed rate. Offtakes are useful where gas must be delivered at a specific rate and a minimum pressure. Examples would be power plants, fertilizer plants and other industrial or domestic sales points. A typical use of an intake would be cases where gas will be supplied from some third party.

Intakes are used to inject gas into a system at a fixed rate. This means that the model would have to include a source of gas that would not affect the deliverability of the reservoir.

One common use of intakes and offtakes is for the simplification of large gathering systems. A large gathering system may be excessively cumbersome to deal with, and the use of intakes and offtakes to approximate the gas flows in areas of lessor importance can reduce model size and solution time. Another use may be to simulate the existence of multiple gas delivery points.

Stage

This option is only valid for offtakes. By selecting this option, Piper will adjust the rate into the offtake after the minimum pressure of the offtake has been reached. This will continue until the rate reaches zero.

When staging is turned off, gas cannot be delivered below the specified minimum pressure for the offtake.

Minimum Pressure

This option is only valid for offtakes. This is the lowest back pressure against which an offtake is still able to operate. A non-zero entry must be supplied for minimum pressure.

UNITS: psia (kPaA)

DEFAULT: None

Gas Rate

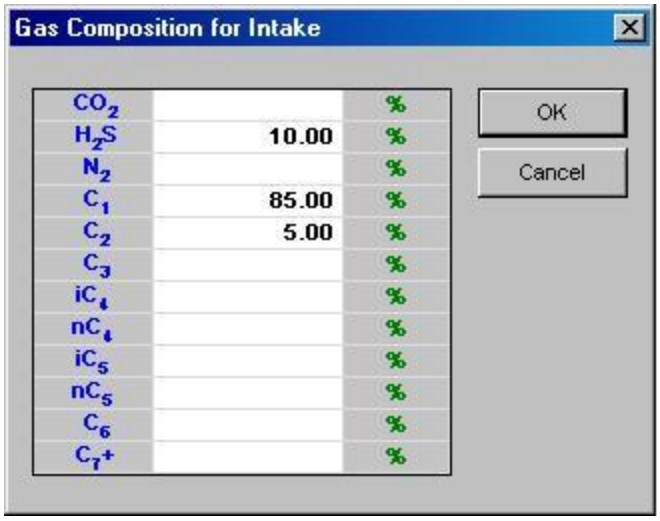
This is the rate of gas that is injected or removed from a system through the offtake or intake. For an offtake with staging active, once the minimum pressure has been reached, this rate will decrease in order to maintain that pressure.

Gas Props

This option is only valid for intakes. This is used to specify the composition of the gas injected that is into the system. The default is use of simplified gas properties (G, CO2, H2S, and N2 only).



If composition tracking is turned on, then the required input switches to a C7+ analysis.



Contracts

Contracts are used to restrict flow through a node to a set value. This value is referred to as the Daily Contract Volume. Contract restrictions are currently calculated based on raw gas throughput at the contract node. Contracts can be located at any available node in the system.

A contract will automatically restrict wells upstream of it to flow at a reduced rate so that the rate through the contract point is not greater then the contracted daily volume. To achieve the desired flow rate, the contract acts as a variable pressure loss, adjusting the pressure loss until it produces the desired contracted volume.

Contracts are represented in the gathering system map as a "Bow Tie".

Contract Status

To access the Contract Status, click on Contracts under the Facilities menu. The Contract Status is a toggle that allows the user the capability to turn a contract on or off regardless of the data entered into the contract editor. Changes to the contract status can be performed throughout the forecast.

UNITS: None

DEFAULT : Off

Daily Contract Volume

To access the daily contract rate, click on Contracts under the Facilities menu. The contract editor window will be open, allowing the daily contract rate input under the daily contract rate column.

The Daily Contract Rate specifies the average daily raw gas rate that can be produced through the contract node. The contract rate is achieved by choking the gas flowing into the contract point.

Changes to the Daily Contract Rate can be done throughout the forecast. For technical and practical reasons, a flow limit input is included with each compressor. This eliminates the problem of placing both, a contract and a compressor at one node.

If you need to give a name to the Compressor Contract (i.e. NVL, TCPL, etc.) this is best done via the Remarks cell. A contract specified at a compressor is assumed to occur at the outlet of the compressor. Compressor Fuel Gas is also removed at the outlet of the compressor but prior to the contract.

UNITS: MMscfd (103m3/d)

DEFAULT: None

Contract Name

Piper treats contracts like a facility that can be attached to a node. To attach a facility to a node, select the appropriate node name from the list of available node names in the contract editor.

UNITS: None

DEFAULT: None

Separators

Separators are used to remove free liquids from the gas stream. Separators can be located at any available node in the system. A fixed pressure loss across the facility and the amount of fuel gas that is to be extracted at this point can also be specified. In Piper a separator can be specified to remove either all or part of the liquids in the gas stream.

Separator Outlet Options

There are multiple options available for the outlet(s) of the separator. These are selected with the drop-down menu in the “Recombine" column. The table below details how outlets are set based on the different options.

Recombine Option	Description
None	Three outlets: gas, oil, and water. Gas is only sent to the gas outlet (there is no gas in the oil or water outlets). The volumes of oil and water removed are sent to their respective outlets with a portion being sent to the other liquid outlet depending on the efficiency of liquid removal from gas and water removal from oil.
All	One outlet with all gas (after fuel gas removed), oil, and water.
Gas Oil	Two outlets: gas + oil and water. The amount of removed water is sent to the water outlet with the remainder sent to the gas + oil outlet. The Oil-Water Efficiency determines the amount of oil sent to the water outlet.
Gas Water	Two outlets: gas + water and oil. The amount of removed oil is sent to the oil outlet with the remainder sent to the gas + water outlet. The Oil-Water Efficiency determines the amount of water sent to the oil outlet.
Liquid	Two outlets: gas and liquid. Only the Gas-Liquid Efficiency is used in separating the volumes of oil and water between the two outlets.

Separator Gas-Liquid Efficiency

Separators typically remove a percentage of the total liquids flowing through them. The amount of oil and water removed from the gas stream is specified as a percentage of throughput.

UNITS: Percent (%)

DEFAULT: 100.00%

Separator Oil-Water Efficiency

When oil and water are primarily sent to different outlets (recombine state set to “None?, “Gas Oil? or “Gas Water?), the amount of oil sent to the oil outlet is the specified percentage of the total removed oil volume from the gas outlet. The amount of water sent to the water outlet is the specified percentage of the total removed water volume from the gas outlet. The remainder of these is sent to the other liquid outlet.

UNITS: Percent (%)

DEFAULT: 100.00%

Separator Fuel Gas

Fuel gas is sometimes required to run a separator. If the facility requires natural gas as fuel and it is taken from the gas stream, this variable will let the facility remove a percentage of the unit's throughput. This variable should be specified when tuning a gathering system, as the gas removed will lower the throughput for the pipeline downstream of the separator.

UNITS: Percent (%)

DEFAULT: 0

Separator Pressure Loss

The separator facility may cause a pressure drop. This value represents the pressure loss (default = 0). If the facility causes no pressure drop, then the default value of zero is used, otherwise, the estimated pressure loss across this facility has to be specified.

UNITS: psia (kPaA)

DEFAULT: 0

Refrigeration Units

A refrigeration unit is used to condense the heavier hydrocarbons into liquid form. These 'condensates' can then be removed from the gas stream.

To use the refrigeration unit in Piper, the amount of condensate that is recovered has to be input. The condensate recovery in Piper is divided up into Propane, Butane and Pentane + recoveries.

Refrigeration plants can be located at any available node in the system. A fixed pressure loss across the facility and the amount of fuel gas that is to be extracted at this point can also be specified.

The input required for each of the recovered hydrocarbons depends upon whether a simple or detailed gas composition is being used. If a simple gas composition is specified, then the input requires the amount of each hydrocarbon stream to be specified on the basis of a Liquid to Gas ratio. If a detailed gas composition is specified, each hydrocarbon stream is specified on a volumetric percentage basis of the total volume of that hydrocarbon. This is referred to as the recovery efficiency.

Refrigeration Plant Fuel Gas

Fuel gas is sometimes required to run a refrigeration plant. If the facility requires natural gas as fuel and it is taken from the gas stream, this variable will let the facility remove a percentage of the unit's throughput. This variable should be specified when tuning a gathering system as the gas removed will lower the throughput for the pipeline downstream of the refrigeration plant.

UNITS: Percent (%)

DEFAULT: 0

Recovery Efficiency

The recovery efficiency for each hydrocarbon stream is specified when the detailed gas composition option has been activated and thus when the volumetric content of each hydrocarbon stream within the gas solution is known.

Propane (C3) Recovery Efficiency

Refrigeration Plants typically remove a percentage of the total Propane throughput. The amount of Propane removed is specified as a percentage in the Refrigeration Plant editor when gas composition is turned on. If gas composition is turned off, then propane to gas ratio (bbls/MMcf) has to be specified in the Refrigeration Plant editor.

UNITS: Percent (%)

DEFAULT: 90.00%

Butane (C4) Recovery Efficiency

Refrigeration Plants typically remove a percentage of the total Butanes throughput. The amount of Butane removed is specified as a percentage in the Refrigeration Plant editor when gas composition is turned on. If gas composition is turned off, then, butane to gas ratio (bbls/MMcf) has to be specified in the Refrigeration Plant editor.

UNITS: Percent (%)

DEFAULT: 95.00%

Pentanes+ (C5+) Recovery Efficiency

Refrigeration Plants typically remove most of the total Pentanes+ throughput. The amount of Pentanes+ removed is specified as a percentage in the Refrigeration Plant editor when gas composition is turned on. If gas composition is turned off, then, pentanes+ to gas ratio (bbls/MMcf) has to be specified in the Refrigeration Plant editor.

UNITS: Percent (%)

DEFAULT: 100.00%

NGL Rate

This rate refers to the total amount of hydrocarbons with equal or greater molecular mass than propane (C3) that have been removed by a refrigeration unit. This rate will show up in the display of refrigeration performance.

UNITS: Percent (%)

DEFAULT: 100.00%

Refrigeration Pressure Loss

The Refrigeration Plant facility may cause a pressure drop. This value represents the pressure loss (default = zero). If the facility causes no pressure drop, then the default value of zero is used, otherwise, the estimated pressure loss across the facility has to be specified in the Refrigeration Plant Editor.

UNITS: psia (kPaA)

DEFAULT: 0

Amine Plants

The presence of acid gases, H2S and/or CO2 in natural gas is undesirable. They enhance corrosion and must be removed prior to delivery to sales. There are a number of systems that can be used for removal of acid gases.

The purpose of an amine plant is to remove H2S and CO2 from a gas stream. This is accomplished by sweetening with a solution of water and an ethanolamine (15 to 60 wt%). Heating the solution and reducing the pressure can regenerate the sour amine.

Sweetening by ethanolamines is the most widely used type of acid-gas-removal system. The process is based on the principle that the acid gases, H2S and CO2, will react with ethanolamine at ordinary temperatures. The sour amine can be regenerated by heating the solution and reducing the pressure.

A number of different types of ethanolamine can be used in the process. Monoethanolamine (MEA), Diethanloamine (DEA), Diglycoamine (DGA) and Methyldiethanolamine (MDEA) are among those that are the most popular.

Amine Plants can be located at any available node in the system. The Amine Plant specifies the percentage of acid gases to be removed at a node. A fixed pressure loss across the facility and the amount of fuel gas that is to be extracted at this point can also be specified.

Amine CO2 Removal Efficiency

Amine Plants will remove a percentage of the total CO2from the inlet gas volume. The amount of CO2has to be specified as a percentage.

UNITS: Percent (%)

DEFAULT: None

H2S Removal Efficiency

Amine Plants will remove a percentage of the total H2S from the inlet gas volume. The amount of H2S has to be specified as a percentage.

UNITS: Percent (%)

DEFAULT: None

Amine Plant Fuel Gas

Fuel gas may be sometimes required to run an amine plant. If the facility requires natural gas as fuel and it is taken from the gas stream, this variable will let the facility remove a percentage of gas at the amine plant outlet. This variable should be specified when tuning a system as the gas removed will lower the throughput for the pipeline downstream of the amine plant.

UNITS: Percent (%)

DEFAULT: 0

Amine CO2 Input

This is the percentage of inlet gas volume entering an amine plant that consists of CO2. This value is provided in the Amine unit output displays.

UNITS: Percent (%)

DEFAULT: None

Amine CO2 Output

This is the percentage of outlet gas volume exiting an amine plant that consists of CO2. This value is provided in the Amine unit output displays.

UNITS: Percent (%)

DEFAULT: None

Amine H2S Input

This is the percentage of inlet gas volume entering an amine plant that consists of H2S. This value is provided in the Amine unit output displays.

UNITS: Percent (%)

DEFAULT: None

Amine H2S Output

This is the percentage of outlet gas volume exiting an amine plant that consists of H2S. This value is provided in the Amine unit output displays.

UNITS: Percent (%)

DEFAULT: None

Amine Plant Pressure Loss

The amine plant facility may cause a pressure drop. This value represents the pressure loss.

UNITS: psia (kPaa)

DEFAULT: 0

Pressure Loss Facilities

Pressure Loss Facilities can be used in a variety of situations where a fixed or variable pressure loss needs to be modeled. Some common applications of a pressure loss facility would to account for the existence of stagnant liquids in the pipeline, or the use of a choke or valve that is restricting flow.

Piper will model two types of pressure losses.

- Fixed Pressure Loss
- Variable Pressure Loss

Fixed Pressure Loss

A Fixed Pressure Loss would be used in a situation where the pressure loss can be assumed to be independent of flow conditions. A common example is when there are stagnant liquids that have accumulated in the pipeline.

The only input required for a fixed pressure loss is the value of that loss.

Variable Pressure Loss

A variable pressure loss uses the pressure loss at the first date the facility exists to determine pressure loss performance for subsequent months. A variable pressure loss uses the following equation to determine the pressure loss that follows.

$$q = k\sqrt{p_{outlet} \cdot \Delta p}$$

where:

q = gas flow rate

k = composite orifice flow factor (an arbitrary constant)

p_{outlet} = pressure at the outlet of the pressure loss facility

Δp = pressure loss across facility

This equation is a variation of the orifice-plate equation. When you select a variable pressure loss, you need to specify the rate, outlet pressure, and pressure loss that is experienced in the first month. These inputs are used to calculate a constant, and this constant is used in subsequent months to determine the pressure loss based on the outlet pressure and the flow rate.

Gathering System Map

This is a representation of the system that is visible on-screen and printable while in map mode. All active wells, links and units will be shown, usually in different colors denoting their function.

Delivery Point

The delivery point is the primary or starting node in a gathering system. It is also the final collection point for gas in a Piper modeled gathering system. All calculations are performed starting from the delivery point, solving outwards until all solutions converge.

Delivery Point Name

The delivery point name is the name given to the primary or starting node in a gathering system. The delivery point name defaults to “Delivery Point 1” but can be named virtually any combination of alphanumeric or numerical characters.

Note: the default delivery point name corresponds to the default node/facility naming convention defined in the Facility Name Generator. If the defaults that apply to how delivery points are named have been modified in this editor, the Delivery Point Name will follow the naming convention specified by the user.

The delivery point name can be changed after building a gathering system by simply changing the delivery point name in the Delivery Point Editor.

Note: the Delivery Point Name corresponds to the name that will be displayed on-screen to characterize a delivery point. The Node Name corresponding to each Delivery Point is the name that will be used in the Gathering System Editor to define the connectivity of each delivery point to the system. Should a Node Name change be required, use the node name changing procedure and the GIS Positions Editor (in Geodetic Mode) or the Node Editor (in Cartesian Mode).

UNITS: None

DEFAULT: Plant

Delivery Pressure

The delivery pressure is the pressure assigned to the outlet of the Delivery Point. This pressure can be scheduled through time to reflect seasonal delivery pressure variations or scheduled changes to compressor suction pressure. The default delivery point pressure of 900 psia should be revised immediately to reflect the delivery pressure of the system being modeled.

Inappropriate delivery point pressures can cause instabilities to the model's pressure loss calculations.

Note: When a compressor is placed at the Delivery Point, the delivery pressure will be the compressor discharge pressure.

UNITS: psia (kPaA)

DEFAULT: 900 psia (6205 kPaA)

Delivery Point Gas Rate

This refers to the total amount of gas flowing into the delivery point from all sources. It is usually measured in units of volume per unit time. In field units, or MMCFD (millions of cubic feet per day) per day are used. In metric units, m3 per day are used.

UNITS: MMCFD (m3)

DEFAULT: None

Delivery Point Liquid Rate

This refers to the total amount of liquid flowing into the delivery point from all sources. It is usually measured in units of volume per unit time. In field units, barrels per day are used. In metric units, m3 per day are used.

UNITS: bbl/d, m3/d

DEFAULT: None

Delivery Point Remarks

This field allows for the entry of delivery point specific remarks. These can be displayed on the gathering system map.

UNITS: None

DEFAULT: None

Line Pressure

This is the pressure in the transmission line leading from the wellhead. This usually is slightly lower than the wellhead pressure owing to pressure losses from surface equipment at or near the wellhead.

UNITS: psia (kPaa)

DEFAULT: 0

Pipeline ID

The Pipeline ID is the inside diameter of a pipeline segment called a Link in Piper. Commercial pipelines are generally specified based on approximate inside diameter measurements or nominal diameter. The inside diameter may be available directly from pipeline specifications or can be calculated from the outside diameter by subtracting twice the wall thickness. The wall thickness of several different pipelines having the same outside diameter can be very different, inside diameters depending on the grade and pressure rating of the line. The nominal diameter can be substituted only when specific dimensions are not available.

If no Pipeline ID is input for a Link (cell is left blank), then the program will not calculate any pressure losses for that link. This is a useful feature for spacing out lines for visual purposes without incurring any pressure losses in that link. Zero (0) is not a valid input for Pipeline ID. Use of zero (0) may cause the software to have a fatal error.

UNITS: Inches (mm)

DEFAULT: None

Pipeline Length

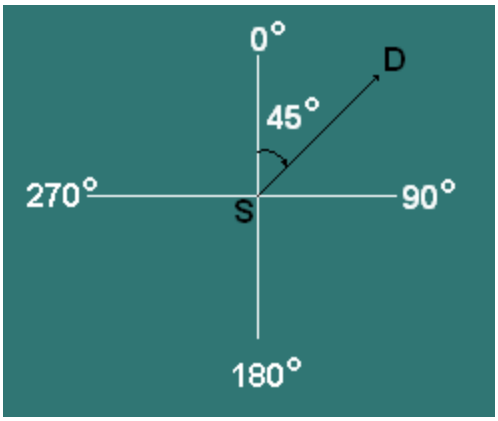
Pipeline Length is the length of a pipeline Link. A non-zero Pipeline length is required be input for any link containing a source name and/or destination name. Piper will scale all of the input pipeline lengths to fit the entire gathering system on-screen.

UNITS: miles (km) or ft (m)

DEFAULT: None

Direction Angle

Piper uses the mathematical concept of polar coordinates to describe a gathering system. In polar coordinates, the offset from the origin of a coordinate plot can be described using a distance and angle. Piper uses this concept to make building of the on-screen representation of a gathering model from a map as easy as possible. The idea is that the user can look at a map, "eyeball" the direction angle, and use the map's scaling to estimate the length of the pipeline segment. The direction angle is always measured from the positive "y" axis which is 0 degrees. Clockwise rotations are entered as positive angles . The following graphic provides a picture of this concept



UNITS: Degrees

DEFAULT: None

Elevation Change

This is the change in elevation that occurs between the Source Node and the Destination Node. The sign of the value indicates the direction of the elevation change relative to the Source Node. If the Source Node is above the Destination Node, the elevation difference is negative. If the Source Node is below the Destination Node, the elevation difference is positive. An easy way to visualize this is to imagine oneself as standing at the Source Node. If you are looking down at the Destination Node, then the elevation change will be a negative number. If you are looking up at the Destination Node, then the elevation change will be a positive number. When running the Panhandle (Original Piper), Piper ignores elevation change input data. As for all other single phase and multiphase correlations, Piper incorporated elevation change. In most cases, the elevation change that occurs between nodes due to a gas gradient is not sufficient to significantly affect the flowing pressure. If a large net elevation change is encountered such that significant pressure loses or gains may occur although the fluid is single-phase gas, then switch to the multi-phase correlation. This will trigger the hydro-static pressure loss calculation. When running the multi-phase correlation, Piper will use elevation change input data. If liquids are produced through a system and those liquids are being modeled, it is very important to account for all ups and downs in the system. If it is found that a link of pipeline in the model goes over a hill or through a valley, then that section should be broken into two links with the actual upward flow and downward flow sections modeled separately. If this rigorous approach creates numerous additional nodes, the model can be simplified somewhat by summing the up-flow sections only and entering that value as the elevation change. It is very important that looped lines or flow loop lines be modeled rigorously as flow direction can change depending upon many variables in the system.

Note: Flanigan and Modified Flanigan are not recommended in extreme elevation change (eg. 380ft or 100m).

UNITS: ft (m)

DEFAULT: 0

Pressure Loss Correlations

A fluid flowing in a wellbore will experience pressure losses. The pressure losses can be broken into 3 different components:

- hydrostatic pressure loss
- frictional pressure loss
- kinetic pressure loss

For wellbores, the kinetic losses are generally minimal and can be ignored. Thus, the equation that describes the overall pressure losses in the wellbore can be expressed as the sum of two terms:

$$\Delta P_{total} = \Delta P_{Hydro} + \Delta P_{Frictional}$$

The hydrostatic pressure losses are a function of the fluid mixture density that exists in the wellbore. The frictional losses are due to a combination of the particular flow regime that the fluid can be considered to be traveling in as well as the composition of the fluid (of gas, liquid and condensate).

Pressure Loss Calculation Procedure

(The phrases "pressure loss", "pressure drop" and "pressure difference" are used by different people, but mean the same thing).

