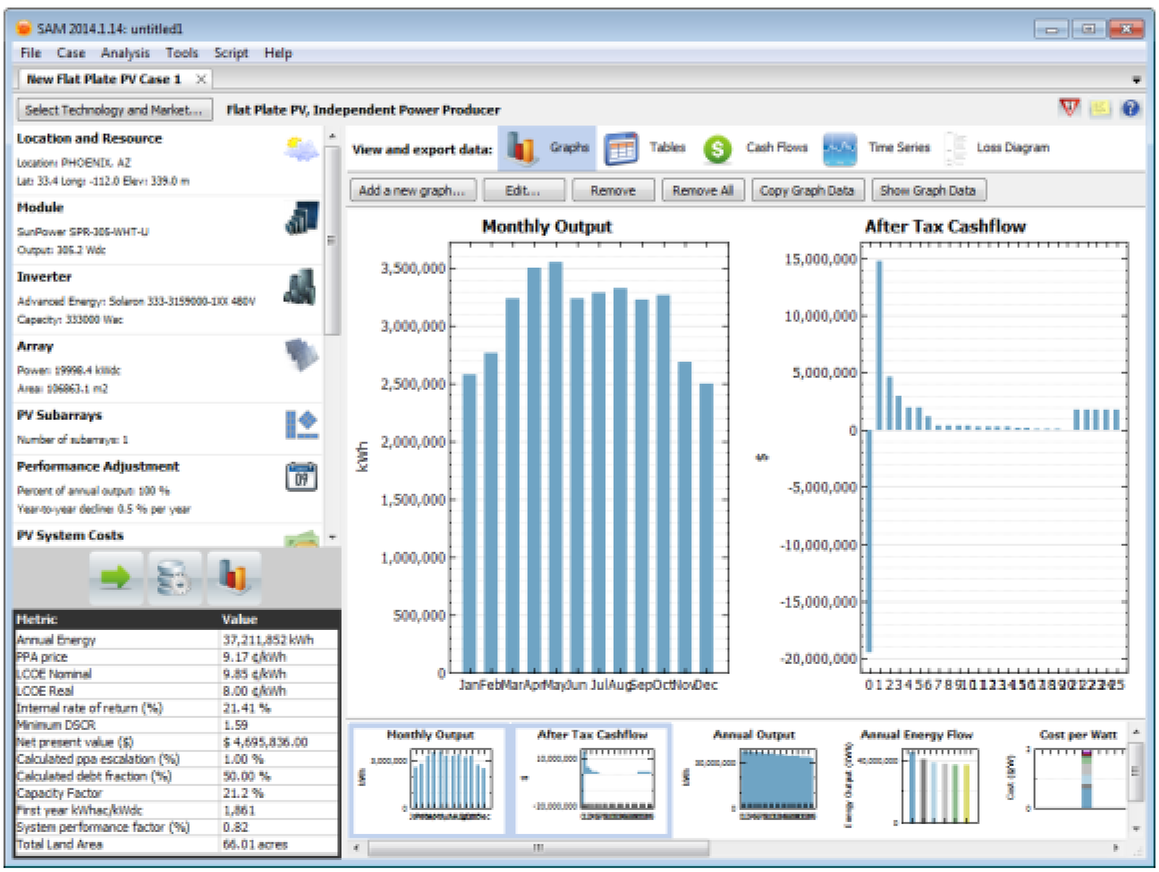
System Advisor Model (SAM)

This document is a copy of SAM's Help system.

To see the Help system in SAM, click Help Contents on the Help menu, or press the F1 key (command-? in Mac OS) from any page in SAM.



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1 Introduction

The System Advisor Model (SAM) is a performance and financial model for renewable energy power systems and projects.

- For a general description of SAM, see About SAM.
- For information about getting help using SAM, see User Support.
- For instructions on getting the latest version or updating your version of SAM, see Keep SAM Up to Date.

1.1 About SAM

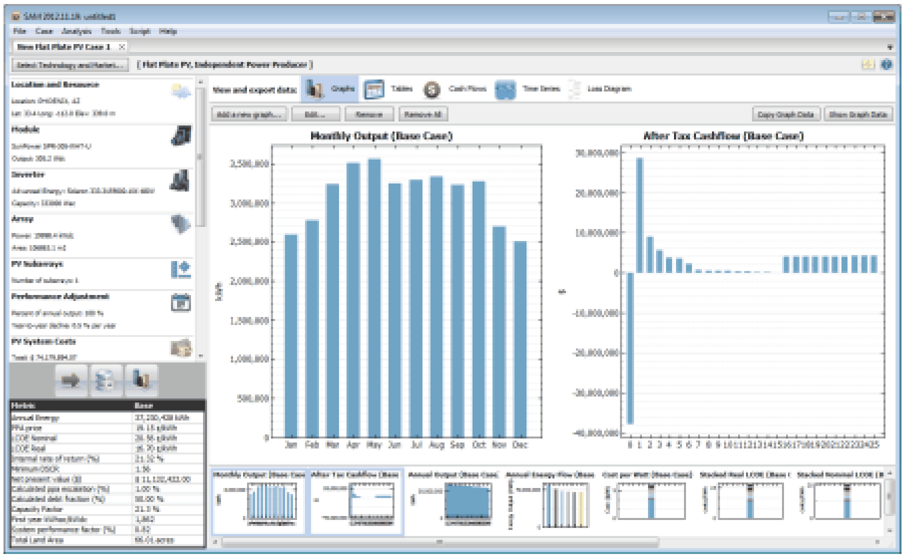
The System Advisor Model (SAM) is a performance and financial model designed to facilitate decision making for people involved in the renewable energy industry:

- Project managers and engineers
- Policy analysts
- Technology developers
- Researchers

SAM makes performance predictions and cost of energy estimates for grid-connected power projects based on installation and operating costs and system design parameters that you specify as inputs to the model.

Projects can be either on the customer side of the utility meter, buying and selling electricity at retail rates, or on the utility side of the meter, selling electricity at a price negotiated through a power purchase agreement (PPA).

The following image shows SAM's main window showing monthly electricity generation and the annual cash flow for a photovoltaic system.



The first step in creating a SAM file is to choose a technology and financing option for your project. SAM automatically populates input variables with a set of default values for the type of project. It is your responsibility as an analyst to review and modify all of the input data as appropriate for each analysis.

Next, you provide information about a project's location, the type of equipment in the system, the cost of installing and operating the system, and financial and incentives assumptions.

SAM Models and Databases

SAM represents the cost and performance of renewable energy projects using computer models developed at NREL, Sandia National Laboratories, the University of Wisconsin, and other organizations. Each performance model represents a part of the system, and each financial model represents a project's financial structure. The models require input data to describe the performance characteristics of physical equipment in the system and project costs. SAM's user interface makes it possible for people with no experience developing computer models to build a model of a renewable energy project, and to make cost and performance projections based on model results.

SAM requires a resource data file describing the renewable energy resource and weather conditions a the project location. Depending on the kind of system you are modeling, you either choose a resource data file from a list, download one from the internet, or create the file using your own data.

SAM can automatically download data from the following online databases:

- DSIRE for U.S. incentives.
- OpenEI Utilities Gateway for retail electricity rate structures for U.S. utilities
- NREL Solar Prospector for solar resource data and ambient weather conditions.
- NREL Wind Integration Datasets for wind resource data.
- NREL Biofuels Atlas and DOE Billion Ton Update for biomass resource data.
- NREL Geothermal Resource database for temperature and depth data.

SAM includes several databases of performance data and coefficients for system components such as photovoltaic modules and inverters, parabolic trough receivers and collectors, wind turbines, or biopower combustion systems. For those components, you simply choose an option from a list. For U.S. locations, SAM can also automatically download data describing incentives and retail electricity rate structures from online databases.

For the remaining input variables, you either use the default value or change its value. Some examples of input variables are:

- Installation costs including equipment purchases, labor, engineering and other project costs, land costs, and operation and maintenance costs.
- Numbers of modules and inverters, tracking type, derating factors for photovoltaic systems.
- Collector and receiver type, solar multiple, storage capacity, power block capacity for parabolic trough systems.
- Analysis period, real discount rate, inflation rate, tax rates, internal rate of return target or power purchase price for utility financing models.
- Building load and time-of-use retail rates for commercial and residential financing models.
- Tax and cash incentive amounts and rates.

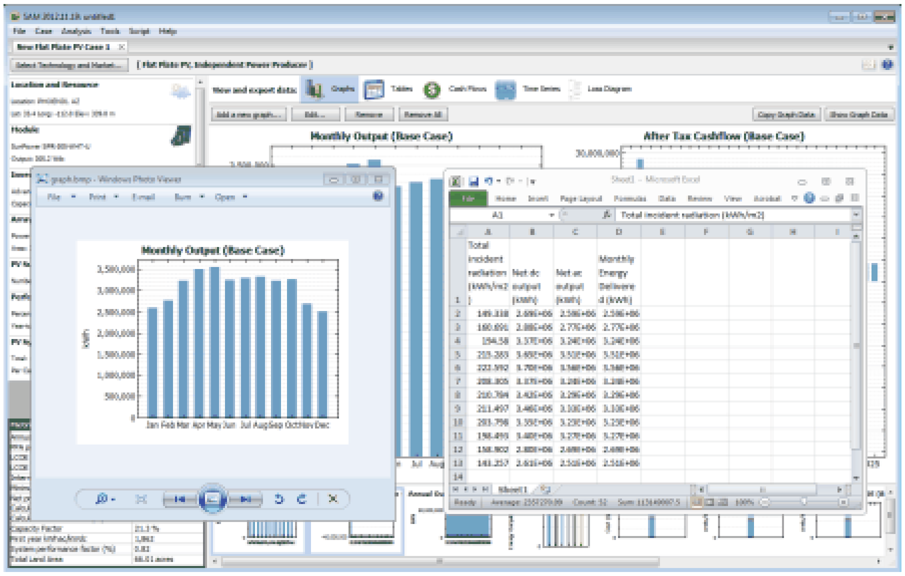
Once you are satisfied with the input variable values, you run simulations, and then examine results. A typical analysis involves running simulations, examining results, revising inputs, and repeating that process until you understand and have confidence in the results.

Results: Tables, Graphs, and Reports

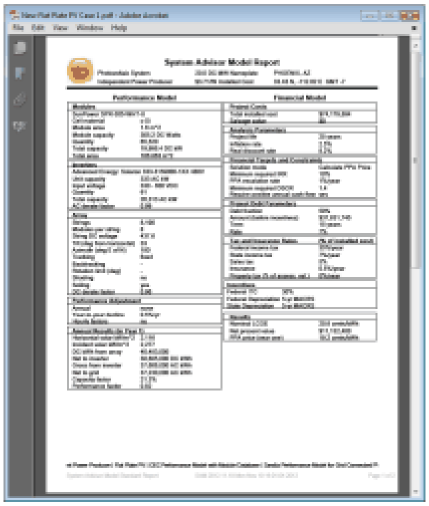
SAM displays modeling results in tables and graphs, ranging from the metrics table displaying levelized cost of energy, first year annual production, and other single-value metrics, to the detailed annual cash flow and hourly performance data that can be viewed in tabular or graphical form.

A built-in graphing tool displays a set of default graphs and allows for creation of custom graphs. All graphs and tables can be exported in various formats for inclusion in reports and presentations, and also for further analysis with spreadsheet or other software.

The Results page displays graphs of results that you can easily export to your documents:



SAM's report generator allows you to create custom reports to include SAM results in your project proposals and other documents:



Performance Model

SAM's performance model makes hour-by-hour calculations of a power system's electric output, generating a set of 8,760 hourly values that represent the system's electricity production over a single year. You can explore the system's performance characteristics in detail by viewing tables and graphs of the hourly and monthly performance data, or use performance metrics such as the system's total annual output and capacity factor for more general performance evaluations.

The Time Series graph on the Results page showing hourly electricity generation for a 100 MW parabolic trough system with 6 hours of storage in Blythe, California:

The current version of the SAM includes performance models for the following technologies:

- Photovoltaic systems (flat-plate and concentrating)
- Parabolic trough concentrating solar power

- Power tower concentrating solar power (molten salt and direct steam)
- Linear Fresnel concentrating solar power
- Dish-Stirling concentrating solar power
- Conventional fossil-fuel thermal
- Solar water heating for residential or commercial buildings
- Large and small wind power
- Geothermal power and geothermal co-production
- Biomass power

Financial Model

SAM's financial model calculates financial metrics for various kinds of power projects based on a project's cash flows over an analysis period that you specify. The financial model uses the system's electrical output calculated by the performance model to calculate the series of annual cash flows.

SAM includes financial models for the following kinds of projects:

- Residential (retail electricity rates)
- Commercial (retail rates or power purchase agreement)
- Utility-scale (power purchase agreement):
  - Single owner
  - Leveraged partnership flip
  - All equity partnership flip
  - Sale leaseback

Residential and Commercial Projects

Residential and commercial projects are financed through either a loan or cash payment, and recover investment costs by selling electricity through either a net metering or time-of-use pricing agreement. For these projects, SAM reports the following financial metrics:

- Levelized cost of energy
- Electricity cost with and without renewable energy system
- After-tax net present value
- Payback Period

Power Purchase Agreement (PPA) Projects

Utility and commercial PPA projects are assumed to sell electricity through a power purchase agreement at a fixed price with optional annual escalation and time-of-delivery (TOD) factors. For these projects, SAM calculates:

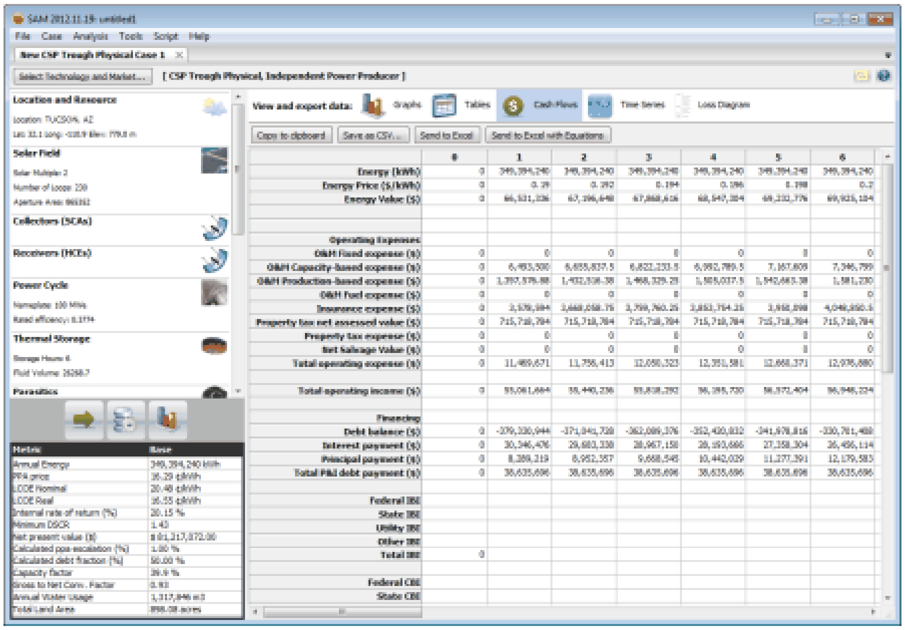
- Levelized cost of energy
- PPA price (electricity sales price)
- Internal rate of return
- Net present value
- Debt fraction or debt service coverage ratio

SAM can either calculate the internal rate of return based on a power price you specify, or calculate the power price based on the rate of return you specify.