In Piper, the pressure loss calculations for vertical, inclined or horizontal pipes follow the same procedure:

1. Total Pressure Loss = Hydrostatic Pressure Difference + Friction Pressure Loss. The total pressure loss, as well as each individual component can be either positive or negative, depending on the direction of calculation, the direction of flow and the direction of elevation change.
2. Subdivide the pipe length into segments so that the total pressure loss per segment is less than twenty (20) psi. Maximum number of segments is twenty (20).
3. For each segment assume constant fluid properties appropriate to the pressure and temperature of that segment.
4. Calculate the Total Pressure Loss in that segment as in step #1.
5. Knowing the pressure at the inlet of that segment, add to (or subtract from) it the Total Pressure Loss determined in step #4 to obtain the pressure at the outlet.
6. The outlet pressure from step #5 becomes the inlet pressure for the adjacent segment.

7. Repeat steps #3 to #6 until the full length of the pipe has been traversed.

Note: As discussed under Hydrostatic Pressure Difference and Friction Pressure Loss, the hydrostatic pressure difference is positive in the direction of the earth's gravitational pull, whereas the friction pressure loss is always positive in the direction of flow.

Correlations

There are a number of fluid correlation, derived empirically, that account for the hydrostatic and frictional fluid losses in a wellbore under a variety of flow conditions. The correlations that are included in Piper are as follows:

Single Phase - Wellbores and pipelines:

- Fanning Gas
- Panhandle
- Modified Panhandle
- Weymouth

Multiphase - Pipeline:

- Modified Beggs & Brill
- Petalas and Aziz
- Flanigan
- Modified Flanigan

Multiphase - Wellbore:

- Modified Beggs & Brill
- Gray
- Hagedorn & Brown

Single Phase Flow Theory

Single Phase Friction Component

There are two distinct types of correlations for calculating friction pressure loss (ΔP_f). The first type, adopted by the AGA (American Gas Association), includes Panhandle, Modified Panhandle and Weymouth. These correlations are for single-phase gas only. They incorporate a simplified friction factor and a flow efficiency. They all have a similar format as follows:

$$P_1 = \left\{ P_2^2 + \kappa \left(\frac{Q}{E} \right)^{\alpha} \left(\frac{P}{T} \right)^{\beta} \left(\frac{G^{\gamma}}{D^{\upsilon}} \right) T_a Z_a L \right\}^{1/2}$$

Where:

$P_1$and P_2 = upstream and downstream pressures respectively (psia)
Q = gas flow rate (@ T, P)
E = pipeline efficiency factor
P = reference pressure (psia) (14.65 psia)
T = reference temperature (°R) (520 °R)
G = gas gravity
D = inside diameter of pipe (in)
T_a= average flowing temperature (°R)
Z_a= average gas compressibility factor
L = pipe length (miles)
κ, α, β, γ, ν = constants

The other type of correlation is based on the definition of the friction factor (Moody or Fanning) and is given by the Fanning equation:

$$\Delta P_f = \frac{2 f \rho v^2 L}{g_c D}$$

Where:

ΔP_f= pressure loss due to friction effects (psia)
f = Fanning friction factor (function of Reynolds number)
ρ = density (lb_m/ft^3)
v = average velocity (ft/s)
L = length of pipe section (ft)
g_c= gravitational constant (32.174 $lb_m ft/lb_f s^2$)
D = inside diameter of pipe (ft)

This correlation can be used either for single-phase gas (Fanning Gas) or for single-phase liquid (Fanning Liquid).

Single-Phase Friction Factor (f):

The single-phase friction factor can be obtained from the Chen (1979) equation, which is representative of the Fanning friction factor chart.

$$\frac{1}{\sqrt{f}} = -4.0\log\left[0.2698\left(\frac{k}{D}\right) - \frac{5.0452}{\mathrm{Re}}\log\left\{0.3539\left(\frac{k}{D}\right)^{1.1098} + \frac{5.8506}{\mathrm{Re}^{0.8981}}\right\}\right]$$

Where:

f = friction factor
k = absolute roughness (in)
k/D = relative roughness (unitless)
Re = Reynold's number

The single-phase friction factor clearly depends on the Reynold's number, which is a function of the fluid density, viscosity, velocity and pipe diameter. The friction factor is valid for single-phase gas or liquid flow, as their very different properties are taken into account in the definition of Reynold's number.

$$\mathrm{Re} = \frac{\rho V D}{\mu}$$

Where:

ρ = density (lb_m/ft^3)
v = velocity (ft/s)
D = diameter (ft)
μ = viscosity (lb/ft*s)

Since viscosity is usually measured in "centipoise", and 1 cp = 1488 lb/ft*s, the Reynolds number can be rewritten for viscosity in centipoise.

$$\mathrm{Re} = \frac{1488\,\rho V D}{\mu}$$

References: Chen, N. H., "An Explicit Equation for Friction Factor in Pipe," Ind. Eng. Chem. Fund. (1979).

Single Phase Hydrostatic Component

Hydrostatic pressure difference (ΔP_{HH}) can be applied to all correlations by simply adding it to the friction component. The hydrostatic pressure drop (ΔP_{HH}) is defined, for all situations, as follows:

$$\Delta P_{HH} = \rho g h$$

Where:

ρ = density of the fluid
g = acceleration of gravity
h = vertical elevation (can be positive or negative)

For a liquid, the density (ρ) is constant, and the above equation is easily evaluated.

For a gas, the density varies with pressure. Therefore, to evaluate the hydrostatic pressure loss/-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. Notethat this is equivalent to a **multi-step Cullender and Smith** calculation.

Single Phase Flow Correlations

There exist many single-phase correlations that were derived for different operating conditions or from laboratory experiments. Generally speaking, they only account for the friction component, i.e. they are applicable to horizontal flow. Typical examples are:

- Fanning Gas
- Fanning Liquid
- Panhandle
- Modified Panhandle
- Weymouth

There are several single-phase correlations that are available:

- Fanning – the Fanning correlation is divided into two sub categories Fanning Liquid and Fanning Gas. The Fanning Gas correlation is also known as the Multi-step Cullender and Smith when applied for vertical wellbores.
- Panhandle – the Panhandle correlation was developed originally for single-phase flow of gas through horizontal pipes. In other words, the hydrostatic pressure difference is not taken into account. We have applied the standard hydrostatic head equation to the vertical elevation of the pipe to account for the vertical component of pressure drop. Thus our implementation of the Panhandle equation includes BOTH horizontal and vertical flow components, and this equation can be used for horizontal, uphill and downhill flow.
- Modified Panhandle – the Modified Panhandle correlation is a variation of the Panhandle correlation that was found to be better suited to some transportation systems. Thus, it also originally did not account for vertical flow. We have applied the standard hydrostatic head equation to account for the vertical component of pressure drop. Hence our implementation of the Modified Panhandle equation includes BOTH hori-

zontal and vertical flow components, and this equation can be used for horizontal, uphill and downhill flow.

- Weymouth – the Weymouth correlation is of the same form as the Panhandle and the Modified Panhandle equations. It was originally developed for short pipelines and gathering systems. As a result, it only accounts for horizontal flow and not for hydrostatic pressure drop. We have applied the standard hydrostatic head equation to account for the vertical component of pressure drop. Thus, our implementation of the Weymouth equation includes BOTH horizontal and vertical flow components, and this equation can be used for horizontal, uphill and downhill flow.

In Piper, for cases that involve a single phase, the Gray, the Hagedorn and Brown, the Beggs and Brill and the Petalas and Aziz correlations 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 would be used. For cases where there is a single phase, the Flanigan and Modified Flanigan correlations devolve to the single-phase Panhandle and Modified Panhandle correlations respectively. The Weymouth (Multiphase) correlation devolves to the single-phase Weymouth correlation.

The single-phase correlations can be used for vertical or inclined flow, provided 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 that correlation to be used for flow in a vertical pipe. This adaptation is rigorous, and has been implemented into all the correlations used in Piper. Nevertheless, for identification purposes, the correlation's name has been kept unchanged. Thus, for example, Panhandle was originally developed for horizontal flow, but its implementation in this program allows it to be used for all directions of flow, and it is referred to as Panhandle when applied to both pipelines and wellbores.

Multiphase Flow Theory

Multiphase pressure loss calculations parallel single phase pressure loss calculations. Essentially, each multiphase correlation makes its own particular 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 have to 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, all 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 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. In the AGA type equations (Panhandle, Modified Panhandle and Weymouth), it is the flow efficiency that is modified.

The hydrostatic pressure difference calculation is modified by defining a mixture density. This is determined by a calculation of in-situ liquid holdup. Some correlations determine holdup based on defined flow patterns.

The multiphase pressure loss correlations used in this software are of three types.

- The first type (Flanigan, Modified Flanigan) is based on a combination of the AGA equations for gas flow in pipelines and the Flanigan multiphase corrections. These equations can be used for gas-liquid multiphase flow or for single-phase gas flow. They CANNOT be used for single-phase liquid flow.

Note: These two correlations can give erroneous results if the pipe described deviates substantially (more than 10 degrees) from the horizontal.

- The second type (Beggs and Brill, Hagedorn and Brown, Gray) is the set of correlations based on the Fanning friction pressure loss equation. These can be used for gas-liquid multiphase flow, single-phase gas or single-phase liquid, because in single-phase mode, they revert to the Fanning equation, which is equally applicable to either gas or liquid. Beggs and Brill is a multi-purpose correlation derived from laboratory data for vertical, horizontal, inclined uphill and downhill flow of gas-water mixtures. Gray is based on field data for vertical gas wells producing condensate and water. Hagedorn and Brown was derived from field data for flowing vertical oil wells.

Note: The Gray and Hagedorn and Brown correlations were derived for vertical wells and may not apply to horizontal pipes.

- The third type (Petalas and Aziz) is a mechanistic model combined with empirical correlations. This model can be used for gas-liquid multiphase flow, single-phase gas or single-phase liquid, because in single-phase mode, it reverts back to the Fanning Equations, which is equally applicable to either gas or liquid. Petalas and Aziz is a multi-purpose correlation that is applicable for all pipe geometries, inclinations and fluid properties.

Multiphase Friction Component

In pipe flow, the friction pressure loss is the component of pressure loss caused by viscous shear effects. The friction pressure loss is ALWAYS positive IN THE DIRECTION OF FLOW. It is combined with the hydrostatic pressure difference (which may be positive or negative depending on the whether the flow is uphill or downhill) to give the total pressure loss.

The friction pressure loss is calculated from the Fanning friction factor equation as follows:

$$\Delta P_f = \frac{2fpv^2L}{gD}$$

Where:

ΔP_f= pressure loss due to friction
f = Fanning friction factor
ρ = in-situ density
V^2= the square of the in-situ velocity
L = length of pipe segment
g = acceleration of gravity
D = pipe internal diameter

In the above equation, the variables f, ρ and V^2require special discussion, as follows:

$$Re = \frac{\rho VD}{\mu}$$

Where:

ρ = density
V = velocity
D = diameter
μ = viscosity

Multiphase Friction Factor ():

This is obtained from multi-phase flow correlations (see Beggs and Brill under multiphase flow). This correlation depends, in part, on the gas and liquid flow rates, but also on the standard Fanning (single phase) friction factor charts. When evaluating the Fanning friction factor, there are many ways of calculating the Reynold's number depending on how the density, viscosity and velocity of the two-phase mixture are defined. For the Beggs and Brill calculation of Reynold's number, these mixture properties 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.

Multiphase Hydrostatic Component

The 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, irrespective of what sign convention is used, the contribution of the hydrostatic pressure calculation must be such that it will tend to make the pressure at the vertically-lower end higher than that at the upper end.

The hydrostatic pressure difference is calculated as follows:

$$\Delta P_{HH} = \frac{g}{g_c} \rho \Delta z$$

Where:

ΔP_{HH}= the hydrostatic pressure difference
Δz = the vertical elevation change
ρ = the in-situ density of the fluid or mixture
g = acceleration of gravity
g_c= conversion factor

In the equation above, the problem is really determining an appropriate value for ρ (rho), as discussed below:

For a single phase liquid, this is easy, and ρ equals the liquid density.

For a single phase gas, ρ varies with pressure, and the calculation must be done sequentially in small steps to allow the density to vary with pressure.

For multi-phase flow, ρ is calculated from the in-situ mixture density, which in turn is calculated from the "liquid holdup". The liquid holdup is obtained from multi-phase flow correlations, such as Beggs and Brill, and depends on the gas and liquid rates, pipe diameter, etc...

For a horizontal pipe segment, $\Delta z = 0$, and there is NO hydrostatic pressure loss.

Multiphase Friction Factor ():

The multiphase friction factor can be obtained from multiphase flow correlations. These correlations depend, in part, on the gas and liquid flow rates, but also on the standard Fanning (single phase) friction factor charts. When evaluating the friction factor, there are many ways of calculating the Reynold's number depending on how the density, viscosity and velocity of the two-phase mixture are defined. The Reynolds Number used to calculate the multiphase friction factor may indeed vary with each correlation. The Reynolds Number is dimensionless and is defined as:

$$Re = \frac{\rho V D}{\mu}$$

Where:

ρ = density (lb_m/ft^3)
v = velocity (ft/s)
D = diameter (ft)
μ = viscosity (lb/ft*s)

Since viscosity is usually measured in "centipoise", and 1 cp = 1488 lb/ft*s, the Reynolds number can be rewritten for viscosity in centipoise.

$$Re = \frac{1488\,\rho V D}{\mu}$$

Density

Density (ρ) as applied to 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_1 is simply the liquid density.
- For a single-phase gas, $\rho_1$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.
- For multiphase flow, the calculations become even more complicated because ρ_1 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 it 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 the friction pressure loss.

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:

$$V_{sl} = \frac{Q_L}{\pi/4 D^2}$$

and

$$V_{sg} = \frac{Q_G B_g}{\pi/4 D^2}$$

Where:

B_g = gas formation volume factor
D = inside diameter of pipe
Q_G = measured gas flow rate (at standard conditions)
Q_L = liquid flow rate (at prevailing pressure and temperature)
V_{sg} = superficial gas velocity
V_{sl} = superficial liquid velocity

Since the liquid phase accounts for both oil and water ($Q_L = Q_0 B_0 + (QW - WC * Q_G) B_W$) and the gas phase accounts for the solution gas going in and out of the oil as a function of pressure ($Q_G = Q_G - Q_0 R_s$), the superficial velocities can be rewritten as:

$$V_{sl} = \frac{Q_o B_o + (Q_w - WC * Q_G) B_w}{\pi/4 D^2}$$

$$V_{sg} = \frac{(Q_G - Q_o R_s) B_g}{\pi/4 D^2}$$

Where:

Q_O = oil flow rate (at stock tank conditions)
Q_W = water flow rate in (at stock tank conditions)
Q_G = gas flow rate (at standard conditions of 14.65psia and 60F)
Q_L = liquid flow rate (oil and water at prevailing pressure and temperature)
B_O = oil formation volume factor
B_W = water formation volume factor
B_g = gas formation volume factor
R_S = solution gas/oil ratio
WC = water of condensation (water content of natural gas, Bbl/MMscf)

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.

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 the phase. Usually the phase that is less dense will flow faster than the other. This causes a "slip" or holdup effect, which means that the in-situ volume fractions of each phase (under flowing conditions) will differ from the input volume fractions of the pipe.

In-Situ Volume Fraction (Liquid Holdup)

The in-situ volume fraction, E_L(or H_L), is often the value that is estimated by multiphase correlations. Because of "slip" between phases, the "holdup" (E_L) can be significantly different from the input liquid fraction (C_L– lb/ft). For example, a single-phase gas can percolate through a wellbore containing water. In this situation C_L= 0 (single-phase gas is being produced), but E_L> 0 (the wellbore contains water). The in-situ volume fraction is defined as follows:

$$E_L = \frac{A_L}{A}$$

Where:

A_L = cross-sectional area occupied by the liquid phase
A = total cross-sectional area of the pipe

Input Volume Fraction

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 this as:

$$C_L = \frac{V_{sl}}{V_m}$$

$$C_G = \frac{V_{sg}}{V_m}$$

Where:

B_g = gas formation volume factor
C_G = input gas volume fraction
C_L = input liquid volume fraction
Q_G = gas flow rate (at standard conditions)
Q_L = liquid flow rate (at prevailing pressure and temperature)
V_{sg} = superficial gas velocity
V_{sl} = superficial liquid velocity
V_m = mixture velocity (V_{sl}+ V_{sg})

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.

Mixture Velocity

Mixture Velocity is another parameter often used in multiphase flow correlations. The mixture velocity is given by:

$$V_m = V_{sl} + V_{sg}$$

Where:

V_{m-}= mixture velocity
V_{sl} = superficial liquid velocity
V_{sg} = superficial gas velocity

Mixture Viscosity

The 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.

$$\begin{aligned}\mu_m &= \mu_L E_L + \mu_G E_G \\ &= \mu_L E_L + \mu_G (1 - E_L)\end{aligned}$$

Where:

E_L = in-situ liquid volume fraction (liquid holdup)
E_G = in-situ gas volume fraction
μ_m = mixture viscosity
μ_L = liquid viscosity
μ_{G-}= gas viscosity

Note: The mixture viscosity is defined in terms of in-situ volume fractions (E_L), whereas the no-slip viscosity is defined in terms of input volume fractions (C_L).

Mixture Density

The mixture density is a measure of the in-situ density of the mixture, and is defined as follows:

$$\begin{aligned}\rho_m &= \rho_L E_L + \rho_G E_G \\ &= \rho_L E_L + \rho_G (1 - E_L)\end{aligned}$$

Where:

E_L = in-situ liquid volume fraction (liquid holdup)
E_G = in-situ gas volume fraction
ρ_m = mixture density
ρ_L = liquid density
ρ_G = gas density

Note: The mixture density is defined in terms of in-situ volume fractions (E_L), whereas the no-slip density is defined in terms of input volume fractions (C_L).

No-Slip Density

The "no-slip" density is the density that is calculated with the assumption that both phases are moving at the same in-situ velocity. The no-slip density is therefore defined as follows:

$$\rho_{NS} = \rho_L C_L + \rho_G C_G$$
$$= \rho_L C_L + \rho_G (1 - C_L)$$

Where:

C_L = input liquid volume fraction
C_G = input gas volume fraction
ρ_{NS} = no-slip density
ρ_L = liquid density
ρ_G = gas density

Note: The no-slip density is defined in terms of input volume fractions (C_L), whereas the mixture density is defined in terms of in-situ volume fractions (E_L).

No-Slip Viscosity

The "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:

$$\mu_{NS} = \mu_L C_L + \mu_G C_G$$
$$= \mu_L C_L + \mu_G (1 - C_L)$$

Where:

C_L = input liquid volume fraction
C_G = input gas volume fraction
μ_{NS} = no-slip viscosity

μ_L = liquid viscosity
μ_G = gas viscosity

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 use in 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[1], Hough[2] and by Beggs[3].

Gas/Oil Interfacial Tension

The dead oil interfacial tension at temperatures of 68°F and 100°F is given by:

$$\sigma_{68} = 39 - 0.2571(API)$$

$$\sigma_{100} = 37.5 - 0.2571(API)$$

Where

σ_{68} = interfacial tension at 68°F (dynes/cm)
σ_{100} = interfacial tension at 100°F (dynes/cm)
API = gravity of stock tank oil (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.

$$C = 1.0 - 0.024p^{0.45}$$

Where:

p = pressure (psia)

The interfacial tension becomes zero at miscibility pressure, and for most systems this will be at any pressure greater than about 5000 psia. Once 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:

$$\sigma_{w(74)} = 75 - 1.108p^{0.349}$$

$$\sigma_{w(280)} = 53 - 0.1048p^{0.637}$$

Where:

$\sigma_{W(74)}$ = interfacial tension at 74°F (dynes/cm)
$\sigma_{W(280)}$ = interfacial tension at 280°F (dynes/cm)
p = pressure (psia)

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.

Multiphase 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. The following is a list of the multiphase flow correlations that are available.

1. Gray: The Gray Correlation (1978) was 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: The Hagedorn and Brown Correlation (1964) was developed for vertical flow in oil wells. We have also 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.

2. Beggs and Brill: The Beggs and Brill Correlation (1973) is 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.

3. Flanigan: The Flanigan Correlation (1958) is an extension of the Panhandle single-phase correlation to multiphase flow. It incorporates a correction for downhill flow. In this software,

the Flanigan multiphase correlation is also applied to the Modified Panhandle and Weymouth correlations. It is recommended that this correlation not be used beyond +/- 10 degrees from the horizontal.

4. Modified-Flanigan: The Modified Flanigan Correlation is an extension of the Modified Panhandle single-phase equation to multiphase flow. It incorporates the Flanigan correction of the Flow Efficiency for multiphase flow and a calculation of hydrostatic pressure difference to account for uphill flow. There is no hydrostatic pressure recovery for downhill flow. In this software, the Flanigan multiphase correlation is also applied to the Panhandle and Weymouth correlations. It is recommended that this correlation not be used beyond +/- 10 degrees from the horizontal.

5. Petalas and Aziz: The Petalas and Aziz Model (2000) is a correlation that was 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 (fundamental laws) are combined with empirical closure relationships to provide a model that is more robust than other models and can be to used 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 will 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-phased flow, these four correlations devolve to the Fanning Gas or Fanning Liquid correlation.

When switching from multiphase flow to single-phase flow, the correlation will default to Fanning. When switching from single-phase to multiphase flow, the correlation will default to Beggs and Brill.

Important Notes:

- The Flanigan, Modified-Flanigan and Weymouth (Multiphase) correlations can give erroneous results if the pipe described deviates substantially (more than 10 degrees) from the horizontal. The Gray and Hagedorn and Brown correlations were derived for vertical wells and may not apply to horizontal pipes.
- In Piper, the Gray, the Hagedorn and Brown and the Beggs and Brill correlations revert to the appropriate single-phase Fanning correlation (Fanning Liquid or Fanning Gas. The Flannigan and Modified-Flanigan revert to the Panhandle, Modified Panhandle and Weymouth respectively.

Beggs and Brill Correlation

For multiphase flow, many of the published correlations are applicable for "vertical flow" only, while others apply for "horizontal flow" only. Few correlations apply to the whole spectrum of flow

situations that may be encountered in oil and gas operations, namely uphill, downhill, horizontal, inclined and vertical flow. The Beggs and Brill (1973) correlation, is one of the few published correlations capable of handling all these flow directions. It was developed using 1" and 1-1/2" sections of pipe that could be inclined at any angle from the horizontal.