Levelized Cost of Energy and Cash Flow

SAM calculates the levelized cost of energy (LCOE) after-tax cash flows for projects using retail electricity rates, and from the revenue cash flow for projects selling electricity under a power purchase agreement.

The following image shows several rows of the cash flow table for a utility-scale project:



The project annual cash flows include:

- Value of electricity sales (or savings) and incentive payments
- Installation costs
- Operating, maintenance, and replacement costs
- Loan principal and interest payments
- Tax benefits and liabilities (accounting for any tax credits for which the project is eligible)
- Incentive payments
- Project and partner's internal rate of return requirements (for PPA projects)

Incentives

The financial model can account for a wide range of incentive payments and tax credits:

- Investment based incentives (IBI)
- Capacity-based incentives (CBI)
- Production-based incentives (PBI)
- Investment tax credits (ITC)
- Production tax credits (PTC)
- Depreciation (MACRS, Straight-line, custom, bonus, etc.)

Analysis Options

In addition to simulating a system's performance over a single year and calculating a project cash flow over a multi-year period, SAM's analysis options make it possible to conduct studies involving multiple simulations, linking SAM inputs to a Microsoft Excel workbook, and working with custom simulation modules.

The following options are for analyses that investigate impacts of variations and uncertainty in assumptions about weather, performance, cost, and financial parameters on model results:

- Parametric Analysis: Assign multiple values to input variables to create graphs and tables showing the value of output metrics for each value of the input variable. Useful for optimization and exploring relationships between input variables and results.
- Sensitivity Analysis: Create tornado graphs by specifying a range of values for input variables as a percentage.
- Statistical: Create histograms showing the sensitivity of output metrics to variations in input values.
- P50/P90: For locations with weather data available for many years, calculate the probability that the system's total annual output will exceed a certain value.

For files with multiple cases, the Multiple Subsystems option allows you to model a project that combines systems from the cases, assuming that the system's total electrical output is the sum of the output of the subsystems modeled in each case, and applies the financing model from one case to this total output.

SAM also makes it possible to work with external models developed in Excel or the TRNSYS simulation platform:

- Excel Exchange: Use Excel to calculate the value of input variables, and automatically pass values of input variables between SAM and Excel.
- Exchange Variables: Create your own input variables for use with Excel Exchange or a custom TRNSYS deck.
- Simulator Options: Change the simulation time step, or run SAM with your own simulation modules developed in the TRNSYS modeling platform.

Finally, SAM's scripting language SamUL allows you to write your own programs within the SAM user interface to control simulations, change values of input variables, and write data to text files.

Software Development History and Users

SAM, originally called the "Solar Advisor Model" was developed by the National Renewable Energy Laboratory in collaboration with Sandia National Laboratories in 2005, and at first used internally by the U.S. Department of Energy's Solar Energy Technologies Program for systems-based analysis of solar technology improvement opportunities within the program. The first public version was released in August 2007 as Version 1, making it possible for solar energy professionals to analyze photovoltaic systems and concentrating solar power parabolic trough systems in the same modeling platform using consistent financial assumptions. Since 2007, two new versions have been released each year, adding new technologies and financing options. In 2010, the name changed to "System Advisor Model" to reflect the addition of non-solar technologies.

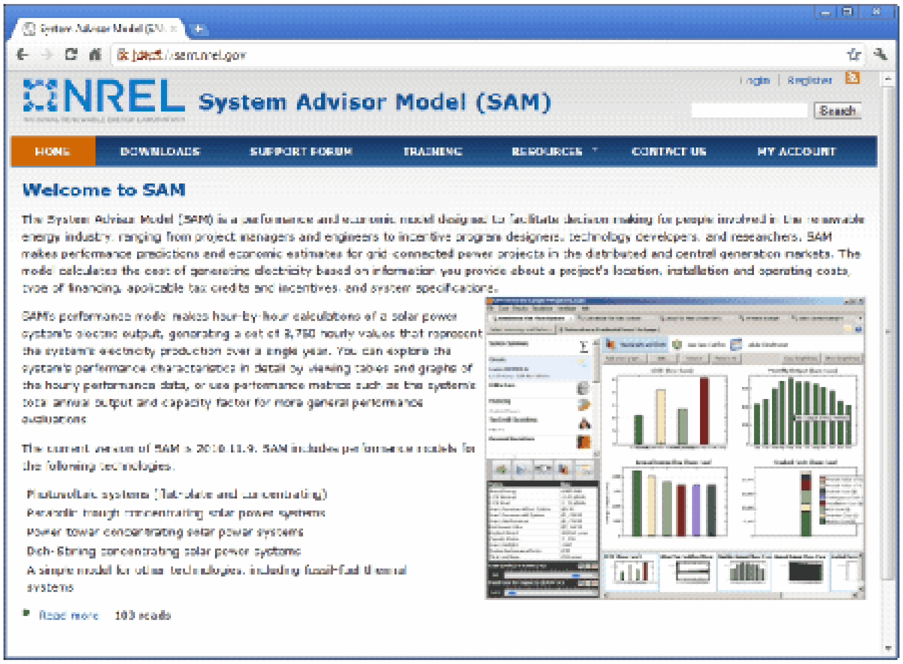
The DOE, NREL, and Sandia continue to use the model for program planning and grant programs. Since the first public release, over 35,000 people representing manufacturers, project developers, academic researchers, and policy makers have downloaded the software. Manufacturers are using the model to evaluate the impact of efficiency improvements or cost reductions in their products on the cost of energy from installed systems. Project developers use SAM to evaluate different system configurations to maximize earnings from electricity sales. Policy makers and designers use the model to experiment with different incentive structures.

Downloading SAM and User Support

SAM runs on both Windows and OS X. It requires about 500 MB of storage space on your computer.

SAM is available for free download at http://sam.nrel.gov. To download the software, you must register for an account on the website. After registering, you will receive an email with your account information.

SAM's website includes software descriptions, links to publications about SAM and other resources:

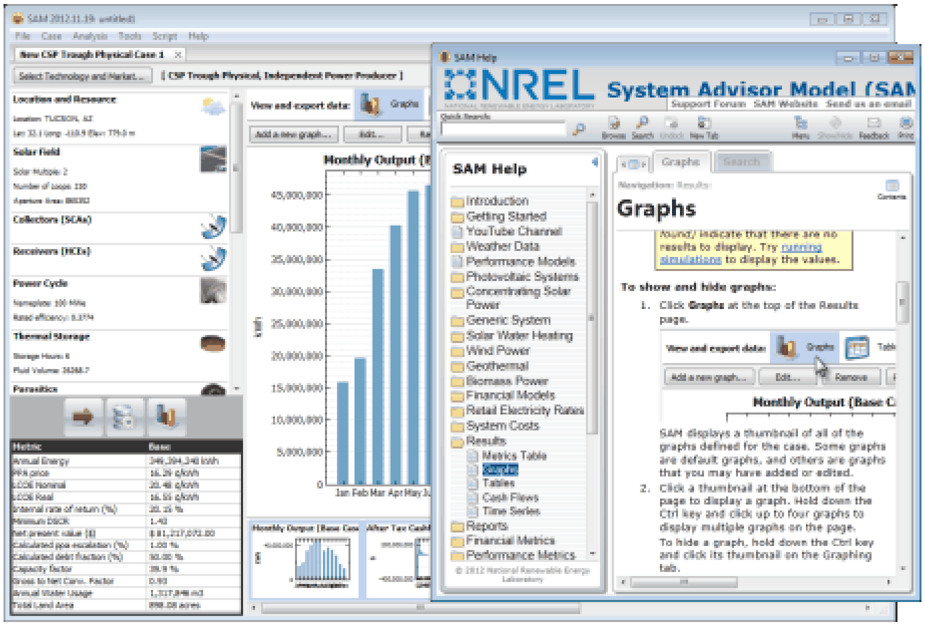


The following resources are available for learning to use SAM and for getting help with your analyses:

- The built-in Help system (also available on the website)
- User support forum: https://sam.nrel.gov/forums/support-forum
- Demonstration videos on the SAM website: https://sam.nrel.gov/content/resources-learning-sam
- Periodic webinars: https://sam.nrel.gov/content/resources-learning-sam

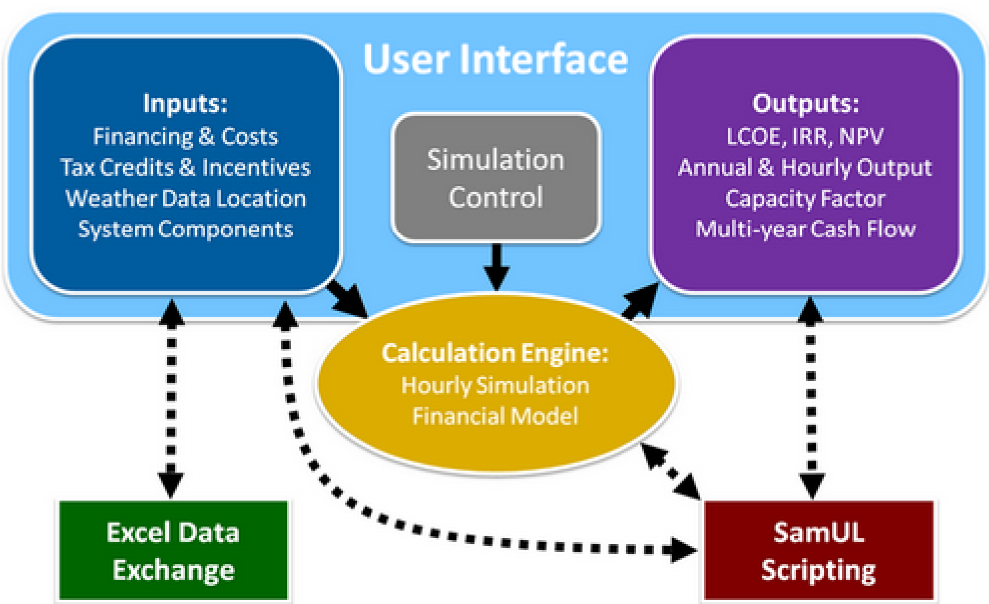
You can contact the SAM support team by emailing sam.support@nrel.gov.

SAM's help system includes detailed descriptions of the user interface, modeling options, and results:



Model Structure

SAM consists of a user interface, calculation engine, and programming interface. The user interface is the part of SAM that you see, and provides access to input variables and simulation controls, and displays tables and graphs of results. SAM's calculation engine performs a time-step-by-time-step simulation of a power system's performance, and a set of annual financial calculations to generate a project cash flow and financial metrics. The programming interface allows external programs to interact with SAM.



The user interface performs three basic functions:

- Provide access to input variables, which are organized into input pages. The input variables describe the physical characteristics of a system, and the cost and financial assumptions for a project.

- Allow you to control how SAM runs simulations. You can run a basic simulation, or more advanced simulations for optimization and sensitivity studies.
- Provide access to output variables in tables and graphs on the Results page, and in files that you can access in a spreadsheet program or graphical data viewer.

SAM's scripting language SamUL allows you to automate certain tasks. If you have some experience writing computer programs, you can easily learn to write SamUL scripts to set the values of input variables by reading them from a text file or based on calculations in the script, run simulations, and write values of results to a text file. You can also use SamUL to automatically run a series of simulations using different weather files.

Excel Exchange allows you to use Microsoft Excel to calculate values of input variables. With Excel Exchange, each time you run simulations, SAM opens a spreadsheet and, depending on how you've configured Excel Exchange, writes values from SAM input pages to the spreadsheet, and reads values from the spreadsheet to use in simulations. This makes it possible to use spreadsheet formulas to calculate values of SAM input variables.

Calculation Engine

Each renewable energy technology in SAM has a corresponding performance model that performs calculations specific to the technology. Similarly, each financing option in SAM is also associated with a particular financial model with its own set of inputs and outputs. The financial models are as independent as possible from the performance models to allow for consistency in financial calculations across the different technologies.

A performance simulation consists of a series of many calculations to emulate the performance of the system over a one year period in time steps of one hour for most simulations, and shorter time steps for some technologies.

A typical simulation run consists of the following steps:

1. After starting SAM, you select a combination of technology and financing options for a case in the user interface.
2. Behind the scenes, SAM chooses the proper set of simulation and financial models.
3. You specify values of input variables in the user interface. Each variable has a default value, so it is not necessary to specify a value for every variable.
4. When you click the Run button, SAM runs the simulation and financial models. For advanced analyses, you can configure simulations for optimization or sensitivity analyses before running simulations.
5. SAM displays graphs and tables of results in the user interface's Results page.

1.2 Component Models and Databases

This topic lists all of SAM's performance models and describes the component-level models and databases SAM uses.

System Performance Models

The system models represent a complete renewable energy system and were developed by NREL using algorithms from partners listed below.

Model Name	Partner (if any)
Flat Plate PV	Component models from Sandia National Laboratories and the University of Wisconsin
High-X Concentrating PV	
PVWatts System Model	
Parabolic Trough Physical Model	University of Wisconsin
Parabolic Trough Empirical Model	University of Wisconsin
Molten Salt Power Tower	University of Wisconsin
Direct Steam Power Tower	University of Wisconsin
Linear Fresnel	University of Wisconsin
Dish Stirling	University of Wisconsin
Generic Solar System	
Generic System	
Solar Water Heating	
Wind Power	University of Wisconsin
Geothermal Power	Princeton Energy Resources International
Geothermal Co-production	
Biomass Power	

Component Performance Models

The Flat Plate PV and Wind Power model include options for choosing a component performance model to represent part of the system.

Model Name	Component	Developer
Simple Efficiency Module Model	Photovoltaic module	NREL
CEC Performance Model with Module Data base	Photovoltaic module	University of Wisconsin
CEC Performance Model with User Entered Specifications	Photovoltaic module	Adapted by NREL
Sandia PV Array Performance Model with Module Database	Photovoltaic module	Sandia National Laboratories
Single Point Efficiency Inverter	Inverter	NREL
Sandia Performance Model for Grid Connected PV Inverters	Inverter	Sandia National Laboratories
Wind Turbine Design Model	Wind Turbine	NREL
Wind Power Curve Model	Wind Turbine	NREL

Component Parameter Databases

Some of the component models use a library of input parameters to represent the performance characteristics of the component. The libraries listed below are owned by organizations other than NREL.

Library Name	Component	Owner
CEC Modules	PV module	California Energy Commission
Sandia Inverters	Inverter	Sandia National Laboratories

Library Name	Component	Owner
Sandia Modules	PV module	Sandia National Laboratories

Online Financial Model Data

SAM can automatically download data from the following online databases to populate values on its financial model input pages.

Database Name	Type of Data	Database Manager
OpenEI Utilities Gateway	Retail electricity prices and rate structures	NREL and Illinois State University
DSIRE	Incentives	North Carolina Solar Center and Interstate Renewable Energy Council

Online Renewable Resource and Weather Data Sources

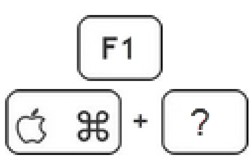
SAM can automatically download renewable energy resource and weather data from the following online databases.

Database Name	Type of Resource Data	Database Manager
Solar Prospector	Solar and Meteorological	NREL
Wind Integration Datasets	Wind and Meteorological	NREL with 3Tier and AWS Truepower
Geothermal Resource	Ground temperature and depth	Southern Methodist University
NREL Biofuels Atlas	Agricultural Residues	NREL
Billion Ton Update	Dedicated energy crops	Department of Energy

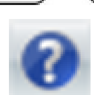
SAM also comes with a complete set of TMY2 files (1961-1990) from the National Solar Radiation Database (NSRDB). It can read NSRDB TMY3 files, and EPW files developed for the Department of Energy's EnergyPlus building simulation model.

1.3 User Support

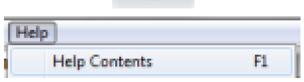
For information about any page in the software, do one of the following:



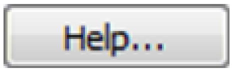
Press the F1 key in Windows or Command-? in Mac OS.



Click the help button at the top right corner of each input page.



Click **Help Contents** from the Help menu.



In secondary windows, click the Help button for information about the window.

For additional help, try:

For general information about the model, including a discussion of project costs, references to related publications and a list of frequently asked questions, and other information visit the SAM website: http://sam.nrel.gov/.

For user support, post a question on the SAM forum at https://sam.nrel.gov/forums/support-forum.

To send an email to the SAM team, contact us at sam.support@nrel.gov.

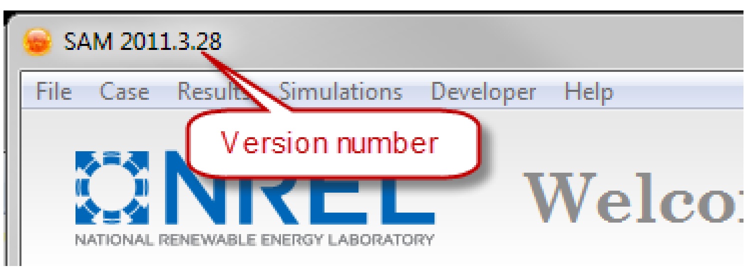
1.4 Keep SAM Up to Date

SAM Versions

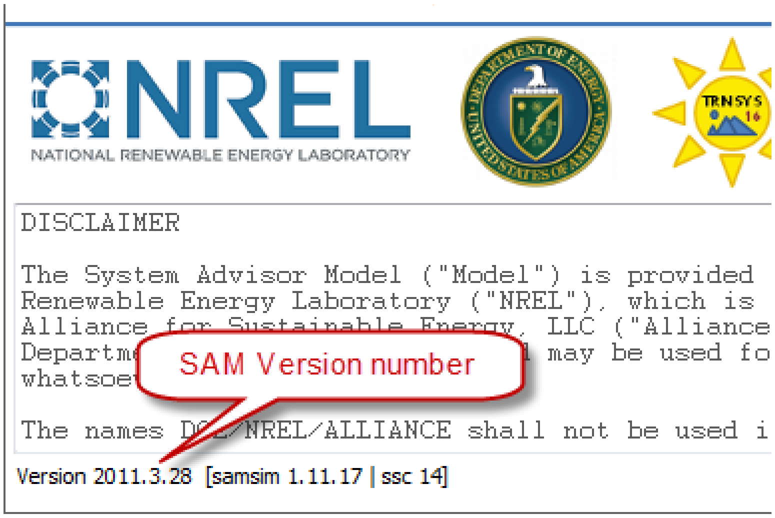
The SAM team releases new versions of SAM periodically. To find out if your version of SAM is the latest version, check the SAM website at http://sam.nrel.gov/.

SAM's Welcome page also displays news from the SAM team, including announcements of new versions.

SAM displays the version number in the title bar of the Main window:



You can also find the SAM version number along with version numbers of other components of the software by clicking **About** on the **Help** menu:



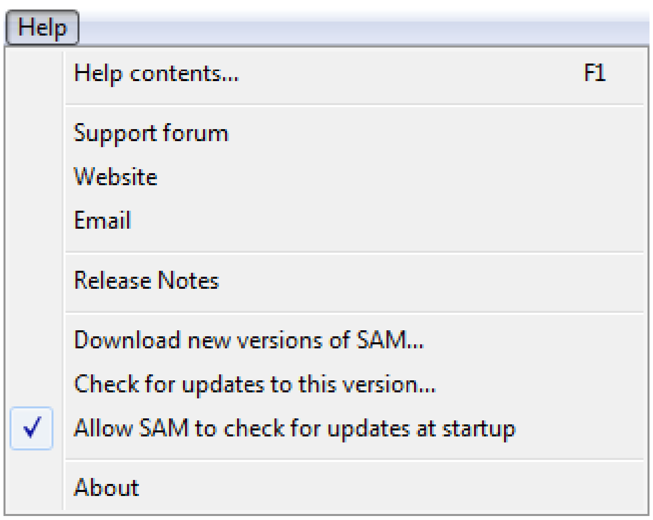
Checking for Updates

Updates may be available before a new release is available to address minor issues with the software.

By default, SAM checks the SAM website for updates each time you start the software. You can disable this feature by clearing the checkmark on the Help menu next to **Allow SAM to check for updates at startup**.

To check for updates:

- On the Help menu, click **Check for updates to this version**.



2 Getting Started

The Getting Started topics introduce you to SAM:

- Start a Project describes the steps for creating a SAM file.
- Welcome Page describes the Welcome page that appears when you first start SAM.
- Main Window describes SAM's main window that appears when you open a SAM file, where you access input pages and results.
- Input Pages describes the general layout of SAM's input pages where you specify the value of input variables.
- Run Simulations explains how to run simulations.
- Results Page describes the general layout of the page displaying results.
- Export Data and Graphs explains how to export data and images of graphs from SAM for use in spreadsheets, reports, presentations, and other documents.
- Manage Cases explains how to work with cases in a SAM file.
- Menus describes SAM's menus.
- Notes explains how to use notes to store text messages in SAM.
- File Formats describes the types of files used with SAM.

2.1 Start a Project

The following procedure describes the basic steps to set up and run a simulation of a project.

See also:

- Financing Overview
- Technology Options
- Getting Started with PV

A. Create a file

When you start SAM, it displays the Welcome page with several options for creating or opening a file.

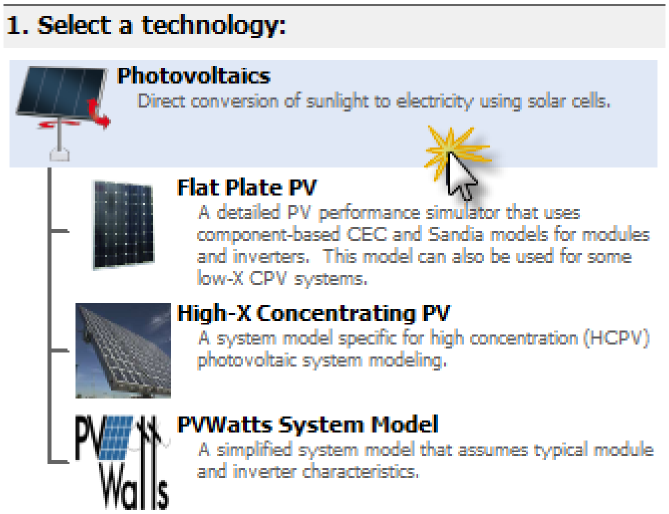
To create a new file, under **Enter a new project name to begin**, type a name for your project and click **Create a new file**.

SAM displays the technology and financing options. You must choose both a technology to model and a financing option for the project.

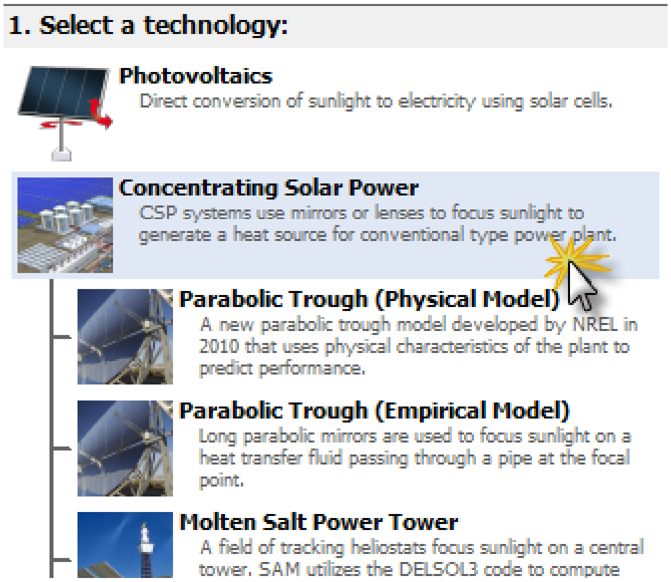
B. Choose a technology

The technology option you choose determines the performance model that SAM uses for simulations. SAM offers performance models for photovoltaic, concentrating solar power, solar water heating, wind, geothermal, and biomass power systems. The generic system model allows you to represent a system using only a nameplate capacity and capacity factor, or an hourly or subhourly generation profile from another performance model or data source.

For photovoltaic systems, click **Photovoltaics** to expand the list of options. If you want to choose a specific module and inverter from a list, choose **Flat Plate PV**. If you want to model the entire system using a single derate factor, choose **PVWatts System Model**.



For parabolic trough systems, click **Concentrating Solar Power** to expand the list of options and then choose **Parabolic Trough (Physical Model)**. If you are modeling a system with a configuration similar to the SEGS plants choose **Parabolic Trough (Empirical Model)**.

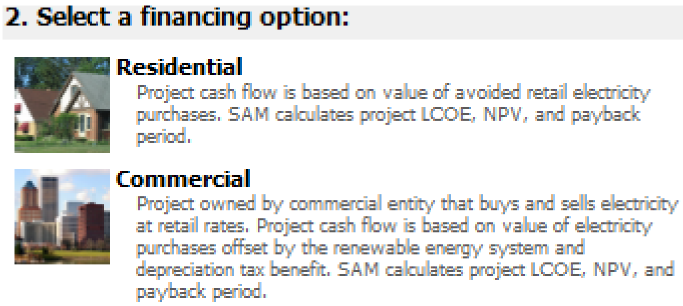


For other technologies, choose the appropriate option. See Technology Options for descriptions.

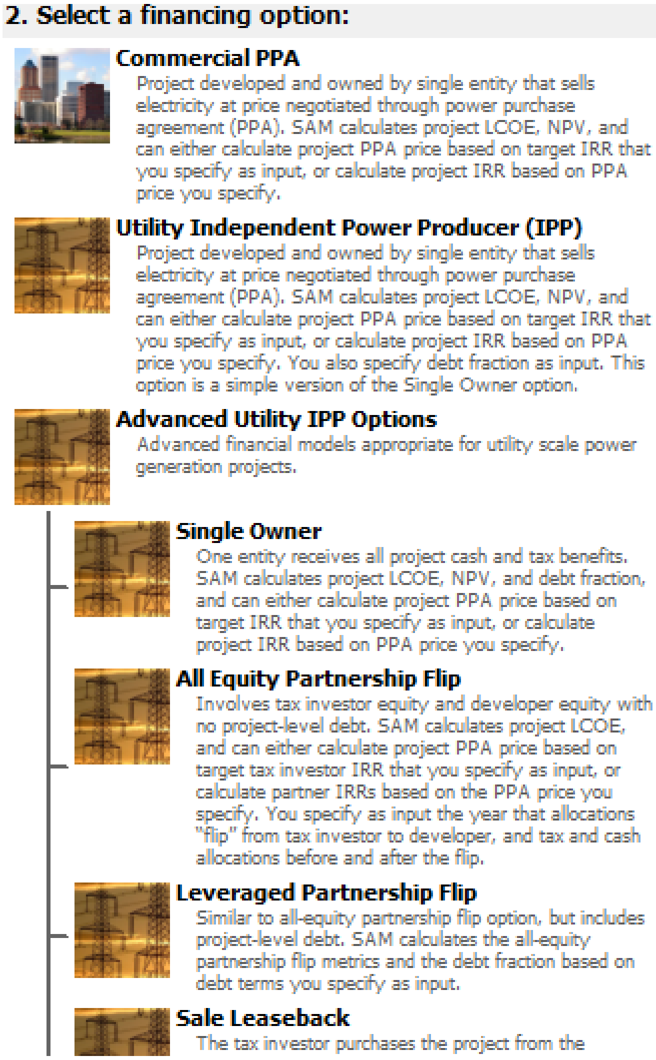
C. Choose a financing option

When you choose a technology option, SAM displays financing options available for the technology under the **Select a financing option** heading. For a description of the financing options, see Financing Overview.

For projects on the customer side of the electric power meter that buy and sell electricity at retail rates, choose either **Residential** or **Commercial**.



For power generation projects that sell power at a price negotiated through a power purchase agreement, choose either **Commercial PPA**, **Utility Independent Power Producer (IPP)**, or one of the **Advanced Utility IPP** options.



When you choose a financing option, and click **OK**, SAM creates a new file and populates all of the input variables with values from the default values database.

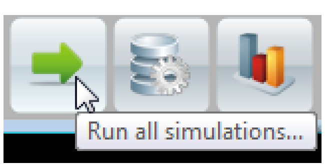
D. Review inputs

After creating your file, open each input page and review the default assumptions.

See Input Pages for details.

E. Run simulations

To run simulations, click the Run button.



See Run Simulations for details.

F. Review results

When simulations are complete, SAM displays a summary of results in the Metric table.

Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

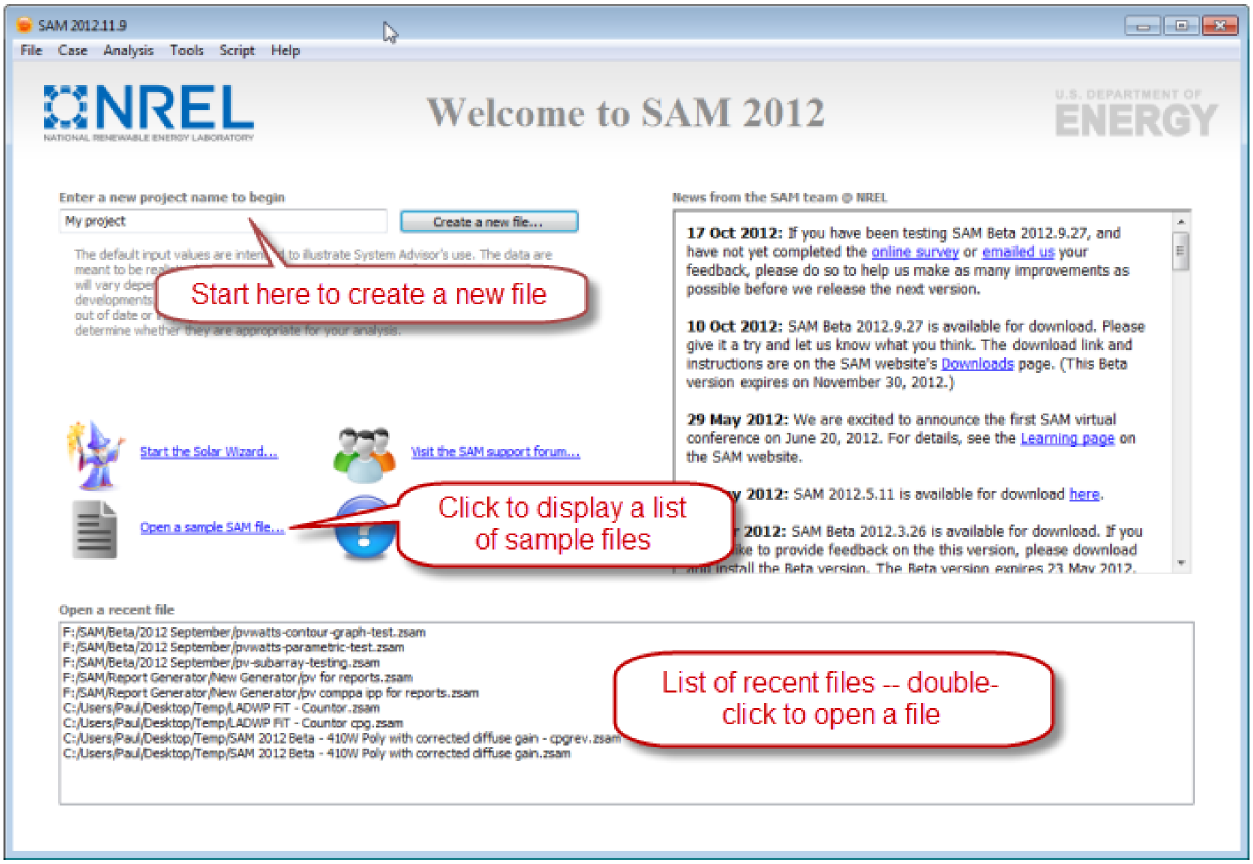
You can display graphs and tables of detailed results data on the Results page.

2.2 Welcome Page

When you start SAM, it displays a Welcome window with several options for starting a project:

- Create a new file to start a project. Type the project name and click **Create a new file** to display the Technology and Market window where you choose a technology and financing option.
- Open a sample file. The sample files illustrate how to model some common types of projects and how to use some of SAM's more advanced modeling techniques.
- Open a recent file. The Recent Files list contains project files that were saved during previous SAM sessions.

Note. To return to the Welcome page after creating a case, click **Close** on the **File** menu.



Solar Wizard

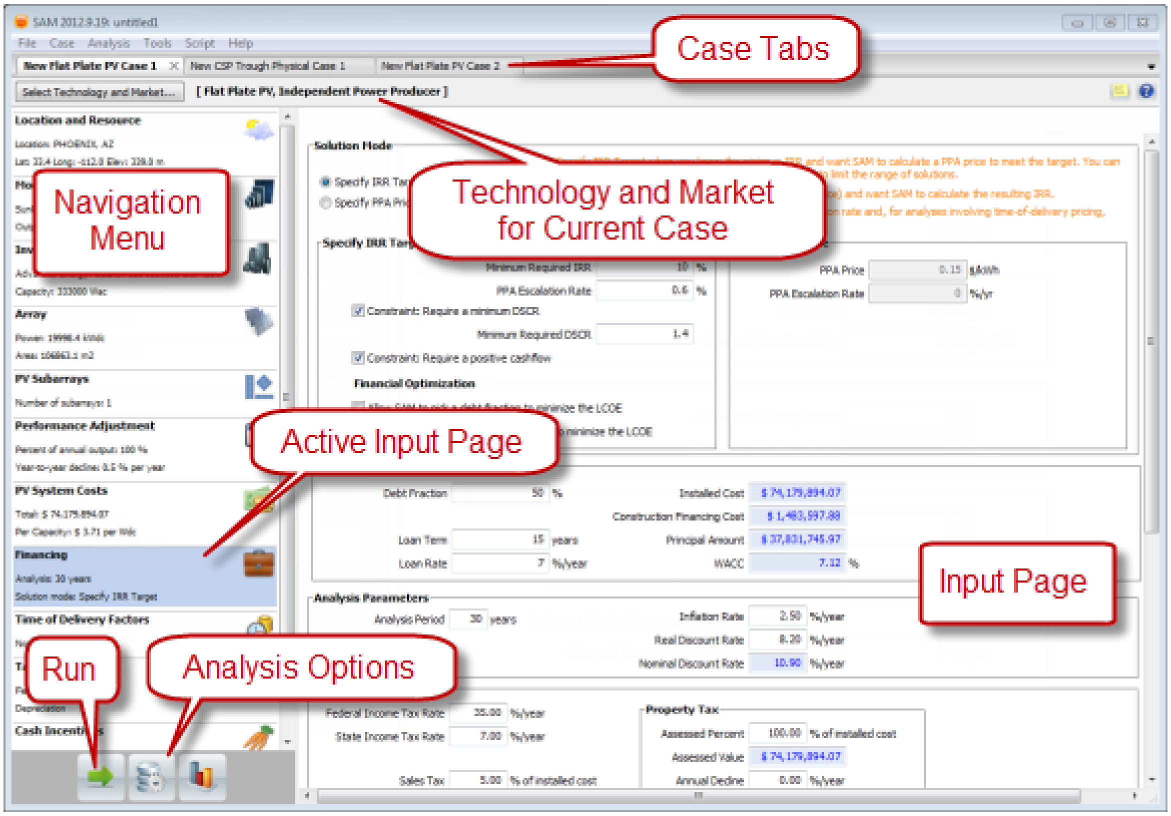
The solar wizard walks you through the steps to create a file for the following combinations of performance and financial model:

- PVWatts, Residential
- PVWatts, Commercial PPA
- PVWatts, Utility Single Owner
- Empirical Trough, Utility Single Owner
- Solar Water Heating, Residential
- Solar Water Heating, Commercial

The Solar Wizard is designed to help you get started using SAM. You can open the SAM file that the wizard creates to explore all of the inputs and results in the file.

2.3 Main Window

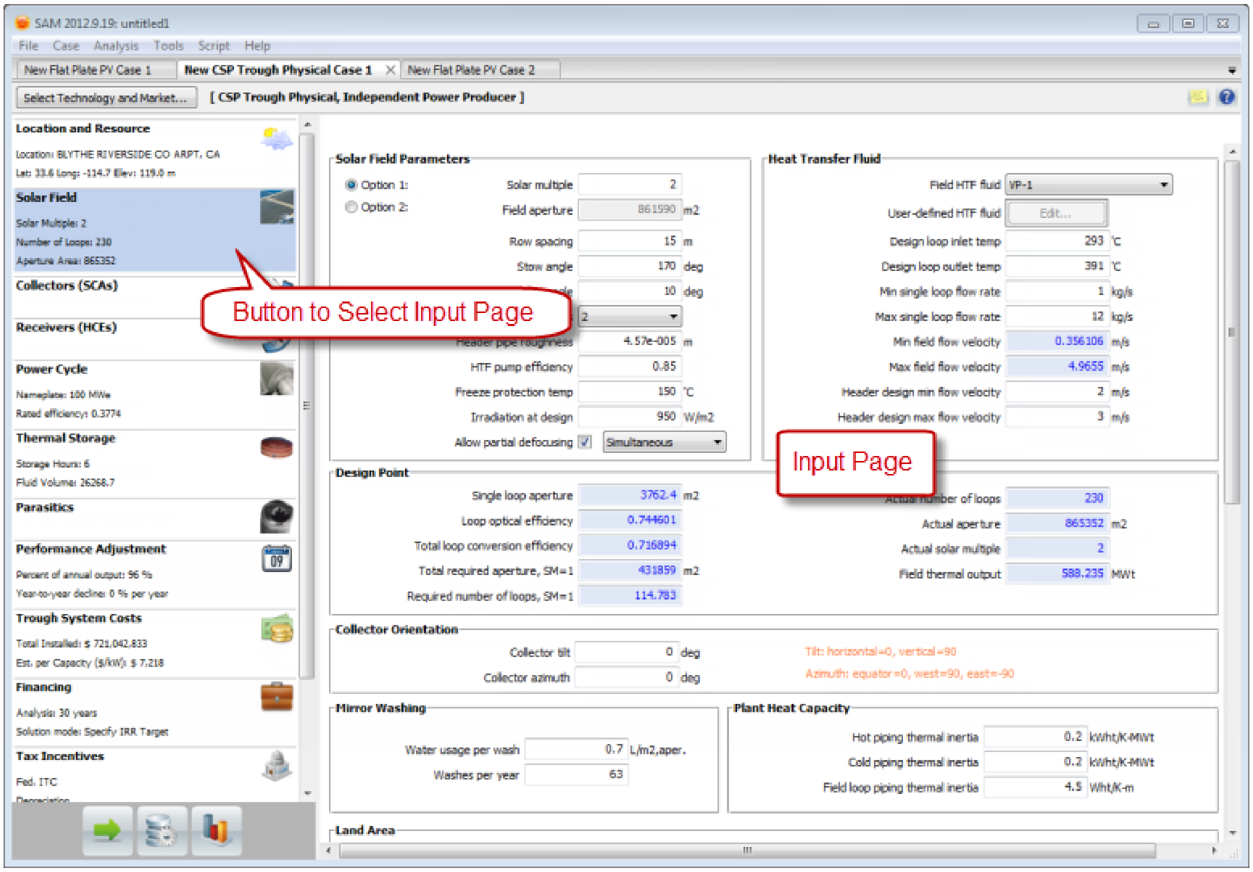
The main window gives you access to the input pages for each of the cases in the project:



- The case tabs display different cases in the project. A project may consist of a single case, or may contain more than one case. Click a tab to display the case. Click the 'x' on a tab to delete the case.
- The navigation menu displays a list of input pages available for the technology and market of the current case. Click an item in the navigation menu to display an input page. The active input page is indicated on the menu in blue. When the menu is too long to fit in the window, use the vertical scroll bar to move through the menu, or resize the Main window to make the entire menu visible. Each item on the navigation menu also displays key data from the input pages. For example, the system costs item in the navigation menu shows the system's total installed cost.

2.4 Input Pages

An input page is where you specify input variable values and options.



SAM's input pages provide access to the input variables and options that define the assumptions of your analysis.

When you start a project by creating a new file SAM populates all of the input variables with default values so that you can get started with your analysis even before you have final values for all of the input variables.

> **Tip.** To see a list of all input variables and their values for a case, on the **Case** menu, click **Show Input Value Summary**.

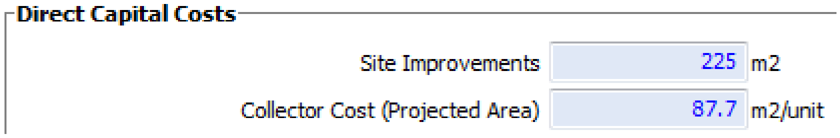
Colors of Input Variables

The text and data box colors on the input pages indicate the kind of information they contain:

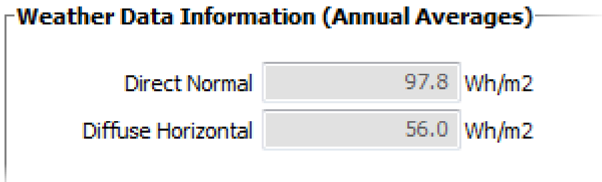
> **Note.** The appearance of text and text boxes depends on whether you are running SAM on Windows or Mac OS. The screenshots below are for Windows.

- White data boxes display input variables that you can modify by typing values in the box:

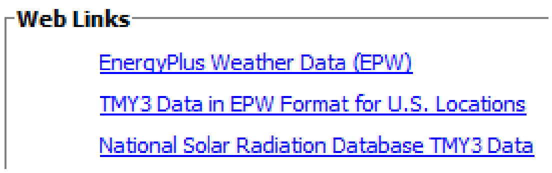
- Blue data boxes are for reference values that SAM either displays from other input pages, or calculates from other input variables. Data in blue cannot be modified. Press the F1 key on your keyboard (Command-? on a Mac) to see the Help topic with descriptions of the equations SAM uses to calculate these values:



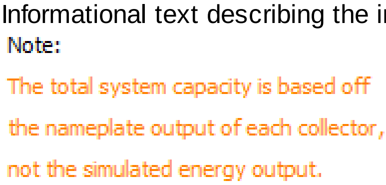
- Gray data boxes show values for your reference. For example, these input variables on the Location and Resource page show annual averages calculated from data stored in the weather file. You cannot modify data in gray:



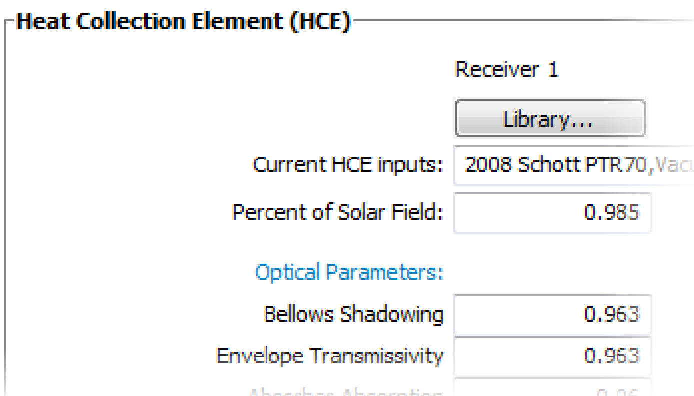
- Blue underlined text indicates links to websites with useful information related to the input page:



- Informational text describing the input variables appears in orange font:

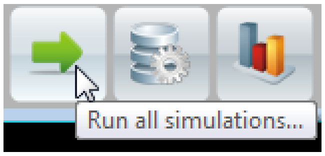


- Library buttons populate input variables with values from a library of stored parameters. Modifying a value on an input page does not change the value stored in the library. See Working with Libraries to learn more about libraries:



2.5 Run Simulations

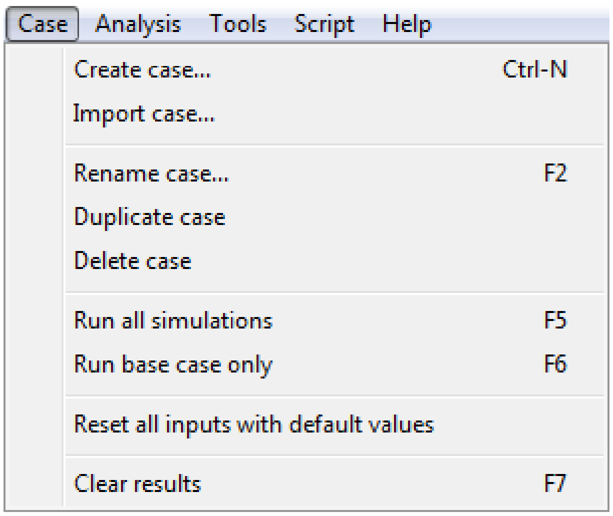
After reviewing and modifying inputs on the input pages, click the Run all Simulations button to run simulations:



SAM runs simulations based on the values of input variables that appear on the input pages and reports those values as "base case" results.