The Beggs and Brill multiphase correlation deals with both the friction pressure loss and the hydrostatic pressure difference. First the appropriate flow regime 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 appropriate flow regime, 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 the friction pressure loss is calculated using "input" gas-liquid mixture properties. A more detailed discussion of each step is given in the following documentation.

If only a single-phase fluid is flowing, the Beggs and Brill multiphase correlation devolves to the Fanning Gas or Fanning Liquid correlation.

Flow Pattern Map

Unlike the Gray or the Hagedorn and Brown correlations, the Beggs and Brill correlation requires that a flow pattern be determined. Since the original flow pattern map was created, it has been modified. We have used this modified flow pattern map for our calculations. The transition lines for the modified correlation are defined as follows:

$$L_1^* = 316\, C_L^{0.302}$$
$$L_2^* = 0.0009252\, C_L^{-2.4684}$$
$$L_3^* = 0.1\, C_L^{-1.4516}$$
$$L_4^* = 0.5\, C_L^{-6.738}$$

The flow type can then be readily determined either from a representative flow pattern map or according to the following conditions, where

$$Fr_m = \frac{V_m^2}{gD}$$

SEGREGATED flow

if

$C_L < 0.01$ and $Fr_m < L_1^*$

or

$C_L \geq 0.01$ and $Fr_m < L_2^*$

INTERMITTENT flow

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 flow

if

$C_L < 0.4$ and $Fr_m \geq L_4^*$

or

$C_L \geq 0.4$ and $Fr_m > L_4^*$

TRANSITION flow

if and

$L_2^* < Fr_m < L_3^*$

Hydrostatic Pressure Difference

Once the flow type has been determined then the liquid holdup can be calculated. Beggs and Brill divided the liquid holdup calculation into two parts. First the liquid holdup for horizontal flow, $E_L(0)$, is determined, and then this holdup is modified for inclined flow. $E_L(0)$ must be ≥ C_L and therefore when $E_L(0)$ is smaller than C_L, $E_L(0)$ is assigned a value of C_L. There is a separate calculation of liquid holdup ($E_L(0)$) for each flow type.

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

$$E_L(0)=\frac{1.065\ C_L^{0.5824}}{Fr_m^{0.0609}}$$

IV. TRANSITION

$$E_L(0)_{transition} = AE_L(0)_{segregated} + BE_L(0)_{intermittent}$$

Where:

$$A=\frac{L_3^* - Fr_m}{L_3^* - L_2^*} \quad \text{and} \quad B=1-A$$

Once the horizontal in situ liquid volume fraction is determined, the actual liquid volume fraction is obtained by multiplying $E_L(0)$ by an inclination factor, $B(\theta)$. i.e.

$$E_L(\theta) = B(\theta) \times E_L(0)$$

Where:

$$B(\theta)=1+\beta\left[\sin(1.8\,\theta) - \frac{1}{3}\sin^3(1.8\,\theta)\right]$$

β is a function of flow type, the direction of inclination of the pipe (uphill flow or downhill flow), the liquid velocity number (N_{vl}), and the mixture Froude Number (Fr_m).

The liquid velocity number (N_{vl}) is defined as:

$$N_{vl} = 1.938\, V_{sl} \left(\frac{\rho_L}{g\,\sigma}\right)^{1/4}$$

For **UPHILL** flow:

SEGREGATED

$$\beta = (1 - C_L) \ln\left[\frac{0.011\, N_{vl}^{3.539}}{C_L^{3.768}\, Fr_m^{1.614}}\right]$$

INTERMITTENT

$$\beta = (1 - C_L) \ln\left[\frac{2.96 C_L^{0.305}\, Fr_m^{0.0978}}{N_{vl}^{0.4473}}\right]$$

DISTRIBUTED

$$\beta = 0$$

For **DOWNHILL** flow:

I, II, III. ALL flow types

$$\beta = (1 - C_L) \ln\left[\frac{4.70\, N_{vl}^{0.1244}}{C_L^{0.3692}\, Fr_m^{0.5056}}\right]$$

Note: β must always be ≥ 0. Therefore, if a negative value is calculated for β, β = 0.

Once the liquid holdup ($E_L(\theta)$) is calculated, it is used to calculate the mixture density (ρ_m). The mixture density is, in turn, used to calculate the pressure change due to the hydrostatic head of the vertical component of the pipe or well.

$$\Delta P_{HH} = \frac{\rho_m g \Delta z}{144\, g_c}$$

Friction Pressure Loss

The first step to calculating the pressure drop due to friction is to calculate the empirical parameter S. The value of S is governed by the following conditions:

if 1 < y < 1.2, then

$$S = \ln(2.2y - 1.2)$$

otherwise,

$$S = \frac{y}{-0.0523 + 3.18y - 0.872y^2 + 0.01853y^4}$$

where:

$$y = \ln \frac{C_L}{E_L^2}$$

Note: Severe instabilities have been observed when these equations are used as published. Our implementation has modified them so that the instabilities have been eliminated.

A ratio of friction factors is then defined as follows:

$$\frac{f_{tp}}{f_{NS}} = e^S$$

$$\therefore f_{tp} = f_{NS} e^S$$

f_{NS} is the no-slip friction factor. We use the Fanning friction factor, calculated using the Chen equation. The no-slip Reynolds Number is also used, and it is defined as follows:

$$Re_{NS} = \frac{\rho_{NS} V_m D}{\mu_{NS}}$$

Finally, the expression for the pressure loss due to friction is:

$$\Delta P_f = \frac{2 f_{tp} V_m^2 \rho_{NS} L}{144 g_c D}$$

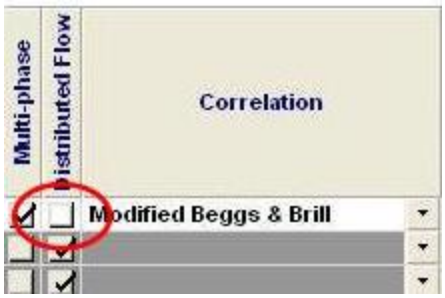
Nomenclature

C_L = liquid input volume fraction
D = inside pipe diameter (ft)
$E_L(0)$ = horizontal liquid holdup
$E_L(\theta)$ = inclined liquid holdup
f_{tp} = two phase friction factor
f_{NS} = no-slip friction factor
Fr_m = Froude Mixture Number
g = gravitational acceleration (32.2 ft/s^2)
g_c = conversion factor (32.2 $(lb_m*ft)/(lb_f*s^2)$)
L = length of pipe (ft)
N_{vl} = liquid velocity number
V_m = mixture velocity (ft/s)
V_{sl} = superficial liquid velocity (ft/s)
ΔZ = elevation change (ft)
μ_{NS} = no-slip viscosity (cp)
θ = angle of inclination from the horizontal (degrees)
ρ_L = liquid density (lb/ft^3)
ρ_{NS} = no-slip density (lb/ft^3)
ρ_m = mixture density (lb/ft^3)
σ = gas/liquid surface tension (dynes/cm)

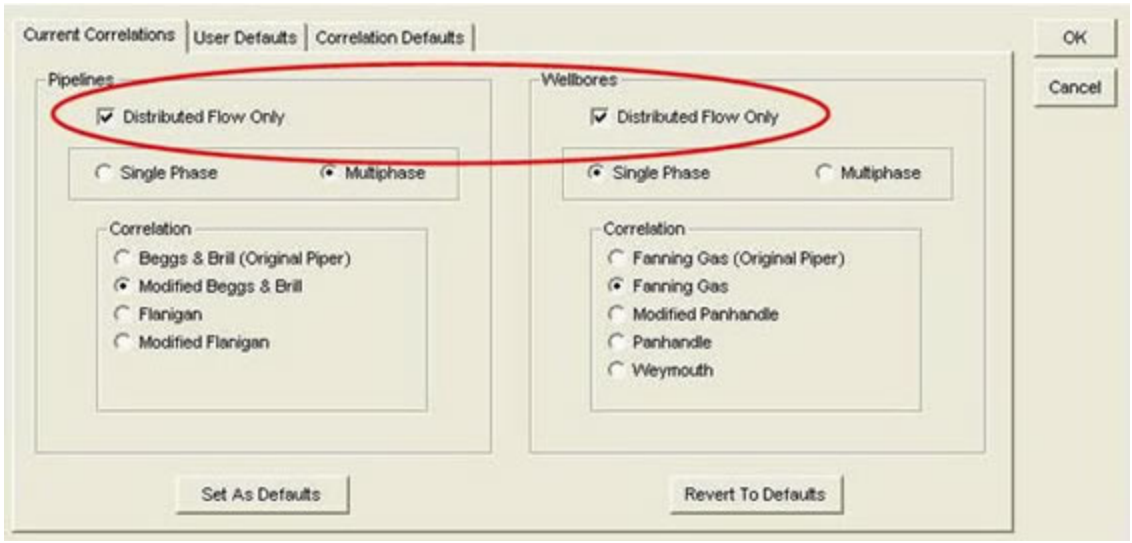
Distributed Flow Flag for Beggs and Brill Correlations

The Distributed Flow Flag in Piper is used when the Beggs and Brill or Modified Beggs and Brill correlation is selected.

The distributed flow flag is found on a well by well basis in the Wellbore Tuning menu:



It is also found as a general correlation default in the Pressure Loss Correlations menu:



Both Beggs and Brills correlations calculate the pressure drop across the pipe segment by first determining the flow regime that the fluid is flowing in. The flow can exist in one of three regimes.

- Distributed Flow
- Intermittent Flow
- Segregated Flow

By turning on the Distributed Flow flag, Piper will overrule the flow regime naturally determined by the Beggs and Brill correlation and force distributed flow in the segment.

Piper allows for this option to prevent against multiple solutions. It is used primarily in wellbores. The Beggs and Brill correlation, applied to vertical wellbore flow, will in some cases predict increasing pressure drops with decreasing gas flows as the segregated and intermittent flow regimes increase liquid hold-up in the wellbore . This scenario can result in wellhead deliverability curves where for some pressures, multiple deliverability solutions exist.

To prevent against multiple solutions, Piper will not allow a well to flow outside of the distributed flow regime. When the Beggs and Brill flow regime is intermittent or segregated, a message will be returned, alerting the user that 'the well is susceptible to liquid loading and has been shut-in'.



Forcing distributed flow by checking the distributed flow tab is an alternative that will allow the well to flow even outside of the distributed flow regime.

References

Beggs, H. D., and Brill, J.P., "A Study of Two-Phase Flow in Inclined Pipes," JPT, 607-617, May 1973. Source: JPT.

Petalas and Aziz Correlation

For multiphase flow, many of the published correlations are applicable for "vertical flow" only, while others apply for "horizontal flow" only. Few correlations apply to the whole spectrum of flow situations that may be encountered in oil and gas operations, namely uphill, downhill, horizontal, inclined and vertical flow. The Petalas and Aziz (2000) correlation is capable of handling flow in all directions. It was developed using a mechanistic approach (based on fundamental laws) and combined with empirical correlations. Petalas and Aziz deemed some of the available correlations for multiphase flow inadequate to use in their model and developed new correlations using experimental data from Standford University’s Multiphase Flow Database. The information in this database allowed for a more detailed investigation of annular-mist, stratified and intermittent flow regimes.

The Petalas and Aziz multiphase correlation accounts for both frictional pressure loss and hydrostatic pressure differences. Initially, a flow pattern is determined by comparing the gas and liquid superficial velocities to the stability criteria (flow regime boundaries) dictated by the mechanistic model. Each particular combination of gas and liquid rates are characterized by the following flow regimes:

- Dispersed Bubble Flow
- Stratified Flow
- Annular-mist Flow
- Bubble Flow
- Intermittent Flow

The liquid volume fraction and therefore the in-situ gas-liquid mixture densities are then calculated according to the appropriate flow distribution to obtain the hydrostatic pressure component of the pressure gradient. A friction factor is obtained for each flow regime by standard methods using pipe

roughness and a Reynold's number defined specifically for each flow type. A more detailed discussion of the calculations for this multiphase flow correlation are outlined in the sections below.

If only a single-phase fluid is flowing, the Petalas and Aziz multiphase correlation devolves to the Fanning Gas or Fanning Liquid correlation.

Flow Pattern Determination

The Petalas and Aziz model for multiphase flow requires that a flow pattern be determined. Transition between flow regimes are based on superficial velocities of the phases and bounded by stability criteria characterized by this mechanistic model. Five flow patterns are defined in this model and the transition zones for this correlation are given below:

DISPERSED BUBBLE FLOW

Dispersed bubble flow exists if:

$$E_{Ls} > 0.48$$

And if:

$$C_G = \frac{V_{SG}}{V_m} \leq 0.52$$

STRATIFIED FLOW

- Calculate the dimensionless liquid height ($\tilde{h}_L$)

Use momentum balance equations for gas and liquid phases:

$$-A_L\left(\frac{dp}{dL}\right)-\tau_{wL}S_L+\tau_i S_i-\rho_L A_L\frac{g}{g_c}\sin\theta=0 \quad -A_G\left(\frac{dp}{dL}\right)-\tau_{wG}S_G+\tau_i S_i-\rho_G A_G\frac{g}{g_c}\sin\theta=0$$

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:

$$V_L > \sqrt{\frac{gD(1-\tilde{h}_L)\cos\theta}{f_L}}$$

(**Note**: When cosθ ≤ 0.02, cosθ =0.02)

To distinguish between stratified smooth and stratified wavy flow regimes:

Stratified smooth flow exists if:

$$V_G \leq \sqrt{\frac{4\mu_L(\rho_L-\rho_G)g\cos\theta}{s\rho_L\rho_G V_L}} \quad \text{where } s = 0.06$$

And if:

$$Fr = \frac{V_L}{\sqrt{gh_L}} > 1.4$$

ANNULAR-MIST FLOW

- Calculate the dimensionless liquid film thickness ($\tilde{\delta}_L$)

Use momentum balance on the liquid film and gas core with liquid droplets:

$$-A_f\left(\frac{dp}{dL}\right)-\tau_{wL}S_L+\tau_i S_i-\rho_L A_L\frac{g}{g_c}\sin\theta=0$$

$$-A_c\left(\frac{dp}{dL}\right)-\tau_i S_i-\rho_c A_c\frac{g}{g_c}\sin\theta=0$$

Annular-mist flow exists if:

$$\tilde{\delta}_L < \tilde{\delta}_{L\,min}$$

Where $\tilde{\delta}_{L\,min}$ is determined from the following equations:

$$2f_f \frac{\rho_L}{\rho_L - \rho_c} \frac{V_{SL}^2 (1-FE)^2}{g\, D \sin\theta} = \frac{E_f^3 \left(1-\frac{3}{2}E_f\right)}{2-\frac{3}{2}E_f}$$

$$E_f = \frac{A_f}{A} = 4\tilde{\delta}_L \left(1-\tilde{\delta}_L\right)$$

Solve for $\tilde{\delta}_{L\,min}$ iteratively.

And if:

$$E_L \leq 0.24$$

BUBBLE FLOW

Bubble flow exists if:

$$D > 19 \left[\frac{(\rho_L - \rho_G)\sigma}{\rho_L^2\, g}\right]^{\frac{1}{2}}$$

And if:

$$\cos\theta \leq \frac{3}{4\sqrt{2}} V_b^2 \left(\frac{C_1\, \gamma^2}{g\, d_b}\right)$$

Where:

$C_1 = 0.8$
$\gamma = 1.3$
$d_b = 7\text{mm}$

$$V_b = 1.41 \left[\frac{g(\rho_L - \rho_G)\sigma}{\rho_L^2}\right]^{\frac{1}{4}} \sin\theta$$

Also, transition to bubble flow from intermittent flow occurs when:

$$E_L > 0.25$$

Where:

$$E_L = \frac{E_{Ls}V_t + V_{Gdb}(1-E_{Ls}) - V_{SG}}{V_t}$$

(**Note**: Additional definitions are given in the Intermittent Flow section.)

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:

$$E_L = \frac{E_{Ls}V_t + V_{Gdb}(1-E_{Ls}) - V_{SG}}{V_t}$$

(Note: If $E_L > 1$, then $E_L = C_L$)

And if:

$$E_{Ls} = \frac{1}{1+\left(\frac{V_m}{8.66}\right)^{1.39}}$$

Where:

$$V_m = V_{SG} + V_{SL}$$

If $E_L > 0.24$ and $E_{Ls} < 0.9$ then Slug Flow
If $E_L > 0.24$ and $E_{Ls} > 0.9$ the 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.

Hydrostatic Pressure Difference

Once the flow type has been determined then the liquid holdup can be calculated. There is a separate calculation of liquid holdup (E_L) for each flow type.

DISPERSED BUBBLE FLOW

The calculation of liquid volume fraction for dispersed bubble flow uses the same procedure for calculating the dispersed bubbles in the slug in intermittent flow (see intermittent flow for additional details).

$$V_{Gdb}=C_0 V_m+V_b$$

Where C_0 is determined from the empirical correlation:

$$C_0=(1.64+0.12\sin\theta)Re_{mL}^{-0.031}$$

$$Re_{mL}=\frac{\rho_L V_m D}{\mu_L}$$

And V_b (the rise velocity of the dispersed bubbles) determined from:

$$V_b=1.53\left[\frac{g\,(\rho_L-\rho_G)\,\sigma}{\rho_L^2}\right]^{1/4}\sin\theta$$

Now, E_L is given by:

$$E_L=1-\frac{V_{SG}}{V_{Gdb}}$$

If $V_{Gdb} \leq 0$, then E_L is given by:

$$E_L=1-\frac{V_{SG}}{C_0 V_m}$$

Note: If E_L is calculated to be great than 1.0, the E_L is set equal to C_L.

Once the liquid holdup (E_L) has been calculated, it is then used to calculate the mixture density (ρ_m). The mixture density can now be used to calculate the pressure change due to the hydrostatic head for the segment of pipe being investigated.

$$\Delta P_{HH}=\rho_m\frac{g}{g_c}\sin\theta$$

STRATIFIED FLOW

Liquid volume fraction (E_L) is given by:

$$E_L = \frac{A_L}{A_I}$$

The ΔP_{HH} is then calculated from the hydrostatic portion of the gas and liquid phase momentum balance equations.

Where:

$$\Delta P_{HH} = \rho_L \frac{g}{g_c} \sin\theta$$

$$\Delta P_{HH} = \rho_G \frac{g}{g_c} \sin\theta$$

ANNULAR-MIST FLOW

Liquid volume fraction (E_L) is determined using geometric considerations and a known liquid thickness, by the following equation:

$$E_L = 1 - \left(1 - 2\tilde{\delta}_L\right)^2 \frac{V_{SG}}{V_{SG} + FE\, V_{SL}}$$

The ΔP_{HH} is then calculated from the hydrostatic portion of the gas and liquid phase momentum balance equations.

Where:

$$\Delta P_{HH} = \rho_L \frac{g}{g_c} \sin\theta$$

$$\Delta P_{HH} = \rho_G \frac{g}{g_c} \sin\theta$$

BUBBLE FLOW

The bubble flow volumetric gas fraction is given by:

$$E_G = \frac{V_{SG}}{V_t}$$

Where V_t is the translational bubble velocity:

$$V_t = C_o V_m + V_b$$

With C_o assumed to be 1.2 and V_b given by the equation below:

$$V_b = 1.41 \left[\frac{g (\rho_L - \rho_G) \sigma}{\rho_L^2} \right]^{1/4} \sin\theta$$

The value of E_G is characterized by the range where:

$$0 \leq E_G \leq C_G = \frac{V_{SG}}{V_m}$$

Once the volumetric gas fraction (E_G) has been calculated, it is then used to calculate the mixture density (ρ_m). The mixture density can now be used to calculate the pressure change due to the hydrostatic head for the segment of pipe being investigated.

$$\Delta P_{HH} = \rho_m \frac{g}{g_c} \sin\theta$$

INTERMITTENT FLOW

Liquid volume fraction (E_L) is given by:

$$E_L = \frac{E_{Ls} V_t + V_{Gdb}(1 - E_{Ls}) - V_{SG}}{V_t}$$

Once the liquid holdup (E_L) has been calculated, it is then used to calculate the mixture density (ρ_m). The mixture density can now be used to calculate the pressure change due to the hydrostatic head for the segment of pipe being investigated.

$$\Delta P_{HH} = \rho_m \frac{g}{g_c} \sin\theta$$

Friction Pressure Loss

The frictional portion of the overall pressure gradient is determined based on pipe geometry and flow distribution. Each flow type has a separate calculation used to determine the pressure losses due to

friction. The details of these calculations are summarized here.