In addition to the base case, SAM runs simulations for any additional simulations you may have set up on the Configure Simulations pages, such as parametric or sensitivity analyses.

You can also run simulations from the Case menu (See Menus for a description of menu commands):



Run All Simulations

Runs all of the simulations configured in the current case. Equivalent to clicking the Run button.

Run Base Case Only

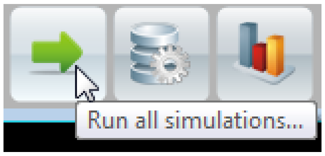
Runs a single simulation based on the input values shown on the input pages, ignoring any parametric, sensitivity, or other configurations requiring multiple simulation runs.

2.6 Results Page

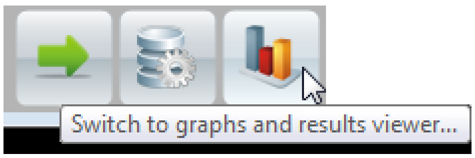
The Results page displays data from both the performance model and financial model. You can export data from any graph or table displayed on the Results page to Excel or text files.

To display the Results page:

- Click Run to run simulations and display the Results page.



Or, click Switch to Results to show the Results page without running simulations.



Note. If you try to display the Results page before running simulations, and there are no results from an earlier simulation run, SAM displays variable names like *sv.annual_output* or *cf.energy* because there are no results to display. If you see these variable names, click Run to generate results.

Performance Model Results

When you run simulations based on inputs you specify on the Systems pages in SAM, the performance model creates a file of hourly data called the simulation results file. There are several options in SAM for viewing data from this file:

Note. For some advanced simulations, the simulation file may contain data with a different time step.

- The Metrics table displays key metrics that summarize the performance model results, such as total annual electrical output, capacity factor, etc.
- Graphs displays monthly electrical output and an annual energy flow graph, and allows you to create your own graphs.
- Tables allows you to build custom tables of hourly, monthly, and annual results on the Results page.
- Time Series displays time series and statistical graphs of hourly data.

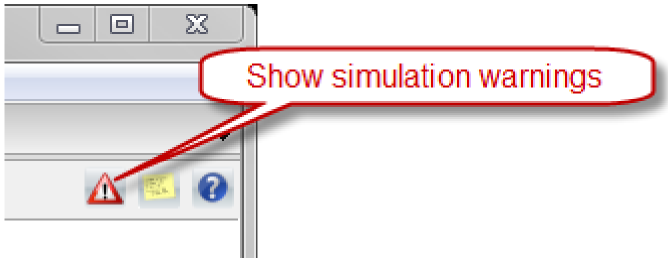
Financial Model Results

SAM's financial model uses the sum of the performance model's 8,760 hourly output values in kWh as an input representing the system's total annual electrical output in kWh. The financial model then calculates the project's cash flow based on the inputs you specify on the Costs and Financing pages. SAM displays financial model results in the following places:

- The Metrics table displays key metrics such as the LCOE, PPA price, IRR, and payback period.
- The Cash Flows table shows details of the project's cash flow.
- Tables allows you to build custom tables of cost and cash flow data along with metrics.

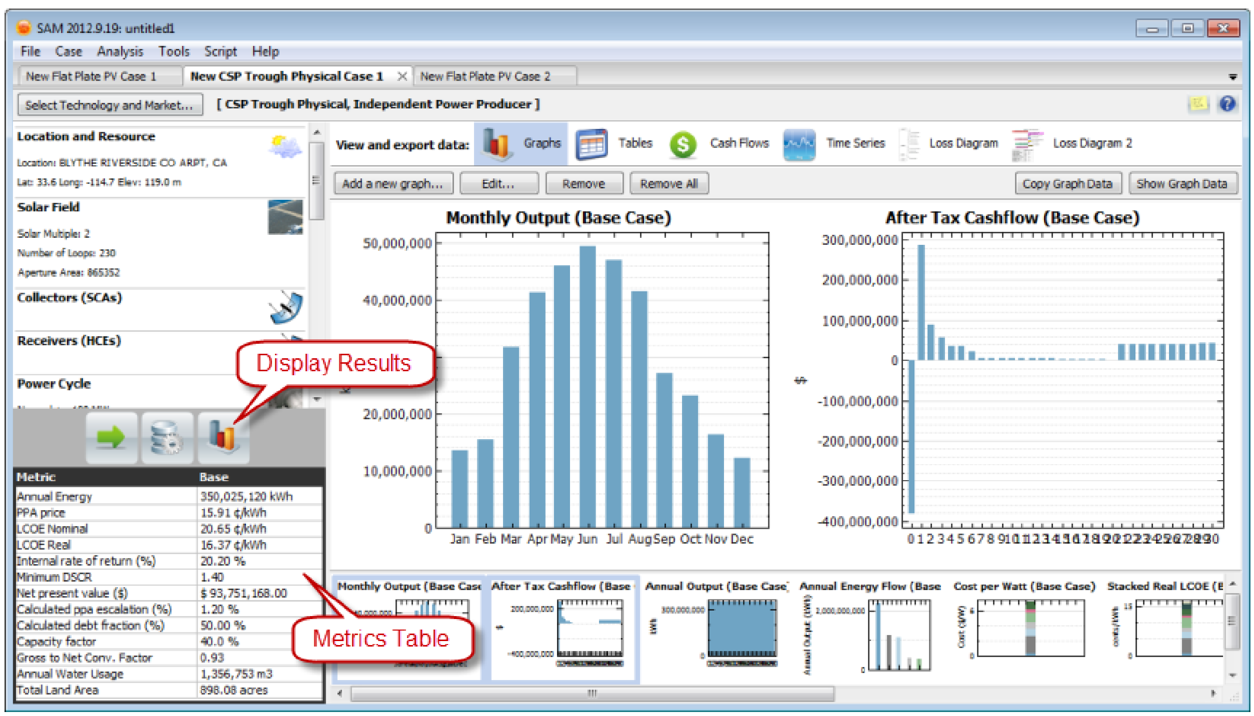
Simulation Warning Messages

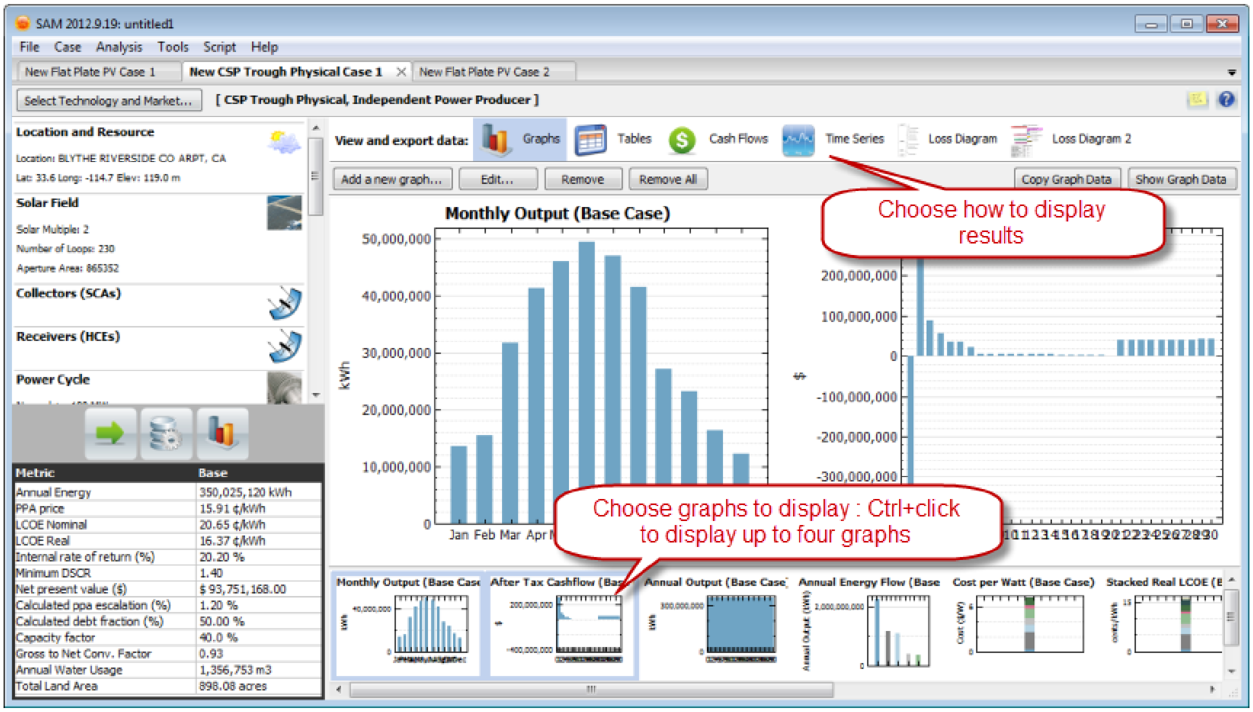
Under some conditions, SAM displays simulation warnings. When there are simulation warnings, the simulation warning button appears at the top right corner of the Results page. Click the Show Simulation Warnings button to view warning messages:



Screenshots

The Display Results button shows results for the last simulation without running a new set of simulations. If you show the Results page using this button after changing values on the input pages, the data on the results page will not match the inputs.





2.7 Export Data and Graphs

SAM provides several options for exporting data and graph images to other applications for further analysis or inclusion in reports and other documents.

Input Data

The input value summary is a list of all the input variables in a case with their values.

<u>To view the input value summary:</u>

- On the Tools menu, click **Export input variable list**, or press the F8 key.

The table lists input variables with the convention *[Input page name]*/*[Variable Name]*, where *{CALC}* indicates that the variable is for a calculated value rather than one that you can enter.

<u>To export the list of input variables:</u>

- Choose one of the options for exporting the variable lists.

Copy

Copies the table to your computer's clipboard so you can paste the data into another program.

Save

Saves the data to a comma-separated text file.

To Excel (Windows only)

Exports the data to Microsoft Excel.

Note. For files that contain more than one case, you can also display and export input variables along with results for one or more case using Case Compare.

Metrics Table

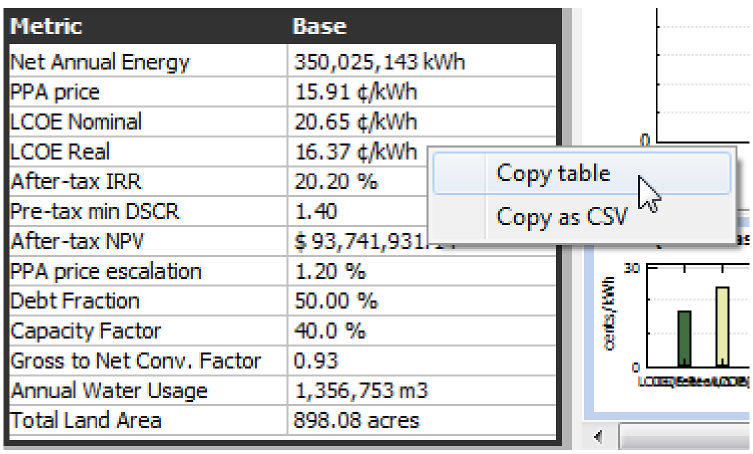
You can export data from the [Metrics table] either by right-clicking it and choosing an option to copy the data to your computer's clipboard, which you can paste into a spreadsheet or other document:

Copy table

Copies the metrics table to your computer's clipboard with columns separated by tabs.

Copy as CSV

Copies the metrics table to your computer's clipboard with columns separated by commas.



Note. You can choose Metrics table variables to display in the [data table], and export the values from there.

Results Graph Data

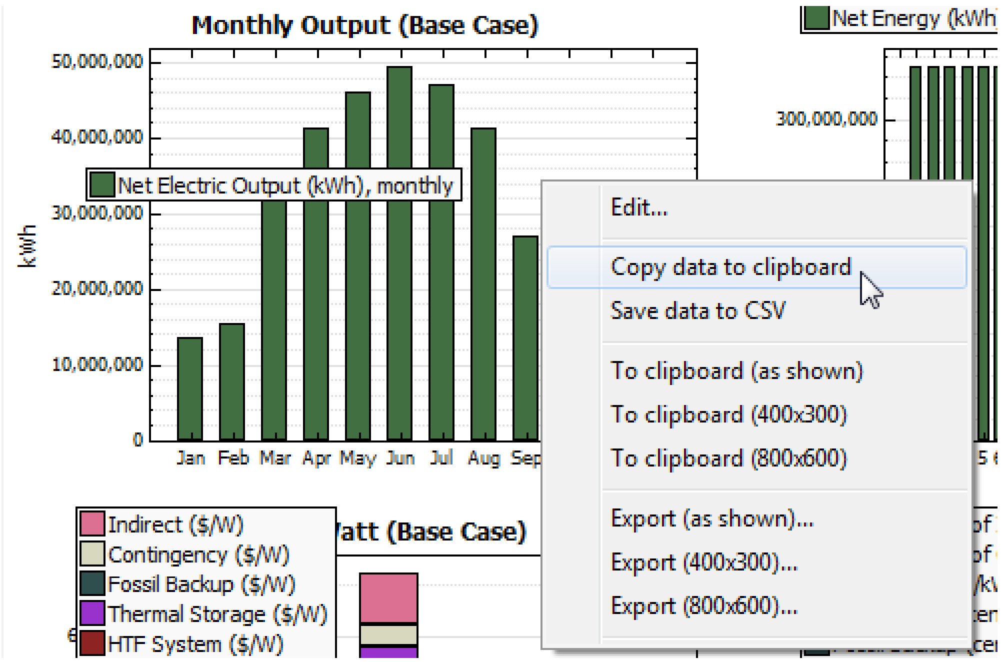
For most graphs on the [Results] page, you can export the data shown in the graph by right-clicking the graph and choosing one of the following options:

Copy data to clipboard

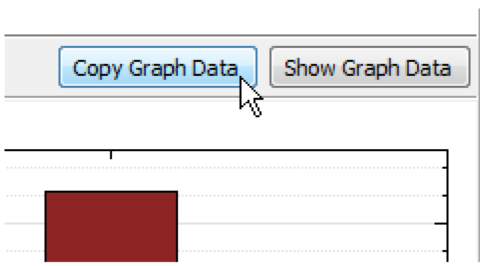
Copies the data visible in the graph to your computer's clipboard. You can then paste the data into another program or document.

Save data to CSV

Creates a comma-separated text file containing the data visible in the graph.



For the graphs you see on the Results page in Graphs mode, you can click **Copy Graph Data** to copy data visible in the graphs to your computer's clipboard. Click **Show Graph Data** to see a table of the data.



Results Graph Images

To export images of graphs, right-click the graph and choose options to copy the image to the clipboard or save it to a file, and to determine the size of the exported image.

You can export the graph image to the clipboard or to a file:

To clipboard

Place a copy of the graph image in your computer's clipboard.

Export

Creates a file of the graph image in BMP, JPG, or PNG format.