DISPERSED BUBBLE FLOW

The first step to determine the frictional pressure loss is to obtain a friction factor, f_m. The friction factor is obtained from standard methods using pipe roughness and Reynolds number, $Re_{\bar{m}}$:

$$Re_m = \frac{D\,\rho_m\,V_m}{\mu_m}$$

Where mixture density (ρ_m) and mixture viscosity (μ_m) are calculated from:

$$\rho_m = E_L \rho_L + E_G \rho_G$$

$$\mu_m = \mu_L E_L + \mu_G E_G$$

Finally, the expression for the pressure loss due to friction is:

$$\Delta P_f = \frac{2\,f_m\,V_m^2\,\rho_m}{g_c D}$$

STRATIFIED FLOW

The shear stresses for the stratified flow regime are determined using the following relationships:

$$\tau_{wG} = \frac{f_G \rho_G V_G^2}{2 g_c}$$

$$\tau_{wL} = \frac{f_L \rho_L V_L^2}{2 g_c}$$

$$\tau_i = \frac{f_i \rho_G V_i |V_i|}{2 g_c}$$

Where:

$$V_i = V_G - V_L$$

The friction factor at the gas/wall interface, f_G is determined using a single phased flow approach, the pipe roughness and the following Reynold's number:

$$Re_G = \frac{D_G \rho_G V_G}{\mu_G}$$

The friction factor for the liquid/wall interface, f_L, follows the empirical relationship:

$$f_L = 0.452 f_{SL}^{0.731}$$

The superficial velocity friction factor, f_{sL}, is obtained from standard methods using the pipe roughness and Reynolds number, Re_{sL}:

$$Re_{SL} = \frac{D \rho_L V_{SL}}{\mu_L}$$

The interfacial friction factor, f_i, is obtained from the empirical relationship:

$$f_i = \left(0.004 + 0.5 \times 10^{-6} Re_{SL}\right) Fr_L^{1.335} \left\{\frac{\rho_L D_g}{\rho_G V_G^2}\right\}$$

Where the Froude number, Fr_L, is defined as:

$$Fr_L = \frac{V_L}{\sqrt{g h_L}}$$

Finally, the expression for the pressure loss due to friction is determined from a portion of the momentum balance equations:

$$\Delta P_f = \frac{-\tau_{wL} S_L + \tau_i S_i}{A_L}$$

$$\Delta P_f = \frac{-\tau_{wG} S_G - \tau_i S_i}{A_G}$$

ANNULAR-MIST FLOW

The shear stresses for the annular-mist flow regime are determined using the following relationships:

$$\tau_{wL} = \frac{f_f \rho_L V_f^2}{2 g_c}$$

$$\tau_i = \frac{f_i \rho_c (V_c - V_f) |V_c - V_f|}{2 g_c}$$

The friction factor for the liquid film, f_f, is found using standard methods using the piper roughness and the film Reynolds number:

$$Re_f = \frac{D_f \rho_L V_f}{\mu_L}$$

The interfacial friction factor, f_i, and the liquid fraction entrained, FE, also need to be determined. These are defined by empirical relationships.

$$\frac{FE}{1-FE} = 0.735\, N_B^{0.074} \left(\frac{V_{SG}}{V_{SL}}\right)^{0.2}$$

$$\frac{f_i}{f_c} = 0.24 \left\{\frac{\sigma}{\rho_c V_c^2 D_c}\right\}^{0.085} Re_f^{0.305}$$

Where N_B (a dimensionless number) is defined as:

$$N_B = \frac{\mu_L^2 V_{SG}^2 \rho_G}{\sigma^2 \rho_L}$$

Finally, the expression for the pressure loss due to friction is determined from a portion of the momentum balance equations:

$$\Delta P_f = \frac{-\tau_{wL} S_L + \tau_i S_i}{A_f}$$

$$\Delta P_f = \frac{-\tau_i S_i}{A_c}$$

BUBBLE FLOW

The friction factor for bubble flow, f_{mL}, is obtained from standard methods using pipe roughness and the following definition of Reynolds number:

$$Re_{mL} = \frac{D \rho_L V_m}{\mu_L}$$

Now, the expression for the pressure loss due to friction is:

$$\Delta P_f = \frac{2 f_{mL} V_m^2 \rho_m}{g_c D}$$

INTERMITTENT FLOW

The frictional pressure loss for intermittent flow is taken from the momentum balance written for a slug-bubble unit:

$$\Delta P_f = \frac{1}{L_u}\left[L_s\left(\frac{\tau_{Ls} \pi D}{A}\right) + L_f\left(\frac{\tau_{Lf} S_{Lf} + \tau_{Gdb} S_{Gdb}}{A}\right)\right]$$

There is no reliable method to determine the slug length, L_s, the length of the bubble region, L_f, of the frictional pressure loss in the gas bubble. Therefore, the following simplified approach is adopted given the stated uncertainties.

$$\Delta P_f = \eta \left(\frac{dp}{dL}\right)_{fr_{SL}} + (1-\eta)\left(\frac{dP}{dL}\right)_{fr_{AM}}$$

Where η is a weighting factor determined empirically relation the slug length to the total slug unit length (L_s/L_u):

$$\eta = C_L^{(0.75-E_L)}$$

Where $\eta \leq 1.0$

$\left(\frac{dp}{dL}\right)_{fr_{SL}}$

Now the frictional pressure gradient for the slug portion, , is obtained from:

$$\left(\frac{dp}{dL}\right)_{fr_{SL}} = 2\,\frac{f_{mL} V_m^2 \rho_m}{gD}$$

The friction factor, f_{mL}, is calculated from standard methods using piper roughness and the following Reynolds number:

$$Re_{mL} = \frac{D\,\rho_L\,V_m}{\mu_L}$$

The annular-mist frictional pressure gradient is calculated from:

$$\left(\frac{dp}{dL}\right)_{fr_{AM}} = \frac{4\,\tau_{wL}}{D}$$

Where the shear stress, τ_{wL}, is determined from:

$$\tau_{wL} = \frac{f_f\,\rho_L\,V_f^2}{2g_c}$$

When the calculated film height is less than $1x10^{-4}$, the frictional pressure gradient for the annular-mist flow portion, $\left(\frac{dp}{dL}\right)_{fr_{AM}}$, is obtained from:

$$\left(\frac{dp}{dL}\right)_{fr_{AM}} = \frac{2 f_m V_m^2 \rho_m}{g_c D}$$

Where the friction factor, f_m, is obtained from standard methods using the pipe roughness and the following Reynolds number:

$$Re_m = \frac{D \rho_m V_m}{\mu_m}$$

Note: For the Petalas and Aziz correlation in Piper, convergence issues have been observed for heavily **looped systems** with very **low gas rates** and extremely **high liquid rates**.

Nomenclature

D = inside pipe diameter (ft)
E_L= in-situ liquid volume fraction (liquid holdup)
f_{tp}= two-phase friction factor
A = Cross-sectional area
C_0= Velocity distribution coefficient
D = Pipe internal diameter
E = In situ volume fraction
FE = Liquid fraction entrained
g = Acceleration due to gravity
h_L= Height of liquid (stratified flow)
L = Length
p = Pressure
Re = Reynolds number
S = Contact perimeter
V_{SG}= Superficial gas velocity
V_{SL}= Superficial liquid velocity
δ_L= Liquid film thickness (annular-mist)
ε = Pipe roughness
η = Pressure gradient weighting factor (intermittent flow)
θ = Angle of inclination
μ = Viscosity
ρ = Density

σ = Interfacial (surface) tension
τ = Shear stress
$\tilde{x}$ = Dimensionless quantity, x
Subscripts
b = relating to the gas bubble
c = relating to the gas core
f = relating to the liquid film
db = relating to the dispersed bubbles
G = relating to the gas phase
i = relating to the gas/liquid interface
L = relating to the liquid phase
m = relating to the mixture
SG = based on superficial gas velocity
s = relating to the liquid slug
SL = based on superficial liquid velocity
wL = relating to the wall-liquid interface
wG = relating to the wall-gas interface

References

Petalas, N., and Aziz, K., “A Mechanistic Model for Multiphase Flow in Pipes”, JCPT, 43-55, June 2000. Source: JCPT.

Gray Correlation

The Gray correlation was developed by H.E. Gray (Gray, 1978), specifically for wet gas wells. Although this correlation was developed for vertical flow, we have implemented it in both vertical and inclined pipe pressure drop calculations. To correct the 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 the mixture density, which is in turn 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.

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:

$$N_1 = \frac{\rho_{NS}^2 V_m^4}{g\sigma(\rho_L - \rho_G)}$$

$$N_2 = \frac{gD^2(\rho_L - \rho_G)}{\sigma}$$

$$N_3 = 0.0814\left[1 - 0.0554 \ln\left\{1 + \frac{730 R_v}{R_v + 1}\right\}\right]$$

where:

$$R_v = \frac{V_{sl}}{V_{sg}}$$

They are then combined as follows:

$$E_L = 1 - (1 - C_L) \times (1 - \exp(f_1))$$

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 calculate the mixture density (ρ_m). The mixture density is, in turn, used to calculate the pressure change due to the hydrostatic head of the vertical component of the pipe or well.

$$\Delta P_{HH} = \frac{\rho_m g \Delta z}{144 g_c}$$

Note: For the equations found in the Gray correlation, σ is given in lb_{mass} / s^2. We have implemented them using σ with units of dynes / cm and have converted the equations by multiplying σ by 0.00220462. (1 dyne / cm = 0.00220462 lb_f / s^2)

Friction Pressure Loss

The Gray Correlation assumes that the effective 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

$$k_e = k^\circ$$

if

$$R_v < 0.007$$ then

$$k_e = k + R_v \left\{ \frac{k^\circ - k}{0.007} \right\}$$

where:

$$k^\circ = \frac{28.5\sigma}{\rho_{NS} V_m^2}$$

$$R_v = \frac{V_{sl}}{V_{sg}}$$

The 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 assuming a Reynolds Number (Re) of 10^7. Finally, the expression for the friction pressure loss is:

$$\Delta P_f = \frac{2 f_{tp} V_m^2 \rho_{NS} L}{144 g_c D}$$

Note: The original publication contained a misprint (0.0007 instead of 0.007). Also, the surface tension (σ) is given in units of lb_f/s^2. We used a conversion factor of 0.00220462 dynes/cm = 1 lb_f/s^2.

Nomenclature

D = inside pipe diameter (ft)
E_L = in-situ liquid volume fraction (liquid holdup)
f_{tp} = two-phase friction factor
g = gravitational acceleration (32.2 ft/ s^2)
g_c = conversion factor (32.2 (lb_m ft)/($lb_f s^2$))
k = absolute roughness of the pipe (in)
k_e = effective roughness (in)
L = length of pipe (ft)
ΔP_{HH} = pressure change due to hydrostatic head (psi)
ΔP_f = pressure change due to friction (psi)
V_{sl} = superficial liquid velocity (ft/s)
V_{sg} = superficial gas velocity (ft/s)
V_m = mixture velocity (ft/s)
Δz = elevation change (ft)
ρ_G = gas density (lb/ft^3)
ρ_L = liquid density (lb/ft^3)
ρ_{NS} = no-slip density (lb/ft^3)
ρ_m = mixture density (lb/ft^3)
σ = gas / liquid surface tension (lb_f/s^2)

Hagedorn and Brown Correlation

Experimental data obtained from a 1500ft deep, instrumented vertical well was used in the development of the Hagedorn and Brown correlation. Pressures were measured for flow in tubing sizes that ranged from 1 " to 1 ½" OD. A wide range of liquid rates and gas/liquid ratios were used. As with the Gray correlation, our software will calculate 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 the 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, then the Griffith correlation is used to calculate the in-situ volume fraction. In this case the Griffith correlation is also used to calculate the 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.

Hydrostatic Pressure Difference

The Hagedorn and Brown correlation uses four dimensionless parameters to correlate liquid holdup. These four parameters are:

$$N_{lv} = 1.938 \cdot V_{sl}\left(\frac{\rho_L}{\sigma}\right)^{1/4}$$

$$N_{gv} = 1.938 \cdot V_{sg}\left(\frac{\rho_L}{\sigma}\right)^{1/4}$$

$$N_d = 120.872 \cdot D\left(\frac{\rho_L}{\sigma}\right)^{1/2}$$

$$N_L = 0.15726\mu_L\left(\frac{1}{\rho_L\sigma^3}\right)^{1/4}$$

Various combinations of these parameters are then plotted against each other to determine the liquid holdup.

For the purposes of programming, these curves were converted into equations. The first curve provides a value for . This value is then used to calculate a dimensionless group, $\bar{X}_h$. can then be obtained from a plot of vs. $\bar{X}_h$. Finally, the third curve is a plot of vs. another dimensionless group of numbers, $\bar{X}_\psi$. Therefore, the in-situ liquid volume fraction, which is denoted by , is calculated by:

$$E_L = \frac{E_L}{\psi} \times \psi$$

The hydrostatic head is once again calculated by the standard equation:

$$\Delta P_{HH} = \frac{\rho_m g \Delta z}{144 g_c}$$

where:

$$\rho_m = \rho_L E_L + \rho_G (1 - E_L)$$

Friction Pressure Loss

The friction factor is calculated using the Chen equation and a Reynolds number equal to:

$$\mathrm{Re} = \frac{\rho_{NS} V_m D}{\mu_m}$$

Note: In the Hagedorn and Brown correlation the 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:

$$\Delta P_f = \frac{2 f \rho_f V_m^2 L}{144 g_c D}$$

where:

$$\rho_f = \frac{\rho_{NS}^2}{\rho_m}$$

Modifications

We have implemented two modifications to the original Hagedorn and Brown Correlation. The first modification is simply the replacement of 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.

If $E_L < C_L$, then $E_L = C_L$.

The second modification involves the 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.

The Griffith Correlation (Modification to the Hagedorn and Brown Correlation)

In the Griffith correlation the liquid holdup is given by:

$$E_L = 1 - \frac{1}{2}\left[1 + \frac{V_m}{V_s} - \sqrt{\left(1 + \frac{V_m}{V_s}\right)^2 - 4\left(\frac{V_{sg}}{V_s}\right)}\right]$$

where:

$$V_s = 0.8\, ft/s$$

The 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:

$$\mathrm{Re} = \frac{\rho_L V_L D}{\mu_L}$$

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 not single phase liquid properties. The Reynolds number is then used to calculate the friction factor using the Chen equation. Finally, the friction pressure loss is calculated as follows:

$$\Delta P_f = \frac{2 f \rho_L V_L^2 L}{144 g_c D}$$

The liquid density and the in-situ liquid velocity are used to calculate the pressure drop due to friction.

Nomenclature

C_L = input liquid volume fraction
C_G = input gas volume fraction
D = inside pipe diameter (ft)
E_L = in-situ liquid volume fraction (liquid holdup)
f = Fanning friction factor
g = gravitational acceleration (32.2 ft/ s^2)
g_c = conversion factor (32.2 (lb_m ft) / ($lb_f s^2$))
L = length of calculation segment (ft)
ΔP_{HH} = pressure change due to hydrostatic head (psi)
ΔP_f = pressure change due to friction (psi)
V_{sl} = superficial liquid velocity (ft/s)
V_{sg} = superficial gas velocity (ft/s)
V_m = mixture velocity (ft/s)
V_L = in-situ liquid velocity (ft/s)
Δz = elevation change (ft)
μ_L = liquid viscosity (cp)
μ_m = mixture viscosity (cp)
μ_G = gas viscosity (cp)
ρ_G = gas density (lb/ft^3)
ρ_L = liquid density (lb/ft^3)
ρ_{NS} = no-slip density (lb/ft^3)
ρ_m = mixture density (lb/ft^3)
$\rho_f = (\rho_{NS}^2 / \rho_m)$ (lb/ft^3)
σ = gas / liquid surface tension (dynes/cm)

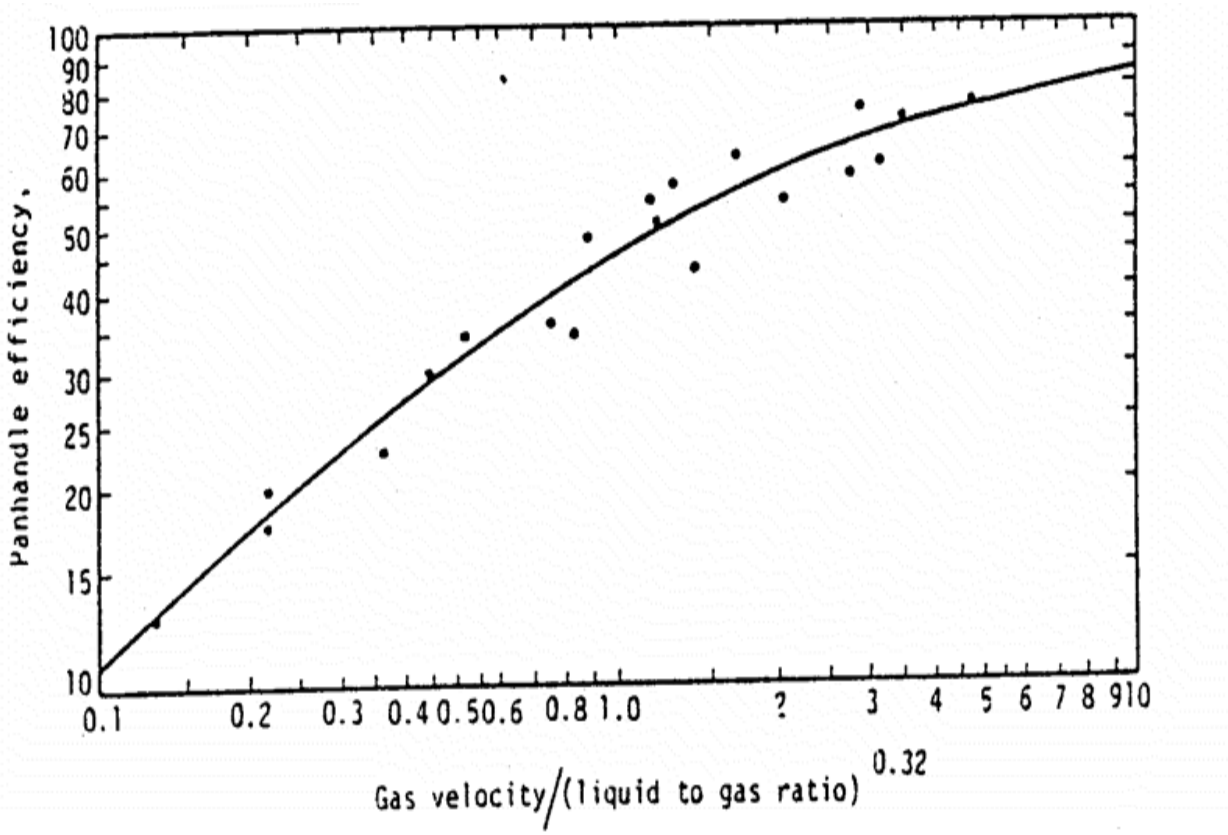
Flanigan Correlation

The Flanigan correlation is an extension of the Panhandle single-phase correlation to multiphase flow. It was developed to account for the additional pressure loss caused by the presence of liquids. The correlation is empirical and is based on studies of small amounts of condensate in gas lines. To account for liquids, Flanigan developed a relationship for the Flow Efficiency term of the Panhandle equation as a function of superficial gas velocity and liquid to gas ratio. Flanigan also developed a liquid holdup factor to account for the hydrostatic pressure difference in upward inclined flow.

In Piper, the Flanigan correlation has been applied to the Panhandle and Modified Panhandle correlations such that Flanigan is derived from Panhandle and the Modified Flanigan derives from Modified Panhandle.

Friction Pressure Loss

In the Flanigan correlation, the friction pressure drop calculation accounts for liquids by adjusting the Panhandle efficiency (E) according to the following plot.



Note: When gas velocities are high or liquid-gas ratios are very low, the Panhandle efficiency approaches 85%.

Hydrostatic Pressure Difference

When calculating the pressure losses due to hydrostatic effects the Flanigan correlation ignores downhill flow. The hydrostatic head caused by the liquid content is calculated as follows:

$$\Delta P_{HH} = \rho_L \frac{g}{144 g_c} E_L \sum h_i$$

Where:

ρ_L = liquid density (lb/ft^3)
h_i = the vertical "rises" of the individual sections of the pipeline (ft)
E_L = Flanigan holdup factor (in-situ liquid volume fraction)

The Flanigan holdup factor is calculated using the following equation.

$$E_L = \frac{1}{1 + 0.3264 V_{sg}^{1.006}}$$

Application of the Flanigan hydrostatic pressure calculation (including gas hydrostatic) has been implemented for each pipe segment in the following form:

$$\Delta P_{HH} = \left[\rho_g (1 - E_L) + \rho_L E_L\right] \frac{g}{144 g_c} h$$

and EL is defined as per Flanigan's original work.

Nomenclature

E = Panhandle efficiency
E_L = Flanigan holdup factor (in-situ liquid volume fraction)
g = gravitational acceleration (32.2 ft/ s^2)
g_c = conversion factor (32.2 (lb_m ft) / ($lb_f s^2$))
h = vertical rise of the pipeline segment
h_i = the vertical "rises" of the individual sections of the pipeline (ft)
ΔP_{HH} = pressure change due to hydrostatic head (psi)
ΔP_f = pressure change due to friction (psi)
V_{sg} = superficial gas velocity (ft/s)
ρ_L = liquid density (lb/ft^3)

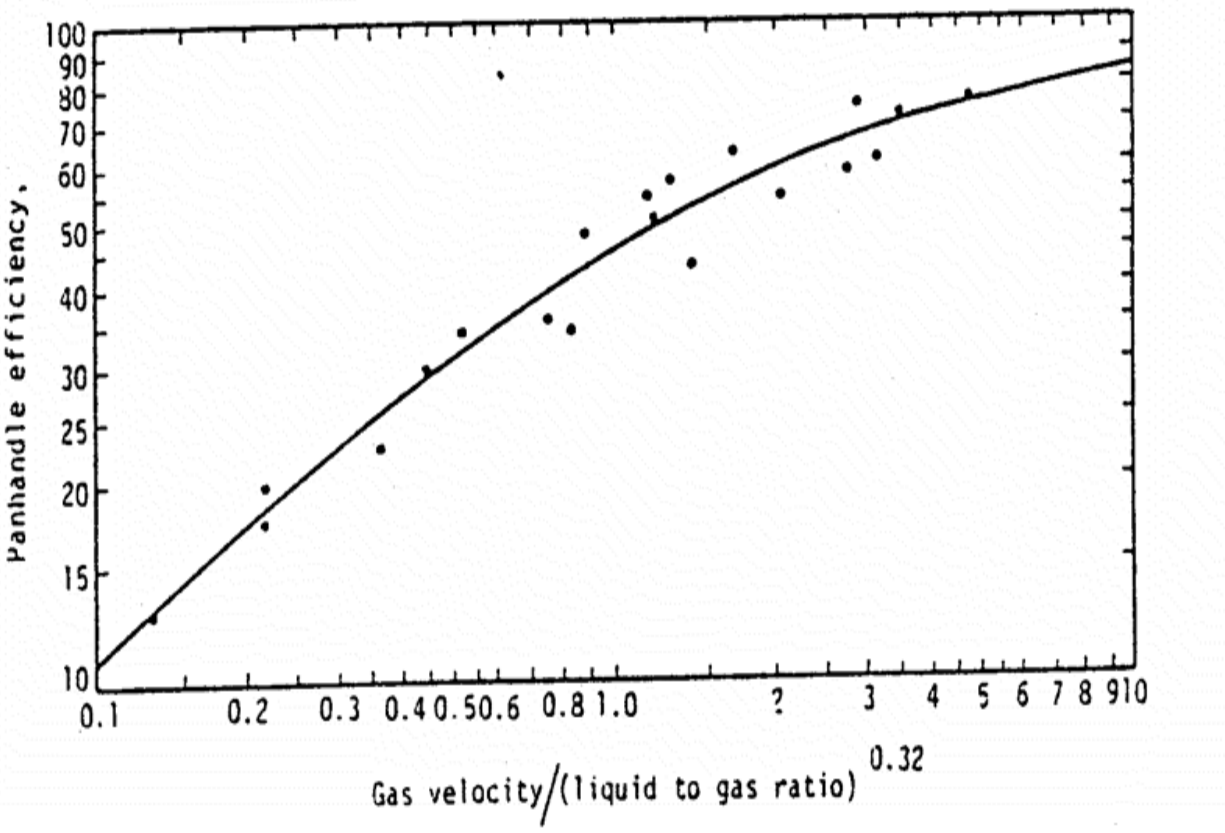
Modified-Flanigan Correlation

The Modified Flanigan correlation is an extension to the Modified Panhandle single-phase correlation. The Flanigan correlation was developed as a method to account for the additional pressure loss caused by the presence of liquids. The correlation is empirical and is based on studies of small amounts of condensate in gas lines. To account for liquids, Flanigan developed a relationship for the Flow Efficiency term of the Panhandle equation as a function of superficial gas velocity and liquid to gas ratio. Flanigan also developed a liquid holdup factor to account for the hydrostatic pressure difference in upward inclined flow.

In Piper, the Flanigan correlation has been applied to the Panhandle and Modified Panhandle correlations such that Flanigan is derived from Panhandle and the Modified Flanigan derives from Modified Panhandle.

Friction Pressure Loss

In the Flanigan correlation, the friction pressure drop calculation accounts for liquids by adjusting the Panhandle efficiency (E) according to the following plot.



Note: When gas velocities are high or liquid-gas ratios are very low, the Panhandle efficiency approaches 85%.

Hydrostatic Pressure Difference

When calculating the pressure losses due to hydrostatic effects the Flanigan correlation ignores downhill flow. The hydrostatic head caused by the liquid content is calculated as follows:

$$\Delta P_{HH} = \rho_L \frac{g}{144 g_c} E_L \sum h_i$$

Where:

ρ_L = liquid density (lb/ft^3)
h_i = the vertical "rises" of the individual sections of the pipeline (ft)
E_L = Flanigan holdup factor (in-situ liquid volume fraction)

The Flanigan holdup factor is calculated using the following equation:

$$E_L = \frac{1}{1 + 0.3264 V_{sg}^{1.006}}$$

Application of the Flanigan hydrostatic pressure calculation (including gas hydrostatic) has been implemented for each pipe segment in the following form:

$$\Delta P_{HH} = \left[\rho_g (1 - E_L) + \rho_L E_L\right] \frac{g}{144 g_c} h$$

A and E_L are defined as per Flanigan's original work.

Nomenclature

E = Panhandle efficiency
E_L = Flanigan holdup factor (in-situ liquid volume fraction)
g = gravitational acceleration (32.2 ft/ s^2)
g_c = conversion factor (32.2 (lb_m ft) / ($lb_f s^2$))
h = vertical rise of the pipeline segment
h_i = the vertical "rises" of the individual sections of the pipeline (ft)
ΔP_{HH} = pressure change due to hydrostatic head (psi)
ΔP_f = pressure change due to friction (psi)
V_{sg} = superficial gas velocity (ft/s)
ρ_L = liquid density (lb/ft^3)

Weymouth Correlation

This correlation is similar in its form to the Panhandle and the Modified Panhandle correlations. It was designed for single-phase gas flow in pipelines. As such, it calculates only the pressure drop due to friction. However, we have applied the standard equation for calculating hydrostatic head to the vertical component of the pipe, and thus our Weymouth correlation accounts for HORIZONTAL, INCLINED and VERTICAL pipes. The Weymouth equation can only be used for single-phase gas flow.

Friction Pressure Loss

The pressure drop due to friction is given by:

$$P_1^2 - P_2^2 = T_a L z_a \kappa \frac{G}{D^{5.334}} \left[\frac{Q_G^o}{E}\right]^2 \left[\frac{P^o}{T^o}\right]^2$$

Where: **$\kappa = 5.3213 \times 10^{-6}$**

The Weymouth equation incorporates a simplified representation of the friction factor, which is built into the equation. To account for real life situations, the flow efficiency factor, E, was included in the equation. The flow efficiency generally used is 115%. Our software defaults to this value as well (Mattar and Zaoral, 1984).

Hydrostatic Pressure Loss

The original Weymouth equation only accounted for ΔP_f. However, by applying the hydrostatic head calculations, the Weymouth equation has been adapted for vertical and inclined pipes. The hydrostatic head is calculated by:

$$\Delta P_{HH} = \frac{\rho_G g \Delta z}{144 g_c}$$

Nomenclature

D = pipe inside diameter (in)
E = Panhandle/Weymouth efficiency factor
G = gas gravity
g = gravitational acceleration (32.2 ft/ s^2)
g_c = conversion factor (32.2 (lb_m ft) / ($lb_f s^2$))
L = length (mile)
P° = reference pressure for standard conditions
P_1 = upstream pressure
P_2 = downstream pressure
ΔP_{HH} = pressure change due to hydrostatic head (psi)
Q_G° = gas flow rate at standard conditions, T°, P°, (ft^3/d)
T° = reference temperature for standard conditions (°R)
T_a = average temperature (°R)
z_a = average compressibility factor
Δz = elevation change (ft)
ρ_G = gas density (lb/ft^3)

Panhandle Correlations

The original Panhandle correlation (Gas Processors Suppliers Association, 1980) was developed for single-phase gas flow in horizontal pipes. As such, only the pressure drop due to friction was taken into account by the Panhandle equation. However, we have applied the standard equation for calculating hydrostatic head to the vertical component of the pipe, and thus our Panhandle correlation accounts for horizontal, inclined and vertical pipes. The Panhandle correlation can only be used for single-phase gas flow.

Friction Pressure Loss

The Panhandle correlation can be written as follows:

$$P_1^2 - P_2^2 = T_a L z_a \kappa \frac{G^{0.8539}}{D^{4.8539}} \left[\frac{Q_G^\circ}{E}\right]^{1.8539} \left[\frac{P^\circ}{T^\circ}\right]^2$$

Where: **$\kappa = 1.279 \times 10^{-5}$**

The Panhandle equation incorporates a simplified representation of the friction factor, which is built into the equation. To account for real life situations, the flow efficiency factor, E, was included in the

equation. This flow efficiency generally ranges from 0.8 to 0.95. Although we recognize that a common default for the flow efficiency is 0.92, our software defaults to E = 0.85, as our experience has shown this to be more appropriate (Mattar and Zaoral, 1984).

Hydrostatic Pressure Difference

The original Panhandle equation only accounted for . However, by applying the hydrostatic head calculations the Panhandle correlation has been adapted for vertical and inclined pipes. The hydrostatic head is calculated by:

$$\Delta P_{HH} = \frac{\rho_G g \Delta z}{144 g_c}$$

Nomenclature

D = pipe inside diameter (in)
E = Panhandle/Weymouth efficiency factor
G = gas gravity
g = gravitational acceleration (32.2 ft/ s^2)
g_c = conversion factor (32.2 (lb_m ft) / ($lb_f s^2$))
L = length (mile)
P° = reference pressure for standard conditions
P_1 = upstream pressure
P_2 = downstream pressure
ΔP_{HH} = pressure change due to hydrostatic head (psi)
Q_G° = gas flow rate at standard conditions, T°, P°, (ft^3/d)
T° = reference temperature for standard conditions (°R)
T_a = average temperature (°R)
z_a = average compressibility factor
Δz = elevation change (ft)
ρ_G = gas density (lb/ft^3)

Modified Panhandle Correlation

The Modified Panhandle correlation (Gregory, et al, 1980) is a modified version of the original Panhandle equation (Gas Processors Suppliers Association, 1980) and is sometimes referred to as the Panhandle Eastern Correlation or the Panhandle B correlation. As such, the Modified Panhandle is also a single-phase correlation for horizontal flow. As with the original Panhandle equation, we have

applied the standard hydrostatic head equation to the vertical component of the pipe, and thus, our Modified Panhandle correlation accounts for horizontal, inclined and vertical flow. The Modified Panhandle correlation can only be used for single-phase gas flow.

Friction Pressure Loss

The pressure drop due to friction is given by:

$$P_1^2 - P_2^2 = T_a L z_a \kappa \frac{G^{0.9608}}{D^{4.9608}} \left[\frac{Q_G^\circ}{E} \right]^{1.9608} \left[\frac{P^\circ}{T^\circ} \right]^2$$

Where: $\kappa = 2.385 \times 10^{-6}$

Similarly to the original Panhandle equation, the Modified Panhandle equation used a simplified representation of the friction factor, which was built into the equation. To account for real life situations, a flow efficiency, E, was included in the equation. Although this efficiency factor is generally thought to range from 0.88 to 0.94, our software defaults to E = 0.80, as this is considered to be more appropriate. (Mattar and Zaoral, 1984).

Hydrostatic Pressure Difference

We have accounted for the vertical component of flow in pipes by using the standard equation for hydrostatic head.

$$\Delta P_{HH} = \frac{\rho_G g \Delta z}{144 g_c}$$

Nomenclature

D = pipe inside diameter (in)
E = Panhandle/Weymouth efficiency factor
G = gas gravity
g = gravitational acceleration (32.2 ft/ s^2)
g_c = conversion factor (32.2 (lb_m ft) / ($lb_f s^2$))
L = length (mile)
P° = reference pressure for standard conditions
P_1 = upstream pressure
P_2 = downstream pressure
ΔP_{HH} = pressure change due to hydrostatic head (psi)
Q_G° = gas flow rate at standard conditions, T°, P°, (ft^3/d)
T° = reference temperature for standard conditions (°R)
T_a = average temperature (°R)
z_a = average compressibility factor
Δz = elevation change (ft)
ρ_G = gas density (lb/ft^3)

Fanning Gas Correlation (Multi-step Cullender and Smith)

The Fanning friction factor pressure loss (ΔP_f) can be combined with the hydrostatic pressure difference (ΔP_{HH}) to give the total pressure loss. The Fanning Gas Correlation is the name used in this document to refer to the calculation of the hydrostatic pressure difference (ΔP_{HH}) and the friction pressure loss (ΔP_f) for single-phase gas flow, using the following standard equations.

This formulation for pressure drop is applicable to pipes of all inclinations. When applied to a vertical wellbore it is equivalent to the Cullender and Smith method. However, it is implemented as a multi-segment procedure instead of a 2 segment calculation.

Friction Pressure Loss

The Fanning equation is widely thought to be the most generally applicable single phase equation for calculating friction pressure loss. It utilizes friction factor charts (Knudsen and Katz, 1958), which are functions of Reynold's number and relative pipe roughness. These charts are also often referred to as the Moody charts. We use the equation form of the Fanning friction factor as published by Chen, 1979.

$$\frac{1}{\sqrt{f}} = -4.0 log\left[0.2698\left(k/D\right) - \frac{5.0452}{Re} log\left\{0.3539\left(k/D\right)^{1.1098} + \frac{5.8506}{Re^{0.8981}}\right\}\right]$$

The method for calculating the Fanning Friction factor is the same for single-phase gas or single-phase liquid.

Hydrostatic Pressure Difference

The calculation of hydrostatic head is different for a gas than for a liquid, because gas is compressible and its density varies with pressure and temperature, whereas for a liquid a constant density can be safely assumed. Either way the hydrostatic pressure difference is given by:

$$\Delta P_{HH} = \frac{g}{144 g_c} \rho_G \Delta z$$

Since varies with pressure, the calculation must be done sequentially in small steps to allow the density to vary with pressure.

Nomenclature

D = pipe inside diameter (in)
f = Fanning friction factor
g = gravitational acceleration (32.2 ft/ s^2)
g_c = conversion factor (32.2 (lb_m ft) / ($lb_f s^2$))
k/D = relative roughness (unitless)
L = length (ft)
ΔP_{HH} = pressure change due to hydrostatic head (psi)
ΔP_f = pressure change due to friction (psi)
Re = Reynold's number
V = velocity (ft/s)
Δz = elevation change (ft)
ρ_G = gas density (lb/ft^3)

Flow Efficiency

Flow efficiency is a tuning parameter used to match calculated pressures to measured pressures. These two pressures often differ as most calculations involve unknowns, approximations, assumptions, or measurement errors. When measured pressures are available for comparison with calculated values, the Flow Efficiency can be used to obtain a match between the two.

Flow Efficiency applies to the Panhandle family of correlations (Panhandle, Modified Panhandle, and Weymouth). Recommended initial values for flow effciency are Panhandle (85%), Modified Panhandle (80%) and Weymouth (115%). These values were derived from "Gas Pipeline Efficiencies and Pressure Gradient Curves". This technical paper can be found on Fekete's website. If measured pressures are not available for comparison, then the default value should be used.

Flow Efficiency adjusts the correlation such that decreasing the flow efficiency increases the pressure loss. Efficiencies greater than 100% are possible. Low efficiencies could be a result of roughness caused by factors such as corrosion, scale, sulfur or calcium deposition and restrictions. Restrictions in a wellbore may be caused by downhole equipment, profiles, etc. Low efficiencies could also be the result of liquid loading. Flow efficiencies less than 30% or greater than 150% should be treated with caution.

UNITS: %

DEFAULT:

Panhandle (Original Piper) = 100%

Panhandle = 85%

Modified Panhandle = 80%

Weymouth = 115%

Roughness (k)

This is defined as the distance from the peaks to the valleys in pipe wall irregularities. Roughness is used in the calculation of pressure drop due to friction. For clean, new pipe the roughness is determined by the method of manufacture and is usually between 0.00055 to 0.0019 inches (Cullender and Binckley, 1950, Smith et al. 1954, Smith et al. 1956). For new pipe or tubing used in gas wells the roughness has been found to be in the order of 0.00060 or 0.00065 inches. Roughness must be between 0 and 0.01 inches.

Roughness can be used to tune the correlations to measured conditions in a similar way to the Flow Efficiency. Changes in roughness only affect the friction component of the calculations while the Flow Efficiency is applied to the friction and hydrostatic components of pressure loss. Roughness does not affect the calculations for static conditions. In this case, a match between measured and calculated pressures may be obtained by adjusting the fluid gravity or temperatures, as appropriate.

UNITS: Inches (mm)

DEFAULT: 0.0006 inches

Gas Rate

Typically this refers to the amount of gas flowing through a pipe. It is usually measured in units of volume per unit time.

UNITS: MMscfd ($10^3m^3/d$)

DEFAULT: None

Liquid Rate

This refers to the amount of liquid flowing through a pipe. It is usually measured in units of volume per unit time.

UNITS: bbl/d (m^3/d)

DEFAULT: 0

Inlet Gas Rate

This refers to the amount of gas flowing into a node/unit/link. It is usually measured in units of volume per unit time.

UNITS: MMscfd ($10^3m^3/d$)

DEFAULT: None

Outlet Gas Rate

Typically this refers to the amount of gas exiting a node/unit/link. It is usually measured in units of volume per unit time.

UNITS: MMscfd ($10^3m^3/d$)

DEFAULT: None

Gas Velocity

Typically this refers to the speed of the gas flowing through a pipe. It is usually measured in units of distance per unit time.

UNITS: ft/s (m/s)

DEFAULT: None

Erosional Velocity Rate

When fluid flows through a pipe at high velocities, erosion of the pipe can occur. Erosion can occur when the fluid velocity through a pipe is greater than the calculated erosional velocity. The calculation for the erosional velocity is performed using a constant that ranges from 75 to 150. A good value for the constant has been found to be 100, although this can be changed through the Defaults in the Options menu.

UNITS: ft/s (m/s)

DEFAULT: None

Phase Volume Correlations

With Piper, you can calculate in-situ phases as a function of temperature and pressure by way of either the Wilson equilibrium ratio method or the Peng Robinson equation of state.

Equilibrium Ratios

Piper includes the Wilson equilibrium ratio calculation. This is the most basic equilibrium ratio method and is also used as a first iteration approximation of equilibrium ratios for the Peng-Robinson equation of state.

The Wilson equilibrium ratio correlation is as follows:

$$K_i = \frac{p_{ci}}{p} e^{\left[5.37(1+\omega_i)\left(1-\frac{T_{ci}}{T}\right)\right]}$$

Where K_i is calculated for each component and where $\omega_i, p_{ci}, and\ T_{ci}$ are all stored parameters for each component.

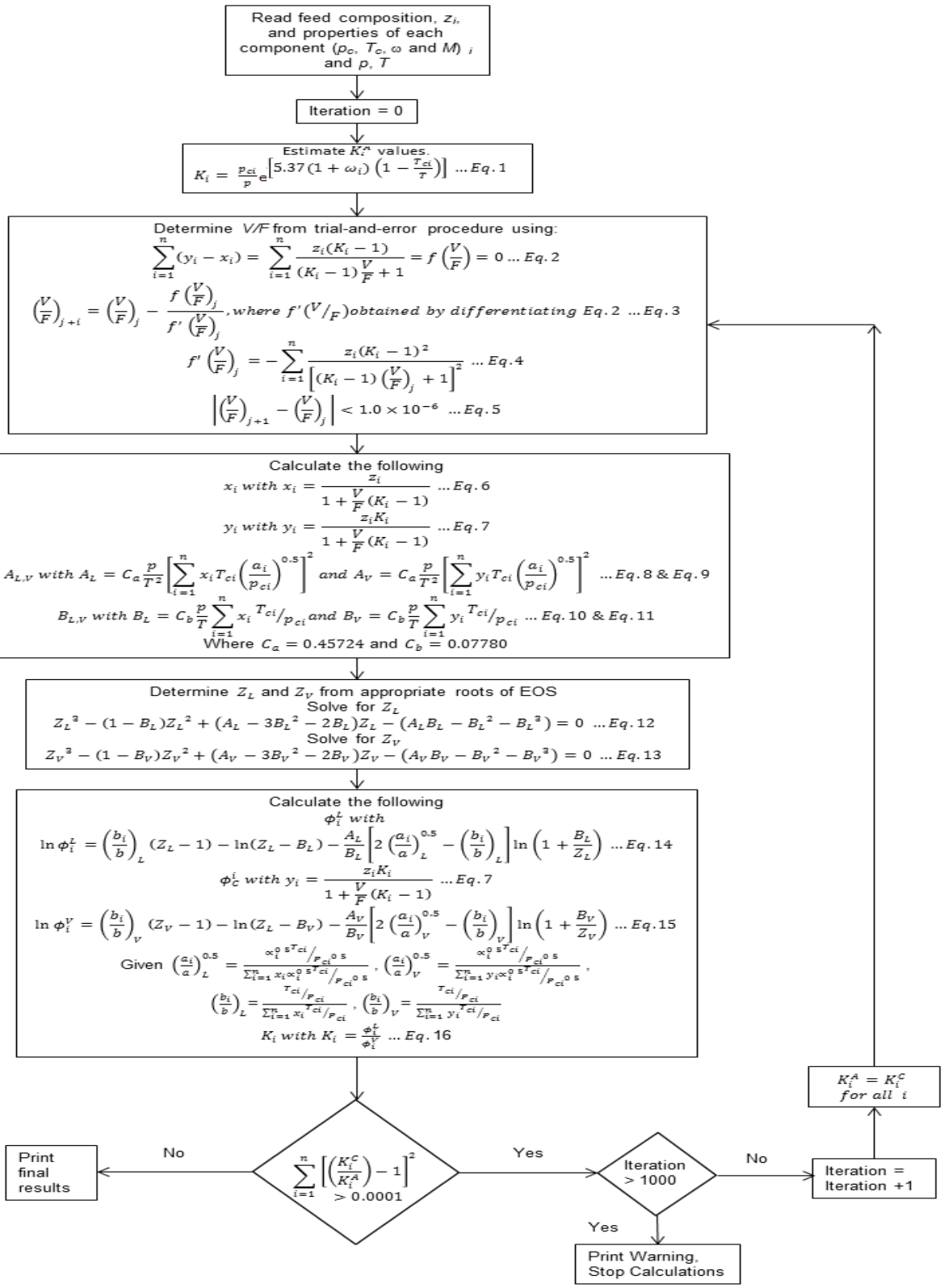
Peng-Robinson Equation of State

Piper uses the Peng Robinson equation of state to solve for phase volumes in the pipeline. Piper requires a 12 component compositional definition to use Peng Robinson.

Piper currently does not perform volume translation on its Peng-Robinson solution.

Water is also currently considered outside of the equation of state model.

The following iterative process is used to calculate equilibrium ratios and from that the molar volumes of the gas and oil phases. Note that Wilson equilibrium ratios are calculated as the first guesses of the equilibrium ratios.