You can export the graph image with one of the following dimensions:

as shown

Export the graph image with the same dimensions you see on the screen.

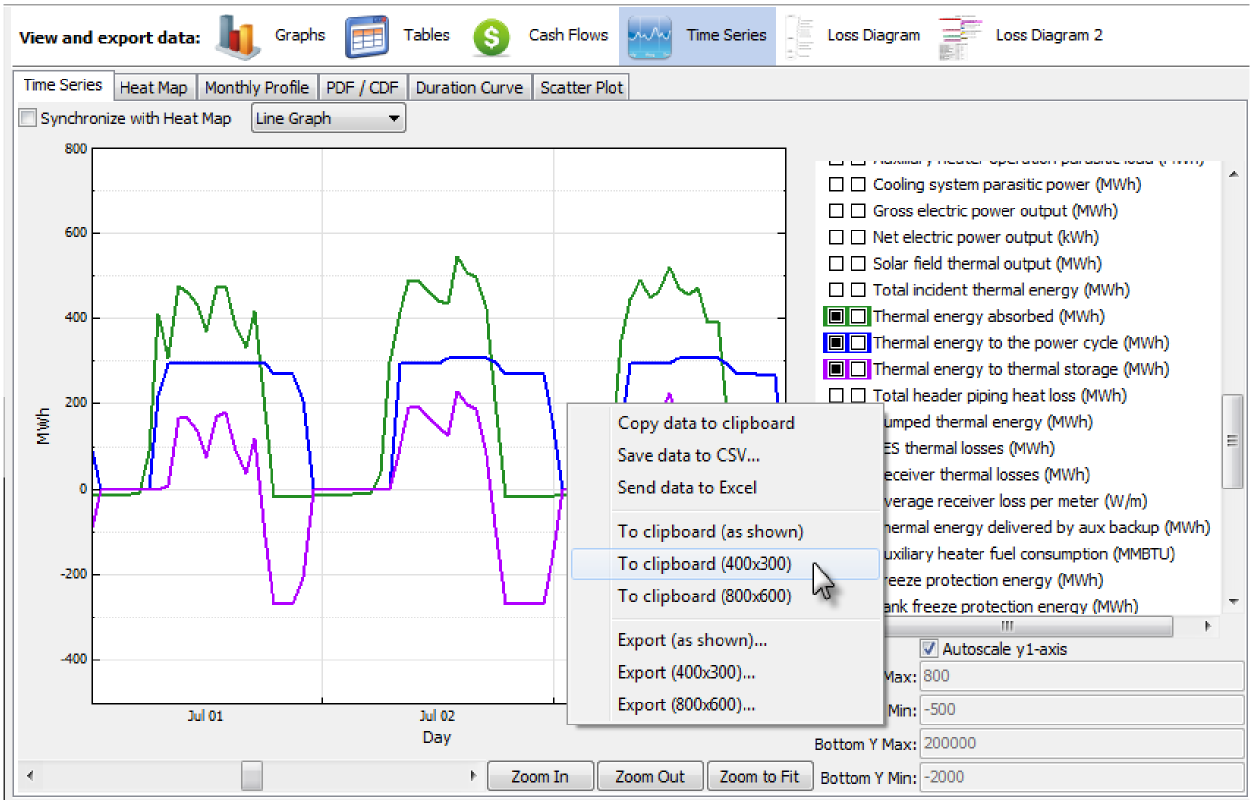
400x300

Scale the graph image to a 400 by 300 pixel rectangle before exporting it.

800x600

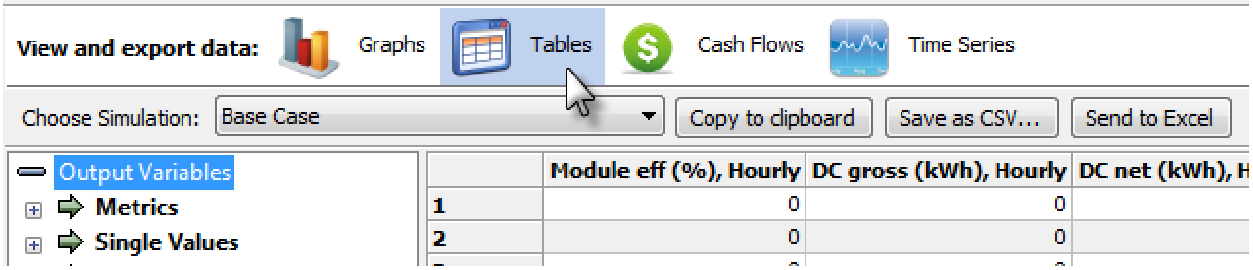
Scale the graph image to a 800 by 600 pixel rectangle before exporting it.

Note. For graphs that appear with a legend, if the legend is partially or completely hidden in the exported image, use your cursor to move the legend to a different position on the Results page and export the image again. Legends do not appear in the same position in the exported image as they do on the Results page.



Results Page Cash Flow and Tables

The Cash Flows table and Tables provide three options for exporting data shown in the tables:



Copy to clipboard

Copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.

Save as CSV

Saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.

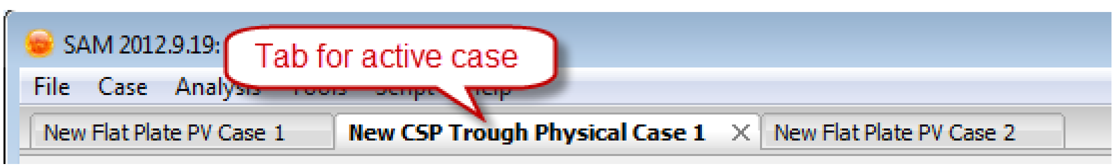
Send to Excel (Windows only)

Saves the table in an Excel file.

2.8 Manage Cases

A case is a complete set of input data and results. A project file contains at least one case. SAM uses tabs to display each case in the project, analogous to the way Excel displays worksheets in a workbook.

SAM indicates the active case name in bold type:



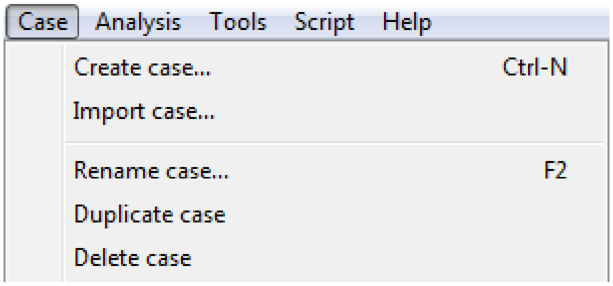
Note. The number of cases that a project file can contain depends on the storage and computing resources available on your computer. SAM displays a warning if you try to add more than six cases to your project. Your computer may be able to handle projects with more than six cases, but for the model to run efficiently, it is best to keep the number of cases to less than seven.

Why Use Cases?

By creating more than one case in a file, you can easily compare the assumptions and results of different analysis scenarios. For example, you could use cases to compare the cost and performance of a residential photovoltaic system in several locations by defining a separate case for each location, or you could compare a utility-scale photovoltaic and concentrating solar power systems.

Creating and Deleting Cases

To add, remove, and rename cases, used the four commands on the Case menu:



Create Case

Adds a new case to the project file. SAM displays the Technology and Market window for you to choose options for the case.

Rename Case

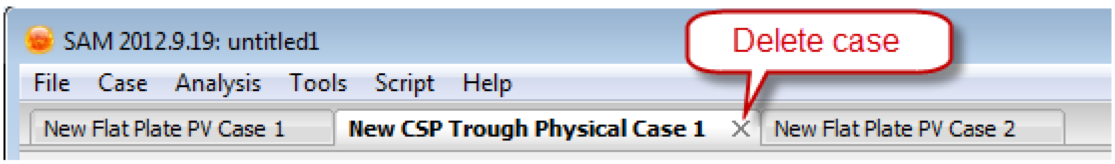
Change the label identifying the case that appears on the case tab.

Duplicate Case

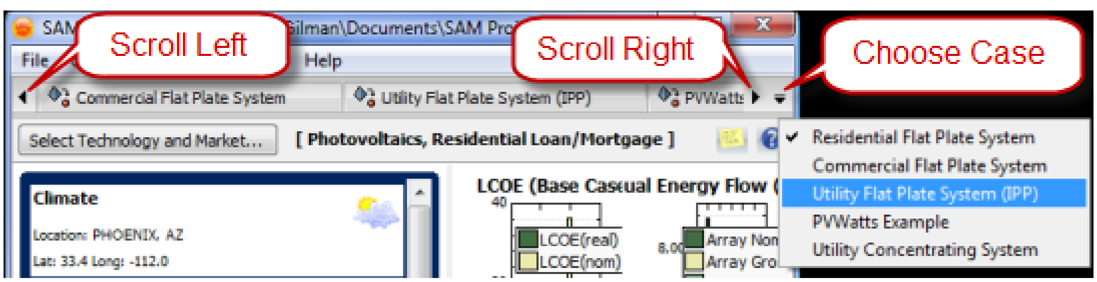
Creates a copy of the active case, with a duplicate set of input parameters and results.

Delete Case

Deletes the active case. You can also delete a case by clicking the 'x' on the case's tab.

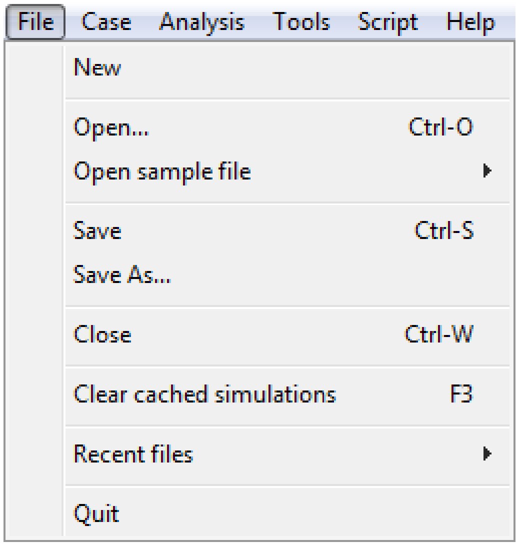


For projects with more cases than can be displayed on tabs, the scroll and list controls allow you to access all of the cases in the project.



2.9 Menus

SAM's menus provide access to commands for managing projects, running simulations, exporting results, and getting more information about the model.



New

Create a new file using default input values. SAM creates a zsam file with a single case and no results.

Open

Open an existing zsam file.

Open sample file

Open a sample file that contains a complete set of inputs and results. The submenu lists the available sample files. SAM creates a zsam file with inputs and results for one or more cases.

Save

Save the project as a zsam file in its current location.

This option saves annual and monthly results, but does not save hourly results to minimize the size of the file. When you open the file after closing it you will need to run simulations to view hourly data on the Results page.

Save with hourly results

Save the project as a zsam file in its current location, and include hourly results.

Use this option if you want hourly data to be available on the Results page when you next open the file after closing it.

Save As

Save the project as a zsam file in a different location or with a new name.

Close

Close the zsam file without exiting SAM.

Clear Cached Simulations

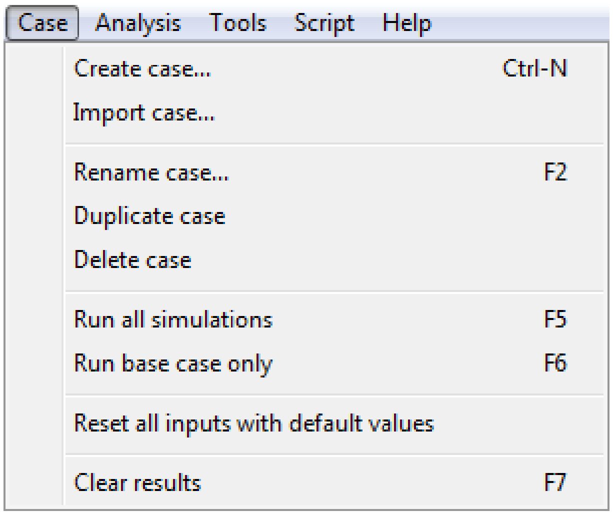
Clears stored results and other data from computer memory. Use this command if the program becomes sluggish after running a very large number of simulations, or if you are setting up very complex simulations and want to clear the cache before running them.

Recent Files

Open a zsam file from the recent files list.

Quit

Close the zsam file and exit SAM.



Create Case

Create a new case in the project. SAM opens the Technology and Market window where you choose options for the case. The new case will open with default input values and no results.

Import Case

Import one or more cases from another zsam file.

Rename Case

Change the name of the current case.

Duplicate Case

Create a copy of the current case.

Delete Case

Delete the current case. You can also delete a case by clicking the 'x' in the case's tab.

Run All Simulations

Runs all of the simulations configured in the current case. Equivalent to clicking the Run button.

Run Base Case Only

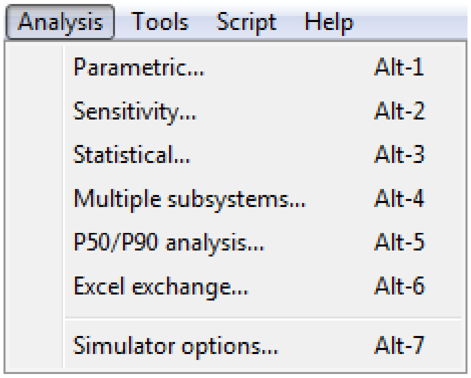
Runs a single simulation based on the input values shown on the input pages, ignoring any parametric, sensitivity, or other configurations requiring multiple simulation runs, and does not save hourly results.

Reset to Tech/Market Default Inputs

Replaces all values on input pages with default values.

Clear Case Results

Clears results from the current case. SAM removes any graphs you may have created for the case.



Parametrics

Displays the parametric analysis page allowing you to assign multiple values to input variables for parametric studies and optimization. See Parametric Analysis for details.

Sensitivity

Displays the sensitivity analysis page allowing you to specify a range of values to input variables for sensitivity analyses. See Sensitivity Analysis for details.

Statistical

Displays the statistical analysis page allowing you to explore uncertainty in input variables. See Statistical Analysis for details.

Multiple Subsystems

Displays the multiple systems page where you can build a system as a set of subsystems. See Multiple Subsystems for details.

P50/P90 Analysis

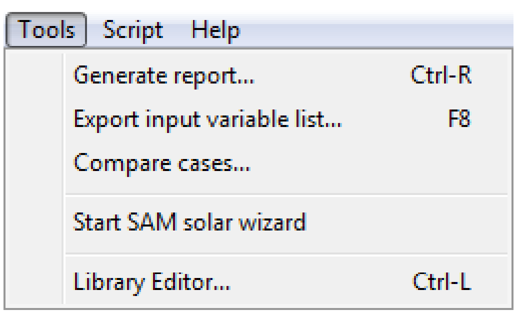
Displays a list of weather files for locations with data available for multiple year analyses. See P50/P90 Analysis for details.

Excel Exchange

Displays the excel exchange page where you can set up a data exchange between SAM and Excel when you want to use Excel to calculate values of SAM input variables. Excel Exchange works only with the Windows version of SAM. See Excel Exchange for details.

Simulator Options

Displays the simulator options page where you can specify the simulation time step and configure SAM to run custom TRNSYS decks. See Simulator Optionsfor details.