Read feed composition, z_i, and properties of each component (p_c, T_c, ω and M) $_i$ and p, T
Iteration = 0
Estimate K_i^A values.
$K_i = \frac{p_{ci}}{p} e^{\left[5.37(1+\omega_i)\left(1-\frac{T_{ci}}{T}\right)\right]}$ ...Eq.1
Determine V/F from trial-and-error procedure using:
$\sum_{i=1}^{n}(y_i - x_i) = \sum_{i=1}^{n}\frac{z_i(K_i-1)}{(K_i-1)\frac{V}{F}+1} = f\left(\frac{V}{F}\right) = 0$ ...Eq.2
$\left(\frac{V}{F}\right)_{j+i} = \left(\frac{V}{F}\right)_j - \frac{f\left(\frac{V}{F}\right)_j}{f'\left(\frac{V}{F}\right)_j}$, where $f'(V/F)$ obtained by differentiating Eq.2 ...Eq.3
$f'\left(\frac{V}{F}\right)_j = -\sum_{i=1}^{n}\frac{z_i(K_i-1)^2}{\left[(K_i-1)\left(\frac{V}{F}\right)_j+1\right]^2}$ ...Eq.4
$\left|\left(\frac{V}{F}\right)_{j+1} - \left(\frac{V}{F}\right)_j\right| < 1.0\times10^{-6}$ ...Eq.5
Calculate the following
x_i with $x_i = \frac{z_i}{1+\frac{V}{F}(K_i-1)}$ ...Eq.6
y_i with $y_i = \frac{z_iK_i}{1+\frac{V}{F}(K_i-1)}$ ...Eq.7
$A_{L,V}$ with $A_L = C_a\frac{p}{T^2}\left[\sum_{i=1}^{n}x_iT_{ci}\left(\frac{a_i}{p_{ci}}\right)^{0.5}\right]^2$ and $A_V = C_a\frac{p}{T^2}\left[\sum_{i=1}^{n}y_iT_{ci}\left(\frac{a_i}{p_{ci}}\right)^{0.5}\right]^2$ ...Eq.8 & Eq.9
$B_{L,V}$ with $B_L = C_b\frac{p}{T}\sum_{i=1}^{n}x_i\,{}^{T_{ci}}/_{p_{ci}}$ and $B_V = C_b\frac{p}{T}\sum_{i=1}^{n}y_i\,{}^{T_{ci}}/_{p_{ci}}$ ...Eq.10 & Eq.11
Where $C_a = 0.45724$ and $C_b = 0.07780$
Determine Z_L and Z_V from appropriate roots of EOS
Solve for Z_L
$Z_L^3 - (1-B_L)Z_L^2 + (A_L - 3B_L^2 - 2B_L)Z_L - (A_LB_L - B_L^2 - B_L^3) = 0$ ...Eq.12
Solve for Z_V
$Z_V^3 - (1-B_V)Z_V^2 + (A_V - 3B_V^2 - 2B_V)Z_V - (A_VB_V - B_V^2 - B_V^3) = 0$ ...Eq.13
Calculate the following
ϕ_i^L with
$\ln\phi_i^L = \left(\frac{b_i}{b}\right)_L(Z_L-1) - \ln(Z_L-B_L) - \frac{A_L}{B_L}\left[2\left(\frac{a_i}{a}\right)_L^{0.5} - \left(\frac{b_i}{b}\right)_L\right]\ln\left(1+\frac{B_L}{Z_L}\right)$ ...Eq.14
ϕ_c^i with $y_i = \frac{z_iK_i}{1+\frac{V}{F}(K_i-1)}$ ...Eq.7
$\ln\phi_i^V = \left(\frac{b_i}{b}\right)_V(Z_V-1) - \ln(Z_L-B_V) - \frac{A_V}{B_V}\left[2\left(\frac{a_i}{a}\right)_V^{0.5} - \left(\frac{b_i}{b}\right)_V\right]\ln\left(1+\frac{B_V}{Z_V}\right)$ ...Eq.15
Given $\left(\frac{a_i}{a}\right)_L^{0.5} = \frac{\propto_i^{0.5}{}^{T_{ci}}/_{P_{ci}}{}^{0.5}}{\sum_{i=1}^{n}x_i\propto_i^{0.5}{}^{T_{ci}}/_{P_{ci}}{}^{0.5}}$, $\left(\frac{a_i}{a}\right)_V^{0.5} = \frac{\propto_i^{0.5}{}^{T_{ci}}/_{P_{ci}}{}^{0.5}}{\sum_{i=1}^{n}y_i\propto_i^{0.5}{}^{T_{ci}}/_{P_{ci}}{}^{0.5}}$,
$\left(\frac{b_i}{b}\right)_L = \frac{{}^{T_{ci}}/_{P_{ci}}}{\sum_{i=1}^{n}x_i\,{}^{T_{ci}}/_{P_{ci}}}$, $\left(\frac{b_i}{b}\right)_V = \frac{{}^{T_{ci}}/_{P_{ci}}}{\sum_{i=1}^{n}y_i\,{}^{T_{ci}}/_{P_{ci}}}$
K_i with $K_i = \frac{\phi_i^L}{\phi_i^V}$ ...Eq.16
$\sum_{i=1}^{n}\left[\left(\frac{K_i^C}{K_i^A}\right)-1\right]^2 > 0.0001$
No
Print final results
Yes
Iteration > 1000
No
Iteration = Iteration +1
$K_i^A = K_i^C$ for all i
Yes
Print Warning, Stop Calculations

Procedure for calculating gas and oil phases from Equilibrium ratios

Once equilibrium ratios have been solved for, the volumes of each component

Oil Phase:

$$x_i = \left(\frac{z_i \cdot n_t}{n_L + n_g \cdot K_i} \right)$$

Gas Phase:

$$y_i = \left(\frac{z_i \cdot n_t}{n_g + \frac{n_L}{K_i}} \right)$$

Calculation of C_{7+} Properties

The 12 component composition that Piper uses has one pseudo-component, the C_{7+}fraction.The C_{7+}fraction is intended to represent the combined influence of all components greater than C_7in the flash calculation process. Therefore a set of equivalent pseudo-properties need to be calculated for the component. These are described below:

The parameter , which is used in the Standing Equilibrium ratio correlation can be calculated as follows (from PVT and Phase Behavior of Petroleum Fluids - Danesh):

$$\alpha' = 563 + 180n - 2.364n^2$$

Where n is calculated as follows (from PVT and Phase Behavior of Petroleum Fluids - Danesh):

$$n = \frac{M_{c7+} - 2}{14}$$

Boiling Point

The boiling point can be calculated from the Soreide correlation (from Phase Behavior – Whitson):

$$T_b = 1928.3 - (1.695 \times 10^5) \cdot M_{C7+}{}^{-0.03522} \gamma_{C7+}{}^{3.266} \cdot \exp[-(4.922 \times 10^{-03}) M_{c7+} - 4.7685 \gamma_{c7+} + (3.462 \times 10^{-03}) M_{c7+} \gamma_{c7+}$$

Critical Properties

Once the boiling point is calculated the critical properties can be calculated for each pseudo-component. The calculation of critical temperature and pressure follows the process described by Twu. The process involves a number of calculations but they aren't difficult (all of the steps below are from Phase Behavior – Whitson) :

1. Calculate T_{cP} for each pseudo-component:

$$T_{cP} = T_b[0.533272 + (0.191017 \times 10^{-03})T_b + (0.779681 \times 10^{-07})T_b{}^2 - (0.284376 \times 10^{-10})T_b{}^3 + \frac{(0.959468 \times 10^2)}{(0.01T_b)^{13}}]^{-1}$$

2. Calculate α for each pseudo-component:

$$\alpha = 1 - \frac{T_b}{T_{cP}}$$

3. Calculate paraffin specific gravity γ_p for each pseudo-component:

$$\gamma_p = 0.843593 - 0.128624\alpha - 3.36159\alpha^3 - 13749.5\alpha^{12}$$

4. Calculate paraffin critical volume v_{cP} for each pseudo-component:

$$v_{cP} = [1 - 0.419869 - 0.505839\alpha - 1.56436\alpha^3 - 9481.7\alpha^{14}]^{-8}$$

5. Calculate paraffin critical pressure p_{cP} for each pseudo-component:

$$p_{cP} = [3.83354 + 1.19629\alpha^{0.5} + 34.8888\alpha + 36.1952\alpha^2 + 104.193\alpha^4]^2$$

6. Calculate $\Delta\gamma_T$ for each pseudo-component:

$$\Delta\gamma_T = \exp[5(\gamma_p - \gamma)] - 1$$

7. Calculate $\Delta\gamma_v$ for each pseudo-component:

$$\Delta\gamma_v = \exp[4(\gamma_p^2 - \gamma^2)] - 1$$

8. Calculate $\Delta\gamma_p$ for each pseudo-component:

$$\Delta\gamma_p = \exp[0.5(\gamma_p - \gamma)] - 1$$

9. Calculate f_T for each pseudo-component:

$$f_T = \Delta\gamma_T\left[\frac{-0.362456}{T_b^{0.5}} + \left(0.0398285 - \frac{0.948125}{T_b^{0.5}}\right)\Delta\gamma_T\right]$$

10. Calculate f_v for each pseudo-component:

$$f_v = \Delta\gamma_v\left[\frac{0.466590}{T_b^{0.5}} + \left(-0.182421 + \frac{3.01721}{T_b^{0.5}}\right)\Delta\gamma_v\right]$$

11. Calculate f_p for each pseudo-component:

$$f_p = \Delta\gamma_p\left[\left(2.53262 - \frac{46.1955}{T_b^{0.5}} - 0.00127885T_b\right) + \left(-11.4277 + \frac{252.14}{T_b^{0.5}} + 0.00230535T_b\right)\Delta\gamma_p\right]$$

12. Calculate T_c for each pseudo-component:

$$T_c = T_{cP}\left(\frac{1 + 2f_T}{1 - 2f_T}\right)^2$$

13. Calculate V_c for each pseudo-component:

$$V_c = V_{cP}\left(\frac{1+2f_v}{1-2f_v}\right)^2$$

14. Calculate p_c for each pseudo-component:

$$p_c = p_{cP}\cdot\frac{T_c}{T_{cP}}\cdot\frac{V_{cP}}{V_c}\left(\frac{1+2f_p}{1-2f_p}\right)^2$$

Acentric Factor

The acentric factor can be calculated from the Lee-Kesler correlations:

1. Calculate the reduced normal boiling point T_{br} for the C_{7+} fraction:

$$T_{br} = \frac{T_b}{T_c}$$

2. If T_{br} < 0.8, then calculate the acentric factor ω for each pseudo-component using the following:

$$\omega = \frac{-\ln\left(\frac{p_c}{14.7}\right) - 5.92714 + 6.09648T_{br}^{-1} + 1.28862\ln(T_{br}) - 0.169347T_{br}^{6}}{15.2518 - 15.6875T_{br}^{-1} - 13.4721\ln(T_{br}) + 0.43577T_{br}^{6}}$$

3. If T_{br} 0.8, then calculate the acentric factor ω for each pseudo-component using the following:

$$\omega = -7.904 + 0.1352\frac{T_b^{1/3}}{\gamma} - 0.007465\left(\frac{T_b^{1/3}}{\gamma}\right)^2 + 8.359T_{br} + \left(1.408 - 0.01063\frac{T_b^{\frac{1}{3}}}{\gamma}\right)T_{br}^{-1}$$

Post-phase calculation properties

Once the phase calculations (either Peng-Robinson or Wilson) has been completed, fluid properties for both the gas and oil phases need to be calculated. This section describes the methods used to calculate each property.

Calculation of Oil Density for Compositional Model

The Standing-Katz method with the Vogel-Yarborough treatment of Nitrogen is used to calculate the density of the oil. Corrections made include nitrogen, ethane density, and methane density.

1. Add the weight fraction of the nitrogen to the weight fraction of the ethane to form a new ethane content for the purpose of this calculation

2. Calculate the molecular weight of the C_2 to C_{7+} with the following summations:

$$M = \sum_{i=C2}^{C7+} x_i \cdot MW_i$$

3. Calculate the molar volume of the C_2 to C_{7+} with the following summation, where (ρ_i) is the liquid density of each component:

$$v = \sum_{i=C2}^{C7+} \frac{x_i \cdot MW_i}{\rho_i}$$

4. Calculate the density of the liquid

$$\rho_{C2+} = \frac{M}{v}$$

5. Calculate the density of the C_2

$$\rho_{C2} = 15.3 + 0.3167\rho_{C2+}$$

$$this\ equation\ should\ be\ valid\ as\ long\ as\ density\ is\ in\ lbm/ft^3$$

6. Calculate the molecular weight of the C_2 to C_{7+} components with the following summations:

$$M = \sum_{i=C2}^{C7+} x_i \cdot MW_i$$

7. Calculate the molar volume of the C_2 to C_{7+} components with the following summation, where (ρ_i) is the liquid density of each component except for ethane which has its density replaced with the density calculated in the ρ_{C2+} calculation above

$$v = \sum_{i=C2}^{C7+} \frac{x_i \cdot MW_i}{\rho_i}$$

8. Calculate the density of the liquid

$$\rho = \frac{M}{v}$$

9. Calculate the density of the C_1

$$\rho_{C1} = 0.312 + 0.45\rho$$

$$this\ equation\ should\ be\ valid\ as\ long\ as\ density\ is\ in\ lbm/ft^3$$

10. Calculate the molecular weight of the C_1 to C_{7+} components with the following summations:

$$M = \sum_{i=C1}^{C7+} x_i \cdot MW_i$$

11. Calculate the molar volume of the C_1 to C_{7+} components with the following summation, where (ρ_i) is the liquid density of each component except for ethane which has its density replaced with the density calculated in the ρ_{C2+} calculation above

$$v = \sum_{i=C1}^{C7+} \frac{x_i \cdot MW_i}{\rho_i}$$

12. Calculate the density of the liquid

$$\rho = \frac{M}{v}$$

The Vogel corrections are applied to Standing-Katz when the in-situ oil density is required.

Calculation of Oil Viscosity for Compositional Model

The Lorenz, Bray and Clark correlation is used to calculate compositional oil viscosity.

1. Calculate the coefficients of the Lorenz, Bray and Clark equation

$$a_0 = 0.1023$$
$$a_1 = 0.023364$$
$$a_2 = 0.058533$$
$$a_3 = -0.040758$$
$$a_4 = 0.0093724$$

2. Calculate the mixture viscosity parameter

$$\xi_m = \frac{5.4402\left(T_{pc}{}^{1/6}\right)}{M^{0.5}{p_{pc}}^{2/3}}$$

3. Calculate the V_{c7+} term required to calculate reduced oil density

$$V_{c7+} = 21.573 + 0.015122M_{c7+} - 27.656\gamma_{c7+} + 0.070615M_{c7+}\gamma_{c7+}$$

4. Calculate the reduced oil density (ρ_r):

$$\rho_r = \frac{\rho_o}{M}\left[\sum_{\substack{i=1 \\ i \neq c7+}}^{n}(x_i M_i V_{ci}) + (x_{c7+}V_{c7+})\right]$$

5. Calculate ξ_i, which will be used in the calculation of μ_i

$$\xi_i = \frac{5.4402\left(T_{ci}{}^{1/6}\right)}{M_i^{0.5}{p_{ci}}^{2/3}}$$

6. Calculate T_{ri} for each component of Table 2

$$T_{ri} = \frac{T}{T_{ci}}$$

If $T_{ri} \leq 1.5$:

$$\mu_i = \frac{34 \times 10^{-5}(T_{ri})^{0.94}}{\xi_i}$$

If $T_{ri} > 1.5$:

$$\mu_i = \frac{17.78 \times 10^{-5}(4.58T_{ri} - 1.67)^{0.625}}{\xi_i}$$

7. Calculate the viscosity of the live oil at atmospheric pressure (μ_{oL})

$$\mu_{oL} = \frac{\sum_{i=1}^{n}\left(x_i \mu_i M_i^{0.5}\right)}{\sum_{i=1}^{n}\left(x_i M_i^{0.5}\right)}$$

8. Use the Lorenz, Bray and Clark equation used to calculate viscosity

$$\mu = \mu_{oL} + \xi_m^{-1}(a_0 + a_1\rho_r + a_2\rho_r^2 + a_3\rho_r^3 + a_4\rho_r^4)^4 - 0.0001$$

Gas Compressibility

When Peng-Robinson is selected, the gas compressibility comes directly from the equation of state solution.

When Wilson is selected, gas compressibility is calculated using BWR after converting the full composition into an equivalent gas gravity.

Gas Viscosity

Gas viscosity for both Peng-Robinson and Wilson are calculated using the Carr et al. gas viscosity correlation.

Exclusion of Water from the Compositional Model

Water is not currently considered in the equation of state routine. The exclusion of water was done in the interests of minimizing solution time of the equation of state model, and while keeping in mind that the intent of Piper is to perform pipeline hydraulics calculations, which tend to have only a secondary and tertiary link to the impact of water of condensation and gas dissolved in water.

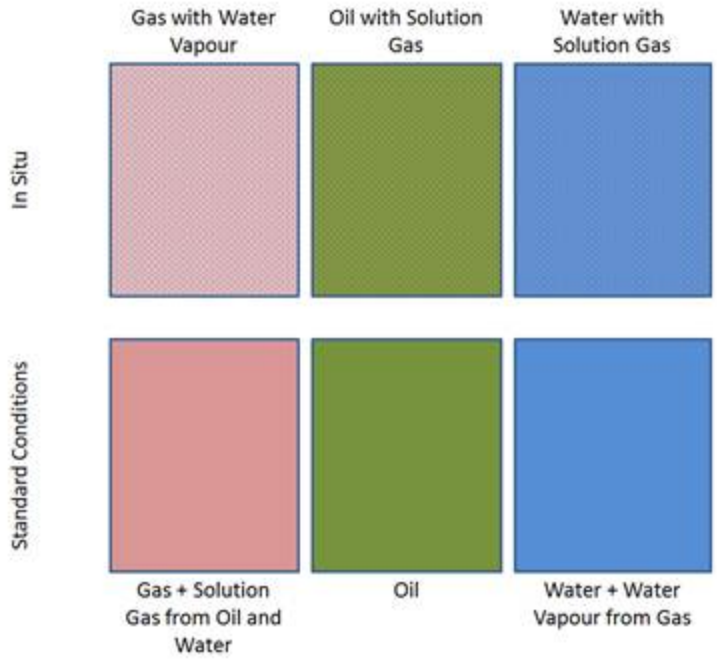
Instead of including water in the equation of state model black oil like adjustments are made to the gas molar volume and water volume.

Adjustments to dissolved gas in the water are made using the Meehan correlation prior to the equation of state calculation, which therefore effectively removes the gas volume that is dissolved in the water phase.

Adjustments to evaporated water in the gas are made using the Bukacek correlation post-phase volume calculations.

Black Oil in Piper allows for calculation of the change in fluid volumes between in-situ and standard conditions.

When using the Black Oil phase volume calculations, each node in the system will have gas, oil, and water reported in standard conditions and in-situ volumes. While the total standard conditions volumes for each fluid will be consistent throughout the system, the in-situ volumes account for the changing pressure and temperature and the effect on free gas and water relative to those in solution or vapour phase. The image below illustrates the comparison of standard conditions and in-situ volumes.



The change in free gas and water for in-situ volumes between two nodes are determined from the R_{so}, R_{sw}, and W_{oC} for the pressure and temperature of each node. When the change in pressure and temperature between two nodes result in an increasing R_{so} or R_{sw}, there will be less free gas at the in-situ conditions of the second node.

The equations used are listed below. A single equation for each R_{sw} and W_{oC} are provided. The equation used for R_{so} is dependent on the correlation selected for Oil PVT in the Correlations dialog.

Solution Gas Oil Ratio

Vasquez & 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.

$$R_{so} = C_1 \gamma_{g100} p^{C_2} exp\left[C_3\left(\frac{\gamma_{API}}{T + 459.67}\right)\right]$$

$$\gamma_{g100} = \gamma_g\left(1.0 + 5.912x10^{-5}\gamma_{API}T_{sep}log\frac{p_{sep}}{114.7}\right)$$

Coefficient	API < 30	API > 30
C_1	0.0362	0.0178
C_2	1.0937	1.1870
C_3	25.7245	23.931

De Ghetto et al

$$R_{so} = \frac{\gamma_g(p_{sep})*p^{1.2057}}{56.434} * 10^{10.9267} * \frac{\gamma_{API}}{T + 459.67}$$

$$\gamma_g(p_{sep}) = \gamma_g\left(1 + 0.5912 * \gamma_{API} * T_{sep} * log\left(\frac{p_{sep}}{114.7}\right) * 10^{-4}\right)$$

The above equations are suitable for oils with gravity of 10° < API < 22.3°. A modified version of the De Ghetto equations exists for oils below 10°, however this is outside the range of Piper intended use.

Glaso

This correlation is based on North Sea crude-oil data. It is suitable for oil gravity of 22° < API < 48° and believed to be less accurate for R_{so} > 1400 scf/STBO. This equation cannot be used for p > 19285 psia as a result of the p_b^* equation.

$$R_{so} = \gamma_g\left(\frac{{\gamma_{API}}^{0.989}}{T^{0.172}} p_b^*\right)^{1.2255}$$

$$p_b^* = 10^{\left(2.8869 - [14.1811 - 3.3093 log(p)]^{0.5}\right)}$$

Hanafy et al

This correlation has been developed independent of oil gravity and temperature. Comparisons have demonstrated that it is more applicable to light oils.

$$R_{so} = -49.069 + 0.312p$$

R_{so} = 0 when p 157.28 psia.

Standing

Applicable for oil gravity of 16° < API < 64°

$$R_{so} = \gamma_g\left[\left(\frac{p}{18.2} + 1.4\right) 10^{0.0125\gamma_{API} - 0.00091T}\right]^{1.2048}$$

Petrosky and Farshad

Applicable for oil gravity of 16° < API < 45°. For Gulf of Mexico oils, it has been found to provide improved results over Standing, Vasquez and Beggs, and Glaso.

$$R_{so} = \left(\left(\frac{p}{112.727} + 12.34\right) * {\gamma_g}^{0.8439} * 10^{x}\right)^{1.73184}$$

$$x = 7.916 * 10^{-4} * \gamma_{API}{}^{1.541} - 4.561 * 10^{-5} * T^{1.3911}$$

Velarde at al

Applicable for oil gravity of 12° < API < 55°

$$R_{so} = \left(\frac{\left(\frac{p_b}{1091.47}\right)^{\frac{1}{5.354891}} + 0.740152}{\gamma_g{}^{-0.161488} * 10^{x}} \right)^{\frac{1}{0.081465}}$$

$$p_b = 1091.47\left(R_{sb}{}^{0.081465} \gamma_g{}^{-0.161488} * 10^{x} - 0.740152\right)^{5.354891}$$

$$x = 0.013098 * T^{0.282372} - 8.2 * 10^{-6} * \gamma_{API}{}^{2.176124}$$

Solution Gas Water Ratio

$$R_{sw} = (2.12 + 3.45x10^{-3}T - 3.59x10^{-5}T^2) + (0.0107 - 5.26x10^{-5}T + 1.48x10^{-7}T^2) * p + (-8.75x10^{-7} + 3.9x10^{-9}T - 1.02x10^{-11}T^2) * p^2$$

The above equation describes gas solubility in pure water. The following equation corrects the R_{sw} for salinity.

$$(R_{sw})_b = R_{sw} C_s$$

$$C_s = 1.0 - (0.0753 - 0.000173T)S$$

Water of Condensation

$$W_{oC} = \frac{A(T)/(p + B(T))}{62.4 * 5.615}$$

$$logA(T) = 10.9351 - \frac{2949.05}{T + 459.67} - \frac{318045}{(T + 459.67)^2}$$

$$logB(T) = 6.69449 - \frac{3083.87}{T + 459.67}$$

Nomenclature

	Description	Units
γ_g	Gas gravity	
γ_{API}	API oil gravity	°API
p	System pressure	psia

p_{sep}	Separator pressure	psia
R_{so}	Solubility of gas in oil	scf/STBO
R_{sw}	Solubility of gas in water	scf/STBW
S	Salinity of water	Weight % of NaCl
T	Temperature	°F
T_{sep}	Separator temperature	°F
W_{oC}	Water of condensation	STBW/MMscf

General fluid correlations

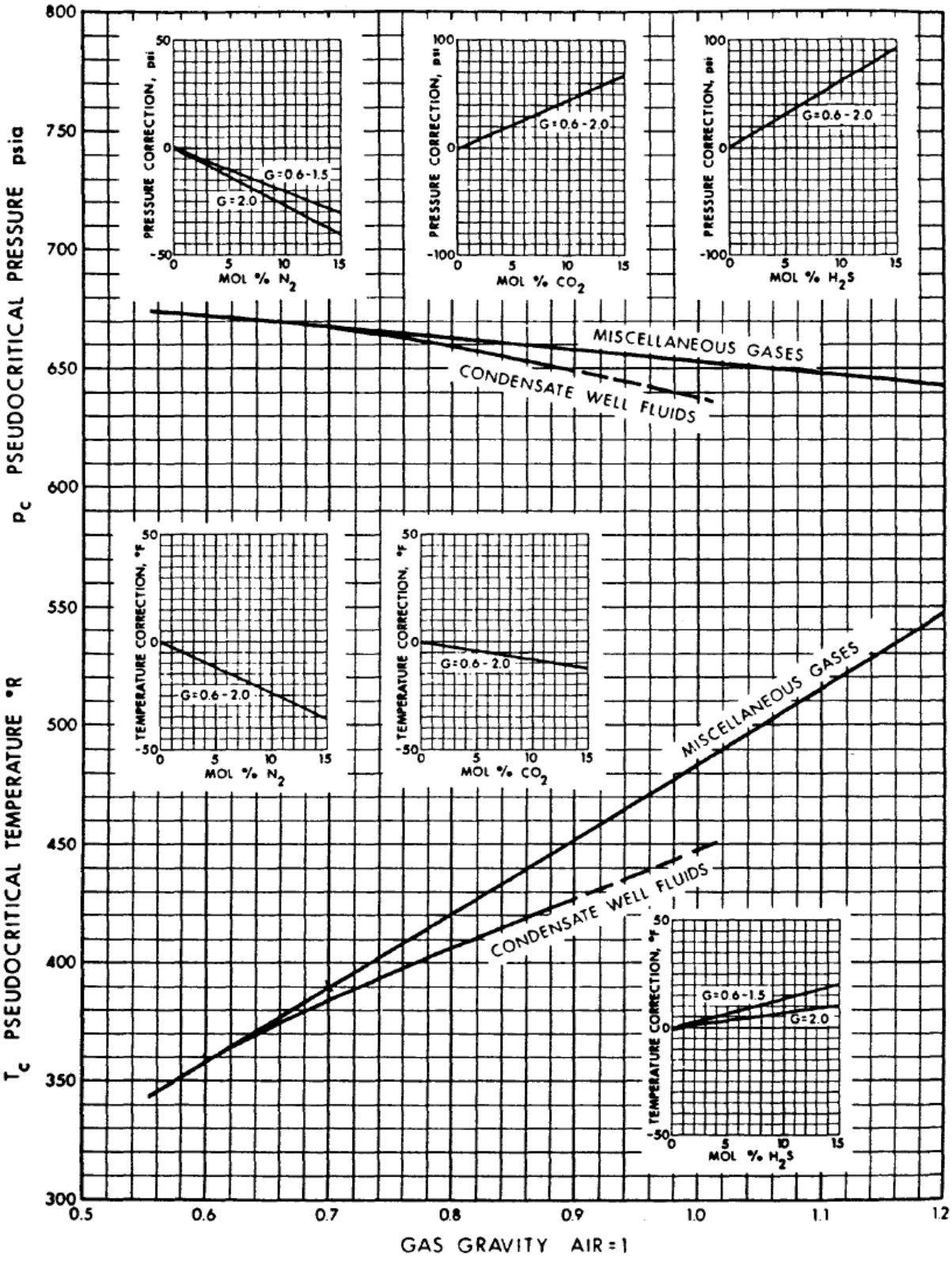
Gas PVT correlations

BWR

Z factor, viscosity, and other gas properties have been correlated accurately with corresponding-states principles, where the property is correlated as a function of reduced pressure and temperature.

pr = p / pc and Tr = T / Tc

In the BWR methodology, pc and Tc for gas mixtures are determined from the gas gravity from the following relationship.


p_c PSEUDOCRITICAL PRESSURE psia
T_c PSEUDOCRITICAL TEMPERATURE °R
GAS GRAVITY AIR = 1
MISCELLANEOUS GASES
CONDENSATE WELL FLUIDS
PRESSURE CORRECTION, psi
TEMPERATURE CORRECTION, °F
G = 0.6 - 1.5
G = 2.0
MOL % N_2
MOL % CO_2
MOL % H_2S

The upper curve for each is used for dry gas and the lower curve for wet gas. Corrections for non-hydrocarbon components are also provided as insets in the plot.

BWR determination of Z

$$Z = 1 + \left(A_1 + \frac{A_2}{T_r} + \frac{A_3}{T_r^3}\right)\rho_r + \left(A_4 + \frac{A_5}{T_r}\right)\rho_r^2 + A_5 A_6 \frac{\rho_r^5}{T_r} + A_7 \frac{\rho_r^2}{T_r^3}(1 + A_8\rho_r^2)e^{-A_8\rho_r^2}$$

$$\rho_r = 0.27\frac{p_r}{ZT_r}$$

A_1 = 0.31506237	A_2 = -1.04670990	A_3 = -0.57832729
A_4 = 0.53530771	A_5 = -0.61232032	A_6 = -0.10488813
A_7 = 0.68157001	A_8 = 0.68446549	

Correcting for Sour Gas

$$\varepsilon_3 = 120(A^{0.9} - A^{1.6}) + 15\left(B^{0.5} - B^{4.0}\right)$$

A = sum of mole fractions of CO_2 and H_2S

B = mole fraction of H_2S

$$T_c' = T_c - \varepsilon_3$$

$$p_c' = \frac{p_c T_c'}{T_c + B(1 - B)\varepsilon_3}$$

Compressibility

$$c_r = \frac{1}{p_r} - \frac{0.27}{Z^2 T_r}\left[\frac{(\partial Z/\partial p_r)_{T_r}}{1 + {}^{\rho_r}/_{Z}\,(\partial Z/\partial p_r)_{T_r}}\right]$$

$$\left(\frac{\partial Z}{\partial p_r}\right)_{T_r} = \left(A_1 + \frac{A_2}{T_r} + \frac{A_3}{T_r^3}\right) + 2\left(A_4 + \frac{A_5}{T_r}\right)\rho_r + 5A_5A_6\frac{\rho_r^4}{T_r} + 2A_7\frac{\rho_r}{T_r^3}(1 + A_8\rho_r^2 - A_8^2\rho_r^4)e^{-A_8\rho_r^2}$$

$$c_r = cp_c$$

Piper Detail

Similar to the calculations detailed above, with the Piper Detail correlation gas properties are determined from the Tc and pc of the gas mixture. When using Piper Detail, the user provides a detailed composition of the gas. In this case, rather than using a tabular/graphical approach to determining Tc and pc, they can be determined directly.

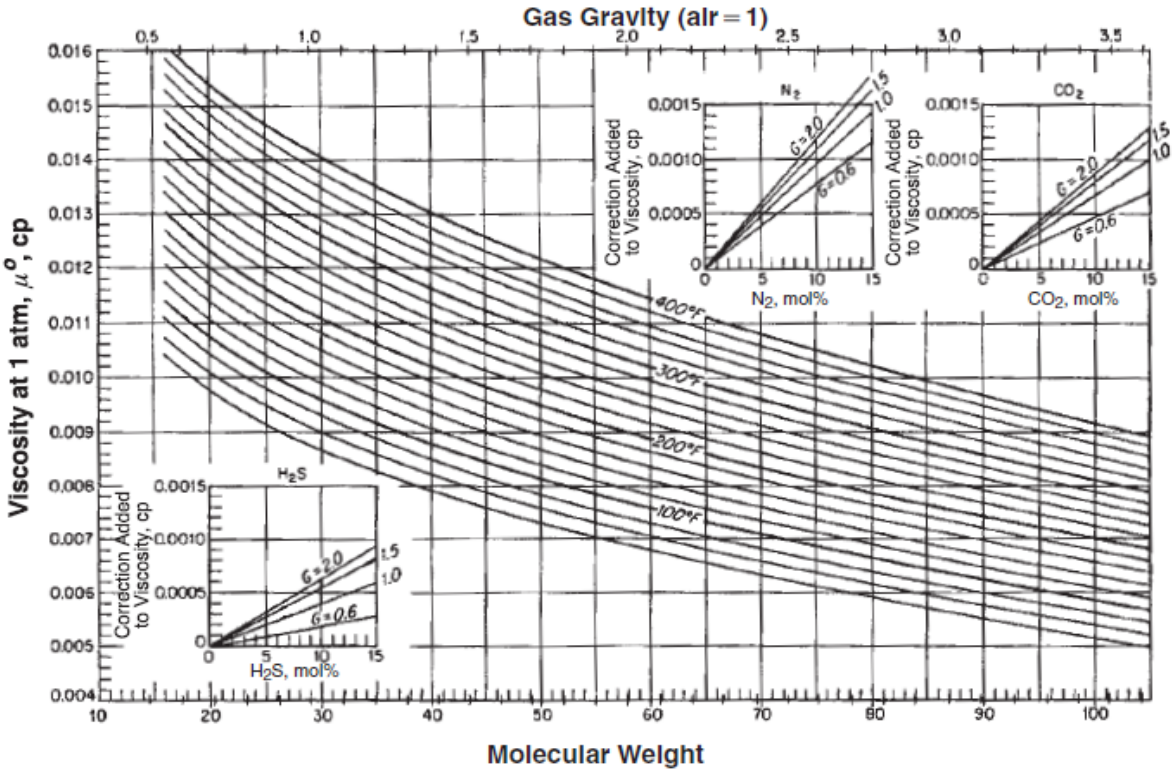
$$T_c = \sum_i x_i T_{ci}$$

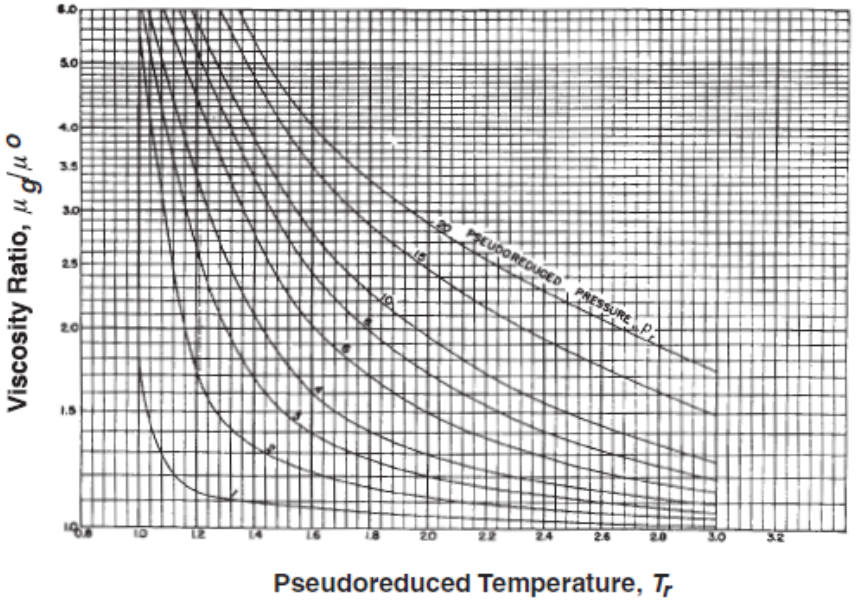
$$p_c = \sum_i x_i p_{ci}$$

Gas viscosity correlations

Gas viscosity correlations for Carr et al., Lee, Gonzalez, and Eakin, and Lucas are shown below.

Carr et al


Gas Gravity (air = 1)
Viscosity at 1 atm, μ^o, cp
Molecular Weight
400°F
300°F
200°F
100°F
Correction Added to Viscosity, cp
N_2
CO_2
H_2S
N_2, mol%
CO_2, mol%
H_2S, mol%
G = 2.0
1.5
1.0
G = 0.6


Viscosity Ratio, $\mu g/\mu^o$
Pseudoreduced Temperature, T_r
PSEUDOREDUCED PRESSURE, p_r

Lee, Gonzalez, and Eakin

$$\mu_g = A_1 * 10^{-4} e^{\left(A_2 \rho_g{}^{A_3}\right)}$$

$$A_1 = \frac{\left(9.379 + 0.1607 M_g\right) T^{1.5}}{209.2 + 19.26 M_g + T}$$

$$A_2 = 3.448 + \frac{986.4}{T} + 0.01009 M_g$$

$$A_3 = 2.447 - 0.2224 A_2$$

Lucas

$$\frac{\mu_g}{\mu_{gsc}} = 1 + \frac{A_1 {p_{pr}}^{1.3088}}{A_2 {p_{pr}}^{A_5} + \left(1 + A_3 {p_{pr}}^{A_4}\right)^{-1}}$$

$$A_1 = \frac{1.245 * 10^{-3} e^{5.1726 {T_{pr}}^{-0.3286}}}{T_{pr}}$$

$$A_2 = A_1\left(1.6553 T_{pr} - 1.2723\right)$$

$$A_3 = \frac{0.4489 e^{3.0578 {T_{pr}}^{-37.7332}}}{T_{pr}}$$

$$A_4 = \frac{1.7368 e^{2.231 {T_{pr}}^{-7.6351}}}{T_{pr}}$$

$$A_5 = 0.9426 e^{-0.1853 {T_{pr}}^{0.4489}}$$

$$\mu_{gsc}\epsilon = 0.807 {T_{pr}}^{0.618} - 0.357 e^{-0.449 T_{pr}} + 0.340 e^{-4.058 T_{pr}} + 0.018$$

$$\epsilon = 9490 \left(\frac{T_{pc}}{M^3 {p_{pc}}^4}\right)^{\frac{1}{6}}$$

Oil PVT correlations

Vasquez & 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.

Bubblepoint Pressure

$$p_b = \left(\frac{R_{so}}{C_1 \gamma_g e^{C_3 \left(\frac{\gamma_{API}}{T+459.67} \right)}} \right)^{\frac{1}{C_2}}$$

Solution Gas Oil Ratio

$$R_{so} = C_1 \gamma_{g100} p^{C_2} exp\left[C_3 \left(\frac{\gamma_{API}}{T + 459.67} \right) \right]$$

$$\gamma_{g100} = \gamma_g \left(1.0 + 5.912x10^{-5} \gamma_{API} T_{sep} log \frac{p_{sep}}{114.7} \right)$$

Oil FVF – Saturated Oil

$$B_o = 1 + A_1 R_{so} + A_2 (T - 60) \left(\frac{\gamma_{API}}{\gamma_g} \right) + A_3 (T - 60) \left(\frac{\gamma_{API}}{\gamma_g} \right)$$

Oil FVF – Undersaturated Oil

$$B_o = B_{ob} e^{c_o (p_b - p)}$$

Compressibility – Saturated Oil

$$c_o = \frac{-1433 + 5R_{sb} + 17.2T - 1180\gamma_g + 12.61\gamma_{API}}{p * 10^5} + \frac{B_g}{5.6145835B_o} * \frac{dR_{so}}{dp}$$

Compressibility – Undersaturated Oil

$$c_o = \frac{-1433 + 5R_{sb} + 17.2T - 1180\gamma_g + 12.61\gamma_{API}}{p * 10^5}$$

Coefficient	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
A_1	$4.677*10^{-4}$	$4.670*10^{-4}$
A_2	$1.751*10^{-5}$	$1.100*10^{-5}$
A_3	$-1.811*10^{-8}$	$1.377*10^{-9}$
C_1	0.0362	0.0178
C_2	1.0937	1.1870
C_3	25.7245	23.931

De Ghetto et al

These equations are suitable for oils with gravity of 10° < API < 22.3°. A modified version of the De Ghetto equations exists for oils below 10°, however this is outside the range of Piper™ intended use and the equations are not listed.

Bubblepoint Pressure

$$p_b = \left(\frac{56.434 R_{so}}{\gamma_{g(p_{sep})} * 10^{10.9267} \left(\frac{\gamma_{API}}{T + 459.67} \right)} \right)^{\frac{1}{1.2057}}$$

$$\gamma_{g(p_{sep})} = \gamma_g \left(1 + 0.5912 \gamma_{API} T_{sep} log \left(\frac{p_{sep}}{114.7} \right) * 10^{-4} \right)$$

Solution Gas Oil Ratio

$$R_{so} = \frac{\gamma_{g(p_{sep})} * p^{1.2057}}{56.434} * 10^{10.9267} * \frac{\gamma_{API}}{T + 459.67}$$

Oil FVF – Saturated Oil

$$B_o = 1 + A_1 R_{so} + A_2 (T - 60) \left(\frac{\gamma_{API}}{\gamma_g} \right) + A_3 R_{so} (T - 60) \left(\frac{\gamma_{API}}{\gamma_g} \right)$$

$A_1 = 4.677 * 10^{-4}$

$A_2 = 1.751 * 10^{-5}$

$A_3 = -1.811 * 10^{-8}$

Oil FVF – Undersaturated Oil

$$B_o = B_{ob} e^{c_o (p_b - p)}$$

Compressibility – Saturated Oil

$$c_o = \frac{-2841.8 + 2.9646R_{sb} + 25.5439T - 1230.5\gamma_{g(p_{sep})} + 41.91\gamma_{API}}{p * 10^5} + \frac{B_g}{5.6145835B_o} * \frac{dR_{so}}{dp}$$

Compressibility – Undersaturated Oil

$$c_o = \frac{-2841.8 + 2.9646R_{sb} + 25.5439T - 1230.5\gamma_{g(p_{sep})} + 41.91\gamma_{API}}{p * 10^5}$$

Glaso

This correlation is based on North Sea crude-oil data. It is suitable for oil gravity of 22° < API < 48° and believed to be less accurate for Rso > 1400 scf/STBO. This equation cannot be used for p > 19285 psia as a result of the pb* equation.

Bubblepoint Pressure

$$log(p_b) = 1.7669 + 1.7447log(x) - 0.30218log(x)^2$$

$$x = \left(\frac{R_{so}}{\gamma_g}\right)^{0.816} \frac{T^{0.172}}{{\gamma_{API}}^{0.989}}$$

Solution Gas Oil Ratio

$$R_{so} = \gamma_g \left(\frac{{\gamma_{API}}^{0.989}}{T^{0.172}} p_b^*\right)^{1.2255}$$

$$p_b^* = 10^{(2.8869-[14.1811-3.3093log(p)]^{0.5})}$$

Oil FVF – Saturated Oil

$$log(B_o - 1) = -6.58511 + 2.91329log(y) - 0.27683log(y)^2$$

$$y = R_{so}\left(\frac{\gamma_g}{\gamma_o}\right)^{0.526} + 0.968T$$

Oil FVF – Undersaturated Oil

$$B_o = B_{ob}e^{c_o(p_b-p)}$$

Hanafy et al

This correlation has been developed independent of oil gravity and temperature. Comparisons have demonstrated that it is more applicable to light oils.

Bubblepoint Pressure

$$p_b = 3.205R_{so} + 157.27$$

Solution Gas Oil Ratio

$$R_{so} = -49.069 + 0.312p$$

R_{so} = 0 when p ≤ 157.28 psia

Oil FVF – Saturated Oil

$$B_o = 0.0006R_{so} + 1.079$$

Oil FVF – Undersaturated Oil

$$B_o = B_{ob}e^{c_o(p_b - p)}$$

Density – Saturated Oil

$$\rho_o = \left(2.366 - \frac{1.358}{B_o}\right)^{-1}$$

Density – Undersaturated Oil

$$\rho_o = \rho_{ob}e^{c_o(p_b - p)}$$

Compressibility – Saturated Oil

$$c_o = e^{\left(\frac{2.582}{\rho_{ob}} - 0.99\right)} * 10^{-6} + \frac{B_g}{5.6145835 B_o} * \frac{dR_{so}}{dp}$$

dR_{so} / dp is from Vasquez and Beggs

Compressibility – Undersaturated Oil

$$c_o = e^{\left(\frac{2.582}{\rho_{ob}} - 0.99\right)} * 10^{-6}$$

Standing

Applicable for oil gravity of 16° < API < 64°

Bubblepoint Pressure

$$p_b = 18.2\left(\left(\frac{R_{so}}{\gamma_g}\right)^{0.83} * \frac{10^{0.00091T}}{10^{0.0125\gamma_{API}}} - 1.4\right)$$

Solution Gas Oil Ratio

$$R_{so} = \gamma_g\left[\left(\frac{p}{18.2} + 1.4\right)10^{0.0125\gamma_{API} - 0.00091T}\right]^{1.2048}$$

Oil FVF

Saturated Oil

$$B_o = 0.972 + 1.47 * 10^{-4}\left(R_{so}\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25T\right)^{1.175}$$

Undersaturated Oil

$$B_o = B_{ob}e^{c_o(p_b - p)}$$

The oil compressibility in this equation is obtained from the Vasquez and Beggs correlation.