Create report

Generate a PDF report of inputs and results for the current case.

Export input variable list

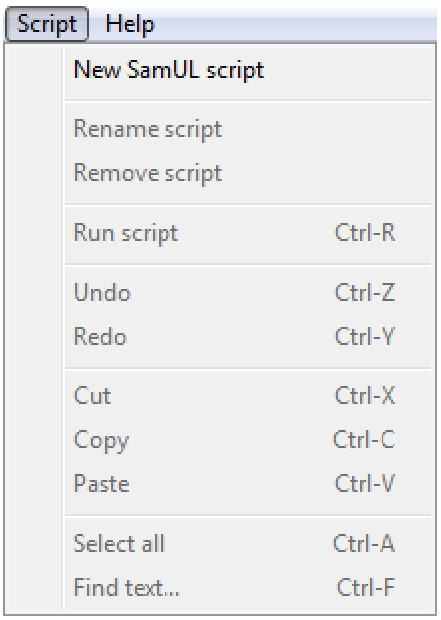
Displays a list of input variables with their values that you can copy and paste into documents and spreadsheets. In Windows, you can also export the table as an Excel workbook.

Compare cases

Open the Case Compare window to compare inputs and results for all cases in the file.

Start SAM solar wizard
Opens the solar wizard, which walks you through the steps to create a case using a small number of input variables.

Library Editor
Open the library editor to view or modify component libraries.



The Developer menu displays commands for the SamUL development environment.

New SamUL Script
Create a new script, which appears as a tab in the SAM file.

Rename Script
Change the script name that appears on the tab.

Remove Script
Delete the current script.

Run Script
Execute the code in the SamUL script.

Undo
Erase the last change in the script.

Redo
Revert last Undo action.

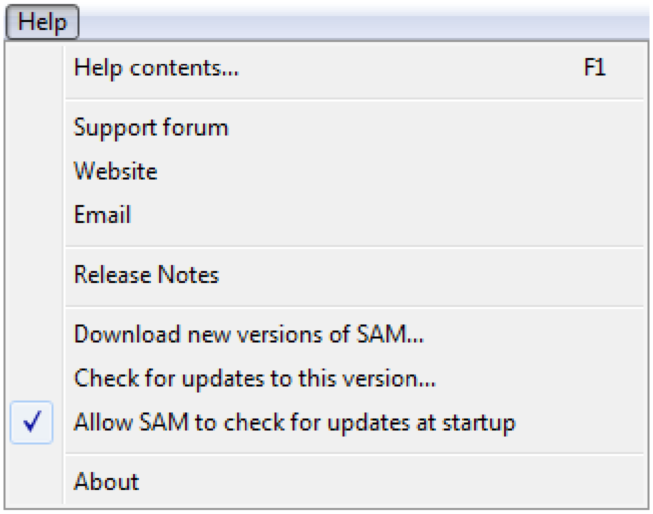
Cut
Delete selected text and store it in the clipboard.

Copy
Copy the selected text and store it in the clipboard.

Paste
Paste the contents of the clipboard.

Select All
Select all of the text in the script.

Find Text
Search the script.



Help Contents

Opens SAM's help system.

Support forum

Opens your computer's web browser to the SAM support forum page. (Requires an internet connection.)

Website

Opens the SAM website in your computer's default browser. (Requires an internet connection.)

Email

Opens your computer's default email client with an email addressed to the SAM support team at sam.support@nrel.gov. (Requires an internet connection.)

Release Notes

Displays SAM's version history.

Download New Versions of SAM

Opens the SAM website's download page. See Keep SAM Up to Date for details.

Check for updates to this version

Checks for updates to the version of SAM installed on your computer, and allows you install available updates. (Requires an internet connection.)

Allow SAM to check for updates at startup

When the checkmark is visible, each time you start SAM, it will check the SAM website to see if updates are available.

Clear the checkmark to disable this feature.

About

Displays the legal disclaimer and information about the version of your copy of the software.

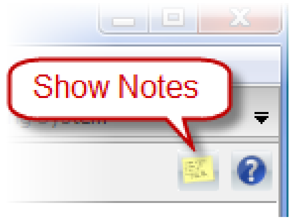
2.10 Notes

The Notes feature allows you to store text associated with each input page and with the Results page.

To create notes:

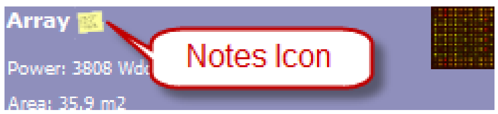
1. From any input page or the Results page, click the Show Notes button at the top right of the

window.



2. Type your text in the notes window.
3. Click the Notes window's close button to hide the window and save your notes.

   For input page notes, SAM displays a Notes icon in the navigation menu indicating that there are notes associated with the input page.



   For Results page notes, SAM opens the notes whenever you navigate to the page and after running simulations.

To delete notes:

1. Open the Notes window containing the notes you want to delete.
2. Select all text in the Notes window and press the Delete key.
3. Close the Notes window. SAM will remove the appropriate Notes icon from the navigation menu.

2.11 File Formats

SAM uses the following types of files to store and transfer data. The file formats are listed below by file extension in alphabetical order.

BMP

Graphics file format used to export graph images.

CSV

Text file containing a table of comma-delimited columns that the model uses to export results data from graphs and tables. Weather files in TMY3 format also use the CSV extension.

CBWFDB

File format used for P50/P90 analysis.

EPW

Weather file format.

OUT

Text file format generated by SAM performance models that use the TRNSYS simulation engine to store hourly simulation results.

SAMLIB

Text file used to store data for a SAM library.

SAMREPORT

File format used to store reports.

SCIF

An obsolete compressed file format used in SAM versions 2.5 through 3.0.

SMW

Special weather file format designed to work with the physical trough model and is designed to allow for sub-hourly simulations. The flat plate PV, PVWatts, and high-X concentrating PV models also read this weather format.

SUL

Text file containing SamUL script for automating SAM analyses.

SRW

Text file containing wind resource data for the wind power model.

TM2

Weather file format.

XLS

Excel files used to export data from SAM and to exchange data between the model and Excel. Note that Excel files must be in Excel 2003-2007 XLS format, and not in the newer XLSX format.

ZSAM

Files store project data, which includes inputs and results for one or more cases.

3 YouTube Channel

For video demonstrations of SAM, please visit the SAM Demo Video YouTube Channel at: http://www.youtube.com/user/SAMDemoVideos

Demonstration videos on the SAM YouTube Channel include:

- Use TMY3 Weather Files in SAM (Created September 2011)
- SAM Overview (Created April 2010)

Please feel free to leave comments on the site with suggestions for improving the videos, or for videos you would like us to add to the channel.

4 Weather Data

Each of the performance models in SAM requires data describing the renewable resource and ambient weather conditions at the project location.

For a general description of weather data in SAM, see Weather Data Overview.

For a description of the weather data inputs, see:

- Weather Data Viewer describes options for viewing graphs and tables of data in your weather files.
- Weather File Folders explains how to store weather files on your computer where SAM can find them.
- Create a TMY3 File explains how to use SAM's TMY3 Creator to use your own weather data in SAM.
- Embed a Weather File explains how to include a weather file in your SAM file to share with other people.
- Download Weather File explains how to use SAM to download weather files from NREL's Solar Prospector web service.
- Download Weather Files describes online sources of weather files and how to use them.
- Weather File Formats describes the file formats SAM's weather data processor can read.
- Location and Resource describes the Location and Resource page for solar technologies, including photovoltaic, concentrating solar power, and solar water heating systems.
- Wind Resource describes the Wind Resource page for the Wind Power model.
- Location and Ambient Conditions describes the Location and Ambient Conditions page for the biopower model's power block.
- Ambient Conditions describes the Ambient Conditions page for the geothermal model's power block.

4.1 Weather Data Overview

SAM's performance models use data from a weather file to simulate a system's hourly performance for a single year. Each performance model requires weather data that describes the energy resource and ambient conditions at the project location.

The weather data required by the performance model depends on the technology. You choose the weather data on the following input page, depending on the performance model:

- All solar technologies: Location and Resource
- Wind power: Wind Resource
- Biopower: Location and Ambient Conditions
- Geothermal power: Ambient Conditions

Because SAM's financial models use multi-year cash flow calculations, SAM is designed to work with typical year weather data that describe weather conditions over a long time period. This makes it possible to use a single year of data to represent a system's annual electricity output over many years. When you run simulations, the performance model uses hourly data from the weather file to calculate the quantity of electricity generated by the system in one year by summing the 8,760 hourly generation values. The financial model assumes that this value is the amount of electricity the system generates in each year of the analysis period on the Financing page. If you specify a non-zero **Year-to-year decline in output value** on the Performance Adjustment page, then the financial model assumes that the system's electricity output decreases from year to year throughout the analysis period.

For some analyses, it may be appropriate to use single year data instead of typical year data. For example:

- To model a system's performance (ignoring the financial model inputs and results).
- To explore savings and revenue when electricity prices are weather dependent, for example, in a location with hot summers and electricity prices that increase with demand to meet summer cooling loads.
- For statistical studies involving single year data for many years, such as for P50/P90 analysis.

Note. For a good discussion of weather data for renewable energy modeling, see Stoffel T et al, 2010. Concentrating Solar Power Best Practices Handbook for the Collection and Use of Solar Resource Data. National Renewable Energy Laboratory NREL/TP-550-47465. http://www.nrel.gov/docs/fy10osti/47465.pdf. Although the handbook was written with CSP technologies in mind, the information is useful for other technologies.

Weather Data Elements Used by Each Performance Model

Each performance model uses different data elements from the weather file.

The following abbreviations represent the different performance models in the table below:

- PVFP: Flat Plate PV
- PVW: PVWatts
- HCPV: High-X concentrating PV
- CSP: Concentrating solar power, includes Parabolic Trough - Physical, Parabolic Trough - Empirical, Power Tower - Molten Salt, Power Tower - Direct Steam, Linear Fresnel, Dish Stirling, and Generic Solar System
- SWH: Solar Water Heating
- GP: Geothermal Power
- BP: Biomass Power
- WP: Wind Power

Note. The generic system and geothermal co-production models do not use weather data.

Weather Data Element	PVFP	PVW	HCPV	CSP	SWH	GP	BP	WP[4]
Latitude (decimal degrees)	•	•	•	•	•			
Longitude (decimal degrees)	•	•	•	•	•			
Elevation above sea level (m)	•		•	•	•			•
Hour of the day	•	•	•	•	•		•	
Diffuse horizontal radiation (W/m²)	• [2]	•	•					
Direct normal radiation (W/m²)	•	•	•	•	•			

Weather Data Element	PVFP	PVW	HCPV	CSP	SWH	GP	BP	WP[4]
Global horizontal radiation (W/m²)	• [2]				•			
Albedo	• [3]	• [3]						
Atmospheric pressure (mbar)(1)				•		•	•	•
Dry bulb temperature (°C)	•	•	•	•	•	•	•	•
Dew point temperature (°C)				•				
Wet bulb temperature (°C)				•		•	•	
Relative humidity (%)				•		•	•	
Wind velocity (m/s)	•	•	•	•			•	•
Wind direction (degrees)								•
Snow depth		•[3]						

[1]Weather files in EPW format store pressure data in Pa. SAM converts those values into mbar.

[2]For the flat plate PV model, the **Radiation Components** settings on the Array page determine whether SAM uses the diffuse or global horizontal radiation value. By default, SAM uses the beam and diffuse components and ignores the total horizontal radiation from the weather file.

[3]The PVWatts model uses the albedo and snow depth values only if it is available in the weather file. The flat plate PV model provides an option on the Array page where you can choose whether to use the albedo value from the weather file or the value you specify on the Array page.

[4]The wind power model requires wind speed, velocity, and temperature data at three different heights above the ground. See Weather File Formats for details.

Typical Year and Single Year Weather Data

SAM can simulate systems using either typical year data representing the resource and weather at a given location over a multi-year period, or single-year data.

> **Note.** A file in the TMY2 (.tm2) or TMY3 (.csv) weather file format may contain either typical year data or single year data. The file format defines how the data is stored in the file, not the time span that the data represents.

Typical Year Data

A typical year file uses a single year of hourly data to represent the renewable resource and weather conditions over a multi-year period. The typical year methodology involves analyzing a multi-year data set and choosing a set of 12 months from the multi-year period that best represent typical conditions over the long term period. For example, a typical year file developed from a set of data for the years 1998-2005, might use data from 2000 for January, 2003 for February, 1999 for March etc. Annual simulation results from typical year weather data are suitable for long-term economic analysis.

The following are examples of weather data files that contain typical year data:

- TMY2 files from the National Solar Radiation Database included with SAM.
- The representative wind data files (SRW) included with SAM.
- TMY3 files from the National Solar Radiation Database website.
- EPW files from the EnergyPlus website.
- TMY, TDY, or TGY files in TMY2 format from the Solar Prospector database.

Single Year Data

Single year data represents the weather at a location for a specific year. Single year data is appropriate for analysis of a system's performance in a particular year, and may be appropriate for analyses involving time-dependent electricity pricing or electric loads for a given year.

The following are examples of weather files that contain single-year data:

- Wind data files (SRW) from the NREL Wind Integration Dataset.
- Single-year data in TMY2 format from the Solar Prospector database.

Time Convention and Sun Position

The time convention of the weather data file determines the time convention of SAM's simulations. You should refer to the weather file documentation for a description of the time convention in the file you are using.

For example, for the TMY2 and TMY3 weather file formats from the NREL National Solar Radiation Database store hourly data with the time stamps that refer to local standard time. In those files, the solar radiation values represent the total energy received during the 60 minutes preceding the indicated hour. The global horizontal radiation shown for hour 1 represents the total radiation incident on a horizontal surface between midnight and 1:00 am of the first hour of the year. Both data sets assume that there are 8,760 hours in one year and do not account for leap years. SAM assumes that the solar angle at the middle of the hour (at 30 minutes past the hour) applies to the entire hour. The wind speed, ambient temperature, and humidity values are instantaneous values at the end of the hour

During simulations, SAM's solar performance models use the sun position at the midpoint of each time step for sun angle and incident angle calculations. For the sunrise hour, the sun position is at the midpoint between sunrise time and the end of the time step. Similarly, for the sunset hour, the sun position is the midpoint between the beginning of the time step and sunset time. The air mass calculation uses the site elevation value from the weather file header and the solar zenith angle calculated for each time step.

Because SAM's performance models calculate values at the midpoint of the time step, the weather processing algorithm converts values so that the calculations correctly represent the values during simulations.

For time-dependent pricing calculations, SAM assumes that first hour of the year is the hour ending at 1 am on Monday, January 1.