Petrosky and Farshad

Applicable for oil gravity of 16° < API < 45°. For Gulf of Mexico oils, it has been found to provide improved results over Standing, Vasquez and Beggs, and Glaso.

Bubblepoint Pressure

$$p_b = 112.727\left(\frac{{R_{so}}^{0.5774}}{{\gamma_g}^{0.8439}} * 10^x - 12.34\right)$$

$$x = 4.561 * 10^{-5} T^{1.3911} - 7.916 * 10^{-4} {\gamma_{API}}^{1.541}$$

Solution Gas Oil Ratio

$$R_{so} = \left(\left(\frac{p}{112.727} + 12.34\right) * {\gamma_g}^{0.8439} * 10^x\right)^{1.73184}$$

$$x = 7.916 * 10^{-4} * {\gamma_{API}}^{1.541} - 4.561 * 10^{-5} * T^{1.3911}$$

Oil FVF - Saturated Oil

$$B_o = 1.0113 + 7.2046 * 10^{-5}\left({R_{so}}^{0.3738}\left(\frac{{\gamma_g}^{0.2914}}{{\gamma_o}^{0.6265}}\right) + 0.24626 T^{0.5371}\right)^{3.0936}$$

Oil FVF - Undersaturated Oil

$$B_o = B_{ob} e^{c_o(p_b - p)}$$

Compressibility - Saturated Oil

$$c_o = 1.705 * 10^{-7} {R_{sob}}^{0.69357} {\gamma_g}^{0.1885} {\gamma_{API}}^{0.3272} T^{0.6729} p^{-0.5906} + \frac{B_g}{5.6145835 B_o} * \frac{dR_{so}}{dp}$$

dR_{so} / dp is from Vasquez and Beggs

Compressibility – Undersaturated Oil

$$c_o = 1.705 * 10^{-7} {R_{sob}}^{0.69357} {\gamma_g}^{0.1885} {\gamma_{API}}^{0.3272} T^{0.6729} p^{-0.5906}$$

Applicable for $2.464*10^{-5} < c_o < 3.507*10^{-5}$

Velarde at al

Applicable for oil gravity of 12° < API < 55°

Bubblepoint Pressure

$$p_b = 1091.47\left(R_{sb}{}^{0.081465}\gamma_g{}^{-0.161488} * 10^x - 0.740152\right)^{5.354891}$$

$$x = 0.013098 * T^{0.282372} - 8.2 * 10^{-6} * \gamma_{API}{}^{2.176124}$$

Solution Gas Oil Ratio at Bubblepoint

$$R_{sob} = \left(\frac{\left(\frac{p_b}{1091.47}\right)^{\frac{1}{5.354891}} + 0.740152}{\gamma_g{}^{-0.161488} * 10^x} \right)^{\frac{1}{0.081465}}$$

Solution Gas Oil Ratio for Saturated Oil

The reduced solution gas oil ratio solution below can be used to determine the actual solution gas oil ratio (Rso in the second equation) at any pressure below the bubblepoint.

$$R_{sr} = a_1 {p_r}^{a_2} + (1 + a_1) {p_r}^{a_2}$$

$$R_{sr} = \frac{R_{so}}{R_{sob}}$$

$$p_r = \frac{p}{p_b}$$

$$a_1 = A_0 {\gamma_g}^{A_1} {\gamma_{API}}^{A_2} T^{A_3} {p_b}^{A_4}$$

$$a_2 = B_0 {\gamma_g}^{B_1} {\gamma_{API}}^{B_2} T^{B_3} {p_b}^{B_4}$$

$$a_3 = C_0 {\gamma_g}^{C_1} {\gamma_{API}}^{C_2} T^{C_3} {p_b}^{C_4}$$

$A_0 = 9.73 \times 10^{-7}$	$B_0 = 0.022339$	$C_0 = 0.725167$
$A_1 = 1.672608$	$B_1 = 1.004750$	$C_1 = 1.485480$
$A_2 = 0.929870$	$B_2 = 0.337711$	$C_2 = 0.164741$
$A_3 = 0.247235$	$B_3 = 0.132795$	$C_3 = 0.091330$
$A_4 = 1.056052$	$B_4 = 0.302065$	$C_4 = 0.047094$

Oil FVF

Saturated Oil

$$B_o = \frac{\rho_{st} + 0.01357 R_{so} \gamma_g}{\rho_{oR}}$$

$$\rho_{oR} = \rho_{bs} - \left(0.00302 + 1.505 {\rho_{bs}}^{-0.951}\right)(T - 60)^{0.938} + \left(0.0233 * 10^{-0.0161 \rho_{bs}}\right)(T - 60)^{0.475}$$

$$\rho_{bs} = \rho_{po} + \left(0.167 + 16.181 * 10^{-0.0425 \rho_{po}}\right)\left(\frac{p}{1000}\right) - 0.01\left(0.299 + 263 * 10^{-0.0603 \rho_{po}}\right)\left(\frac{p}{1000}\right)^2$$

Initial estimate of ρ_{po} is calculated using:

$$\rho_{po} = 52.8 - 0.01 R_{sob}$$

This is used for a 10 step iteration process using the following equations. The 9th and 10th iterations are averaged for a final ρpo.

$$\rho_a = -49.893 + 85.0149\gamma_g - 3.70373\gamma_g\rho_{po} + 0.047981\gamma_g{\rho_{po}}^2 + 2.98914\rho_{po} - 0.035688{\rho_{po}}^2$$

$$\rho_{po} = \frac{R_{so}\gamma_g + 4600\gamma_o}{73.71 + \frac{R_{so}\gamma_g}{\rho_a}}$$

Undersaturated Oil

$$B_o = B_{ob}e^{c_o(p_b - p)}$$

The oil compressibility in this equation is obtained from the Vasquez and Beggs correlation.

Oil Viscosity Correlations

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 data set 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.

$$\mu_{od} = 10^{10^{3.0324 - 0.02023G_T - 1.163}} - 1$$

De Ghetto et al

All correlations listed are applicable to oil gravity of 10° < API < 22.3°. De Ghetto has also developed correlations applicable to oil gravity below 10°, however this is outside the intended use of Piper and these correlations are not listed.

Dead Oil

$$log(\mu_{od} + 1) = 2.06492 - 0.0179\gamma_{API} - 0.70226 * log(T)$$

Saturated Oil

$$\mu_{os} = -0.6311 + 1.078x - 0.003653x^2$$

$$x = \left(0.2478 + 0.6144 * 10^{-0.000845R_{so}}\right) * {\mu_{od}}^{0.4731+0.5158y}$$

$$y = 10^{-0.00081R_{so}}$$

Undersaturated Oil

$$\mu_o = 0.9886\mu_{os} + 0.002763(p - p_b)\left(-0.01153{\mu_{os}}^{1.7933} + 0.0316{\mu_{os}}^{1.5939}\right)$$

Hanafy et al

Observations have demonstrated that this correlation is most appropriate for light oils.

$$\mu_o = e^{(7.296{\rho_o}^3 - 3.095)}$$

Khan et al

At bubblepoint

$$\mu_{ob} = \frac{0.09\sqrt{\gamma_g}}{\sqrt{R_{so}} * {\theta_r}^{4.5}(1-\gamma_o)^3}$$

$$\theta_r = \frac{T + 459.67}{459.67}$$

Undersaturated Oil

$$\mu_o = \mu_{ob} e^{(9.6*10^{-5}(p-p_b))}$$

Saturated Oil

$$\mu_{os} = \mu_{ob}\left(\frac{p}{p_b}\right)^{-0.14} e^{(-2.5*10^{-4}(p-p_b))}$$

Temperature calculations

Temperature at a Point

Piper will calculate the temperature of each calculation segment of pipe based on the following equation, and using the two boundary conditions (the Wellsite Line Temperature and Surroundings Temperature) specified by the user.

$$T = (T_0 - T_\infty)e^{-\pi DxU/\Sigma[\dot{m}_i C_{p,i}]} + T_\infty$$

Where:

$$\sum \dot{m}_i C_{p,i} = \dot{m}_g C_{p,g} + \dot{m}_o C_{p,o} + \dot{m}_w C_{p,w}$$

Similarly, the average temperature over a link is calculated using the following equation:

The equation for the temperature at a point in a pipe segment is shown below.

$$T = (T_0 - T_\infty)e^{-\pi DxU/\Sigma[\dot{m}_i C_{p,i}]} + T_\infty$$

Where: T_0 is the temperature at the beginning of the pipe, T is the temperature of the surroundings, D is the inner pipeline diameter, x is the pipeline distance measured from the beginning of the pipe, U is the overall heat transfer coefficient.

Where:

$$\sum \dot{m}_i C_{p,i} = \dot{m}_g C_{p,g} + \dot{m}_o C_{p,o} + \dot{m}_w C_{p,w}$$

Where: m is the total mass of each component and C is the specific heat capacity.

Mixing Temperature

Piper will calculate the temperature of the mixture at junctions with the assumption of perfect mixing of all the phases. The equation used to calculate the Mixed Temperature is as follows:

$$T = \frac{\dot{m}_1 C_{p,1} T_1 + \dot{m}_2 C_{p,2} T_2 + \ldots + \dot{m}_n C_{p,n} T_n}{\dot{m}_1 C_{p,1} + \dot{m}_2 C_{p,2} + \ldots + \dot{m}_n C_{p,n}}$$

Where 1,2…n refer to the fluid phases and fluid streams present.

Specific Heat Capacity Calculations

Each of the temperature calculations depend on the specific heat capacity of the fluids present.

For water, Piper will always assume that $C_{p,w}$ is equal to 1 Btu/lbm-°F.

The correlation for specific heat of oil was taken from the book *Multiphase Flow in Wells* (1). The correlation is shown below.

$$C_{p,o} = \frac{0.388 + 0.00045T}{\sqrt{\gamma_o}}$$

This correlation shall be used in Piper to determine the specific heat of the oil phase.

For gas, the following correlation, published in the Oil & Gas Journal (2), and is shown below.

$$C_{p,g} = \left[1.15(1.008)^T T^{-0.944} + 0.533(1.11)^{p/1000}(p/1000)^{0.0216}\right]\left[\frac{G}{0.60}\right]^{0.025}$$

This correlation is used to determine the specific heat of the gas phase.

1. **Brill, James P. and Mukherjee, Hemanta.***Multiphase Flow in Wells.* Richardson : Society of Petroleum Engineers Inc., 1999. p. 122.

2. *Correlation for Natural Gas Heat Capacity Developed.***Moshfeghian, Mahmood.** October 3, 2011, Oil & Gas Journal, Vol. 109, pp. 123-127.

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Status Window messages

These Status Window messages often require additional explanation.

"Well is not stable after 400 iterations and may not solve. This system should be reviewed."

When Piper is running a forecast, every date in the forecast period must converge before starting on the next date. By default, Piper aborts the calculations for a single date after 5,000 iterations for a smaller system with less than 500 nodes, or 10,000 iterations for a larger system. This is done to make sure that a forecast does not continue calculating forever without solving.

The status message of "well X is not stable after 400 iterations..." indicates that the forecast has passed 400 iterations (out of 5000 or more), and that specific well has not converged yet. Since we usually expect a well to converge within 400 iterations, this message is warning you that the well may never converge. In other words, because the named well has not converged in 400 iterations, it is unlikely to converge after 5,000 iterations. Piper gives you the option of manually stopping the forecast so you can investigate.

What review steps should be taken? About half the time, the well has not been set up properly, or a change was made after importing. The other half of the time, Piper will never find a solution because of Piper's model limitations affecting the well in the gathering system. Troubleshooting also depends on the type of well returning the message. If it is a conventional gas deliverability well (Wellhead Test, Wellhead C,n, Sandface C,n), then a good place to start is the Wellbore Tuning page within the Well Editor. If it is an Analytical well (imported from Harmony Enterprise™), then there are many things that should be checked.

Here is a non-comprehensive list of things to check in order of importance when troubleshooting an Analytical well:

1. Does the well forecast as expected in Harmony Enterprise?

   If the well does not forecast in Harmony Enterprise, particularly with wellhead pressures, then it will probably not forecast in Piper.

2. Are the ratios (OGR, WGR, etc.) reasonable?

   By default, the LGR values from the last date of production history are imported into Piper. If they do not match the expected trend, modify them in Piper as you see fit.

3. Has the Piper surface gathering system been calibrated?

   Calibration is one of the most important steps in building a gathering system model, and yet it is often overlooked. If you are unsure what is meant by the term calibration, we strongly

recommend attending a Piper training course (either free or paid). For an introduction to model calibration, see the Piper – Getting Started video (opens in a new web page).

4. If the gathering system model has been calibrated in the past, how long ago did this occur?

   In general, Analytical wells should be imported into a recently calibrated model to ensure that the pipeline network, facilities, and expected operating pressures are all valid. While a full recalibration is not always necessary, it is not particularly time-consuming and usually saves you some troubleshooting later. At a minimum, we recommend repeating step 3 (deliverability match) and step 4 (production history match) of the calibration process every time an Analytical well is imported.

If the model *is calibrated*, consider:

1. Are any wells set to "Reduce Rate by Percentage" in the Well Editor?

   If so, try changing it to "Add Delta P When a Segment Loads", or disabling liquid loading for that well outright.

2. Gas impurities in the Gas Composition section of the Well Editor are blank.

   Enter a valid number, or set the impurities to zero.

3. The forecast start date in Piper does not match up with the production history end date for that well.

   In general, the best practice is to do all history matching in Harmony Enterprise for all wells up to a specific date. Then, import all the wells into Piper, and set the Piper forecast start date to be the same as, or just after, the production history end date. This is highly recommended if you are doing "daily" forecasting in Piper. However, matching up the production history for all of your wells with the forecast start date is not always practical. If this applies to you, we recommend that you check the time difference and ensure that it is reasonable.

   Note: If the Piper forecast start date occurs after the production history end date for one or more wells, you need to consider the Analytical Model Gap Production settings in the Default dialog box.

4. If you are updating production history data for an existing Piper project, be aware that it may cause unexpected changes to the Analytical models.

   We recommend updating the production data in Harmony Enterprise, checking the history matches of all the Analytical models, and reconfirming your expectations of how the wells should behave when forecasted with wellhead pressure. Then, export the wells with analytical models from Harmony Enterprise, and re-import into Piper.

   Note: If you decide to import production data into Piper directly, then several of the checks-and-balances that exist in the Harmony Enterprise export process do not occur. For

example, an Analytical well needs both rates and sandface pressures to be considered valid. If only rates are imported, then the Analytical well will likely fail to converge when you attempt to forecast in Piper.

5. Using Piper to compare a forecast against production history.

   In general, we do not recommend using Piper exclusively to compare a historical forecast against known production history for the same time period. The reason is that Piper tries to use the actual data (not the calculated data) for material balance calculations and can distort the expected forecast. Instead, we recommend using the comparison plot in Harmony Enterprise, or any spreadsheet program.

6. Editing Analytical well parameters in Piper.

   In general, we always recommend creating and history-matching Analytical models in Harmony Enterprise, and then importing them into Piper. However, you can edit parameters for an Analytical well. The primary reason for this is to copy parameters from an existing Analytical well to a new "infill" well in Piper. Of course, since the parameters are editable for any well, then it is possible to create impossible scenarios. Piper has some checks to ensure that entered parameters agree with each other, but it is not a replacement for the tools in Harmony Enterprise.

7. Onstream date.

   The onstream date for the well must always match the production history start date. If there is no production history, you can leave the onstream date blank, or set it to a date in the future.

8. Wellbore configuration must be valid.

   A common scenario occurs when your actual well produces through the casing (no tubing). Since Piper must have tubing information entered, we recommend that you set your casing ID to be tubing ID in Piper. Then, set a larger tubing OD and casing ID.

9. Other things to check:

   Loop links, elevation changes, properties correlations, multiphase flow correlations, temperature, etc. Each of these items can contribute to a well not converging. It is expected that most of these issues are caught during an initial model calibration. However, there is a chance that these features can exacerbate problems with some well deliverability models. Therefore, a check may be to temporarily disable elevation changes or temperature, and see if the model converges without these added complexities. Another check may be to ensure that the correct correlations are being applied, or even to try different applicable correlations. When it comes to loop links, there is extensive information elsewhere on how to identify issues and avoid them.

"Warning: Well 'X' does not have a vertical wellbore. The wellbore has been simplified for use with Piper"

This means that Piper has automatically converted your wellbore to a type that can be use in Piper. In many cases, no action on your part is required. Of course, we recommend checking that the imported wellbore(s) are reasonable. For example, when importing a horizontal / deviated well, the values of EOT and mpp are often equal to each other, or mpp is slightly larger than EOT. If either of those values is zero / undefined, or they are significantly different, you need to investigate.

Nomenclature listings

Piper uses these nomenclature listings / variables:

Avail - available horsepower (compressor), HP/

C_3 - propane rate (refrigeration), Bbl/d / m3/d

C_4 - butane rate (refrigeration), Bbl/d / m3/d

C_5 - pentane rate (refrigeration), Bbl/d / m3/d

CE - compressor efficiency, %

C_3GR - propane to gas ratio (refrigeration), Bbl/

C_4GR - butane to gas ratio (refrigeration), Bbl/

C_5GR - pentane & heavier alkanes to gas ratio (refrigeration), Bbl/

CO_2I - CO2 fraction in input stream (amine), %

CO_2O - CO2 fraction in output stream (amine), %

DCQ - daily contract rate,

DP - ΔP for loss due to liquid column, psia /

Eff - flow efficiency (links) or removal efficiency (separator)

F.E. - flow efficiency, %

Fg - fuel gas, %

Gi - gas gravity of stream at input, dimensionless

Go - gas gravity of stream at output, dimensionless

H_2SI - H_2S fraction in input stream (amine), %

H_2SO - H_2S fraction in output stream (amine), %

HL - hydrostatic loss, psi /

ID - internal diameter, in / mm

k - roughness, in / mm

len or Length - link length, mi /

NGL - natural gas liquid rate,

NGLGR - natural gas liquids to gas ratio,

Pm - measured pressure,

Pd - delivery pressure,

Pf- sandface pressure,

P_i - inlet pressure, psia /

P_o - outlet pressure, psia /

PL- pressure loss or line pressure,

P_R - reservoir pressure, psia /

Psuc - suction pressure,

Ptf- wellhead pressure,

Pts- static wellhead pressure,

qf- fuel gas consumption,

qg- gas rate,

qgi- inlet gas rate,

qgo- outlet gas rate,

ql- liquid rate,

qli- input liquid rate,

qlo- output liquid rate,

S.L. - Surface Loss, %

util - Utilized horsepower (compressor),

vg- gas velocity,

vge- erosional velocity,

W.I. - Working Interest, %

Glossary

AOF - Absolute Open Flow

API - American Petroleum Institute

Capital costs - one-time costs that account for costs associated with adding new wells, facilities or pipelines to the gathering system. Examples of capital costs might be the finding, drilling and completion costs for a well, the design, procurement and installation of a compressor, or the build-out of a new pipeline.

Converge - the residual error for pressure and rate from one iteration to the next is below the tolerance set in the software.

Discount rate - the rate by which future revenues, costs, and cash flows are discounted back to a present value.

Entity – any facility that can be defined at a certain location. This can be a node, delivery point, well, separator, and so on.

EOT - End Of Tubing

EUR - Estimate Ultimate Recovery

Fixed rate well - A fixed fluid rate is defined; the well flows at the rate specified independent of the wellhead pressure. A fixed rate well does not have a primary fluid so there is one well type for oil, gas and water wells.

Gathering system - the infrastructure by which hydrocarbons are transported from wells to the point of sale. This system may consist of pipes, compressors, separation units (separators, amine plants and refrigeration units), and so on. A gathering system must be connected to a delivery point (point of sales) for Piper to run calculations.

Inflation rate- the rate by which future fixed and variable monthly costs will be incremented into the future.

Injection system - the infrastructure by which fluids are injected into wells. This system may consist of pipes, compressors, separation units (separators, amine plants and refrigeration units), and so on. An injection system must be connected to a delivery point (point of sales) for Piper to run calculations.

Labor costs - costs associated with installation and tie-in of the pipeline. Labor costs are defined on a $/mile ($/km) basis.

Link – the pipeline connection between any two points.

Material costs - costs directly associated with procuring the length and diameter of pipe desired.

Model - the gathering or injection system created in Piper.

Monthly fixed operating costs - a fixed, system-level cost (i.e.,. a cost that can not be associated with any particular facility) applied every month, for example, field operator, pigging programs, or land leasing costs.

Monthly operating costs - fixed costs that occur on a monthly basis, for example, compressor maintenance, replacement parts, and salaries.

mpp - mid point of perforation

OGIP - Original Gas In Place

OOIP - Original Oil In Place

Profile well - a fixed deliverability well that provides a profile of fluid rates that change by time interval. Profile wells are not affected by changes in wellhead pressure.

PVT - Pressure, Volume, Temperature

RTA - Rate Transient Analysis

Specific gravity -the process of taking a sample fluid and finding its density at a certain temperature and pressure then comparing that to the density of a reference fluid at the same temperature and pressure. For oil and gas, the temperature and pressure combination is usually at standard conditions.

> **Gas gravity** -Pure air is the reference fluid. Since most natural gas is less dense than air, the ratio is in the range of 0.55 < SG < 1
>
> **Oil (API) gravity** - Pure water is the reference fluid. Oil is usually less dense than water.
>
> **Water specific gravity** - Pure water is the reference fluid. The default is 1.0000. However, a lot of reservoir water is brackish, so it can be more dense, approximately 1.01.

Variable operating costs - costs that depend on the amount of gas being produced., for example, H2S management, or liquid disposal costs.

Well – a defined location where rate enters the gathering system. It is intended to represent the location of an actual well, and can be represented with either a simple or complex deliverability model.

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