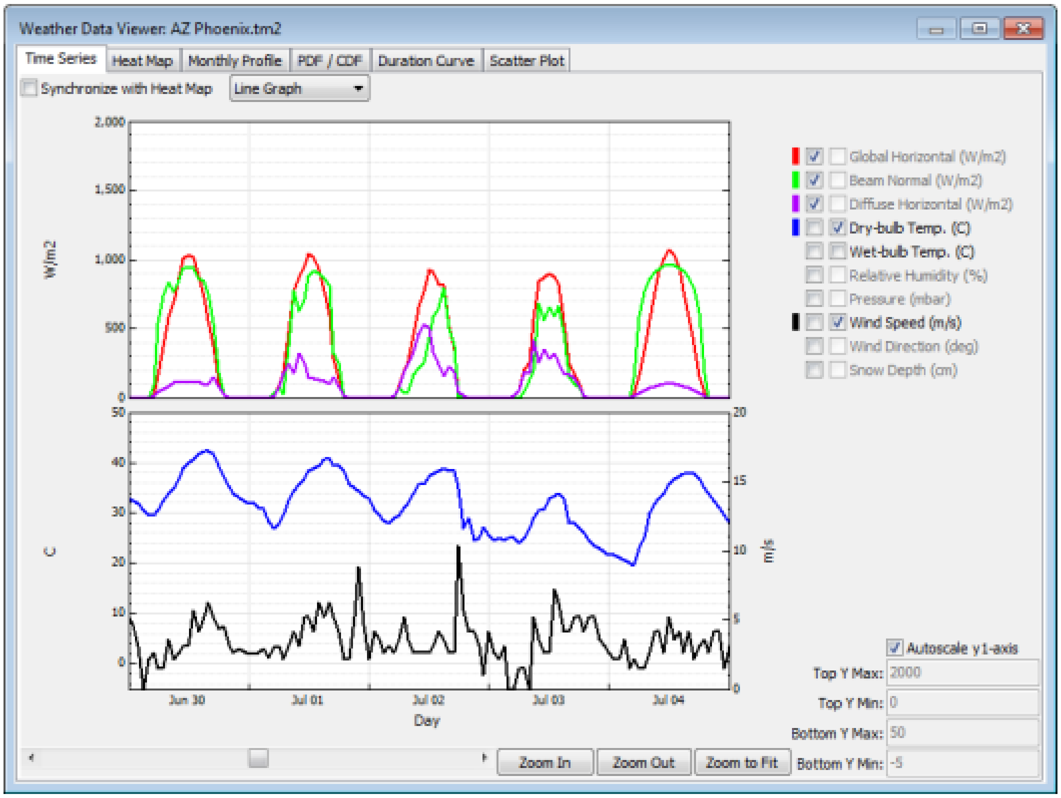
4.2 Weather Data Viewer

SAM displays summary data from a weather file. If you want to see the weather data itself, you can use the weather data viewer to display data from the weather file.

To learn about the weather data viewer controls, see Time Series Data Viewer.

To open the current weather file in the data viewer:

- Click **View Hourly Data**.



Alternatively, to view the data in a weather file, you can:

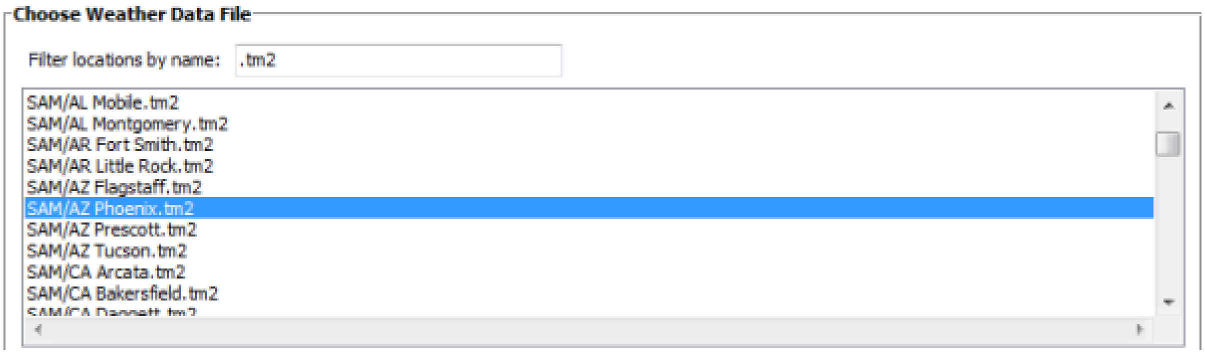
- Use the DView software to open the weather file. You can download DView at http://www.mistaya.ca/software/dview.htm.
- Use a spreadsheet program or a text editor to open the file.

Important Note! If you use Microsoft Excel to open a weather file in one of the comma-delimited formats (TMY3 and EPW), do not save the file! Excel reformats CSV files by adding commas to header rows and changing date and number formats in a way that renders the weather file unreadable by SAM. If you want to use Excel to modify values in a weather file, after modifying the data, use SAM's TMY3 Creator to create a new weather file with the modified data.

4.3 Weather File Folders

When you install SAM, it creates a default weather file folder in the SAM installation folder (C:\SAM\SAM 2014.1.14\weather by default in Windows). The default folder contains the complete set of TMY2 files from the NSRDB database, a set of typical wind resource files, and a few sample weather files in other formats.

Those files appear in the weather file list on the Location and Resource, Ambient Conditions, or Wind Resource page:



SAM can read weather files stored in any folder on your computer. Because the default folder can be difficult to find, we recommend that you create an easy-to-find folder to store weather files that you download from the web, create with the TMY3 Creator, or from another source.

In order for your weather files to appear in the list, you must add one or more folders containing weather files to the list weather file search paths as described below.

Note. If you store your weather files in the installation folder, you may lose them when you uninstall old versions of SAM.

SAM weather files must meet the following requirements:

- Be stored in a folder on your computer that you have specified as containing weather files, or in the default folder.
- Be correctly formatted in the TMY2, TMY3, EPW, SMW or SRW format.

To specify a folder as containing weather files:

1. On the weather file input page, click **Folder Settings**.
2. In the Weather Data Settings window, click **Add**.
3. Navigate to the folder on your computer that contains the weather file(s).

   You can add as many file search paths as you wish.
4. Click **OK** to return to the input page.

   SAM displays the search paths you added at the end of the list of weather files.

   To remove a search path from the list, click **Folder Settings** to open the Library Settings window, select the search path and then click **Remove**. Note that removing a search path does not delete any weather files.

To specify the folder for weather files you download with the Download Weather File feature:

1. On the weather file input page, click **Folder Settings**.

2. In the Weather Data Settings Window, under **Folder for Downloaded Weather Files**, navigate to the folder where you want to store downloaded weather files. You can specify a folder that is the same as one under **Weather File Folders**, or a different folder.
3. Click **OK** to return to the input page.

4.4 Create TMY3 File

SAM's TMY3 creator is a tool for converting your own weather data into the TMY3 format.

Although it is possible to create your own TMY3 weather file outside of SAM, or to use your data in one of the other weather file formats, using the TMY3 Creator will help you avoid data formatting issues that can render a weather file unreadable by SAM's weather data processor. For example, the following problems will cause SAM's weather file reader to fail:

- Incorrectly formatted dates or decimal values.
- Data with the wrong units.
- Empty columns or cells, even for a data element that the performance model does not use.

Note. The TMY3 Creator is not available for the wind power or geothermal co-production models because those models use resource data in different formats.

To open the TMY3 Creator:

- Click **Create TMY3 File**.

The TMY3 Creator allows you to use your own weather data in SAM, and helps to ensure that the data is correctly formatted. Although SAM only uses some of the columns of data in a TMY3 file, the weather file reader will fail if any of the columns in the file contain incorrectly formatted data because it reads the weather file before the performance model simulations begin.

Using the TMY3 Creator involves three overall steps:

1. Open an existing, correctly formatted TMY3 file to use as a base file.
2. Type and paste data in the the tables in the TMY3 Creator window to replace data in the base file with your data.
3. Save the data to a new TMY3 file.

Notes.

Unless you have a complete set of weather data for your location that you can use with confidence, using your own data introduces uncertainty into your analysis, and may result in inaccurate results or simulation errors.

As an alternative to the TMY3 Creator, if you plan to use your weather data with the physical trough model or one of the photovoltaic models, you may want to create a weather file in the SMW format.

To use the TMY3 Creator, you must have the following:

- A "base" TMY3 file, which is an existing file in TMY3 format that SAM modifies by replacing only the columns that SAM needs for simulations with your data. If you have a complete data set that includes all of the columns shown in the table below, then you can use any valid TMY3 file as a base file. If you do not have data for all of the categories listed in the table below, you may want to use a base file with data for the same or a nearby location with similar weather characteristics.

- Hourly data (8,760 rows) for each of the data columns shown in the table below with no gaps. If you do not have data for one or more of the columns, you can choose to not replace data for those columns, and instead use data from the base file. This will result in a data set that SAM can read but with mismatched elements that may cause inaccurate results or errors in the simulation. In some cases, you maybe able to use a null value indicator such as 999 or -999 for columns or cells for which you have no data.

A Note about Excel and TMY3 Files.

Opening TMY3 files in Excel and saving them can cause the data in the files to become unreadable in SAM:

1. Excel adds commas to the header rows to match the number of columns in the data rows because it assumes that all rows in the file have the same number of columns.

2. Excel automatically changes date and number formats so that SAM's weather data processor can no longer recognize the data, for example changing 01/01/1987 to 1/1/1987.

To avoid these problems, do not open and save your TMY3 format files in Excel. To examine the data, use a program like DView (http://www.mistaya.ca/software/dview.htm) or a text editor. If you do use Excel to make changes to data in a TMY3 file, you can avoid the inadvertently changing the data format by using the TMY3 Creator to create a new file containing your modified data.

To prepare your data:

1. Identify a file in TMY3 format to use as the base file (see description above). This can be any of the following:
   - One of the TMY3 files included with SAM in the *\weather* folder of you SAM installation folder (*c:\SAM\SAM 2014.1.14* in Windows*)*. The TMY3 files have the *.csv* extension, for example, *723815TY.csv*.
   - A TMY3 file for a location near your weather file location from the NSRDB database http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/.
   - A valid TMY3 file that you created for a different location, and tested in SAM.
2. To facilitate copying and pasting data, create a spreadsheet with tables of data that match the two TMY3 Creator tables: One containing a row of header information (Site Identifier Code, Station Name, etc.), and the other containing columns of weather data. Organize the columns in your spreadsheet so that they are in the same order as those in the TMY3 Creator tables.

To create a TMY3 weather file:

1. Open the file or files containing your weather data in a spreadsheet program or any software that allows you to copy columns of 8,760 rows to your computer's clipboard.
2. Start SAM, and create a new case for the technology you want to use with your weather data.
3. On the Location and Resource page, click **Create TMY3 file**.
4. In the TMY3 Creator window, click **Open base TMY3 file**, and navigate to the folder containing the

base file.

5. Type values in the header fields as appropriate. See below descriptions of the fields.

   If you have organized the data in your spreadsheet as a table with columns in the same order as they are in the TMY3 Creator: Select and copy the entire table in the spreadsheet (without column headings), click the first column in the TMY3 Creator table, and click **Paste** to populate the entire table.
6. In your weather data file, copy the column of global horizontal radiation data. Be sure to copy all 8,760 rows of data, but do not include the row header. The column should contain 8,760 rows of numbers.
7. In the TMY3 Creator window, click the **GHI (W/m2)** column heading. SAM should highlight the entire column in dark gray.
8. Click **Paste**.
9. Repeat the copy and paste procedure for each column until you have pasted all of your data into the table.

   Alternatively, you can copy and paste the entire 9 x 8760 table as described under Step 6 above.
10. Click **Save as TMY3 file** (at the bottom of the window).

    Save the file in a folder that you have included in the weather file search list, or to a folder that you plan to add to the list. See Weather File Folders for details.
11. Click the close button at the top right of the window, or click **Cancel and Discard Data** to close the TMY3 Creator.
12. Click **Refresh list**. SAM may take a moment or two to refresh the location list.
13. In the Location list, select the new TMY3 file. You should find it toward the end of the list.
14. Click **View Hourly Data** to open the time series data viewer and visually inspect the data.

After creating and loading your weather file, run some test simulations and examine the time series results to see if there are any problems with the data. You can view graphs of the data with the weather data viewer.

Header Data

Site Identifier Code

A six-digit number identifying the location. If you do not have a station code, use a dummy value like 999999.

Station Name

A text description identifying the location. The station name must contain at least one character.

Station State

A two-letter text abbreviation for the location's state. If you do not have a state abbreviation, use a dummy value like NA.

Site Time Zone (GMT)

The location's time zone offset from Greenwich Mean Time (GMT) with no daylight savings adjustment. A positive value indicates a time zone east of the Prime Meridian. Decimals indicate fractions of hours. A negative value indicates a time zone west of the prime meridian. For example, Chicago is -6; India is 5.5.

Site Latitude (DD)

Location's latitude in decimal degrees. A positive value between zero and 90 indicates a latitude north of the equator. A negative value between 0 and -90 indicates a latitude south of the equator. For example, Durban (South Africa) is -29.97; New York City is 40.71.

Site Longitude (DD)

Location's longitude in decimal degrees. A positive value between zero and 180 indicates a longitude east of the Prime Meridian. A negative value between zero and -180 indicates a longitude west of the Prime Meridian. For example, Durban (South Africa) is 30.95; New York City is -74.01.

Site Elevation (m)

Location's height above sea level in meters.

Hourly Data

GHI (W/m2)

Global horizontal irradiance: Total amount of direct and diffuse solar radiation received on a horizontal surface Watts per square meter.

DNI (W/m2)

Direct normal irradiance: Amount of solar radiation received within a limited field of view centered on the sun in Watts per square meter.

DHI (W/m2)

Diffuse horizontal irradiance: Amount of solar radiation received from the sky, excluding the solar disk on a horizontal surface in Watts per square meter.

Dry-bulb (C)

Average dry bulb temperature for the hour in degrees Celsius..

Dew-point (C)

Average dew point temperature for the hour in degrees Celsius.

RHum (%)

Average relative humidity for the hour.

Pressure (mbar)

Station pressure or measured atmospheric pressure in millibars corrected for temperature and humidity for the hour.

Wspd (m/s)

Average speed of the wind for the hour in meters per second.

Albedo (unitless)

Ratio of reflected solar radiation to global horizontal radiation. Use -99 for null.

4.5 Embed a Weather File

When you want to share a SAM project with another person, and the project uses one or more weather files that the other person does not have, you can include a copy of the data from the weather files in the SAM file. Embedding a weather file increases the size of the SAM file, but also makes it more portable.

To copy data from a weather file to the project file:

1. Choose the weather file from the Location list.
2. Click **Copy to project**.

   SAM adds the file to the location list with the "USER/" prefix, indicating that the data is included in the SAM project file.

   To remove an embedded file, select it from the list, and click **Remove from project**.

4.6 Download Weather File

SAM's Download Weather File feature allows you to type an address, zip code, or latitude and longitude to download a weather file data for locations in the United States. The weather file that SAM downloads depends on the technology:

- For solar technologies, SAM downloads a file from NREL Solar Power Prospector database.
- For wind, the weather file comes from the NREL Wind Integration Datasets.
- For geothermal and biopower, SAM downloads a file from the NREL Solar Power Prospector database. SAM uses data from the weather file to represent ambient conditions for the power cycle. For these models, the weather file data does not represent the system's primary energy resource.

> **Notes.**
>
> SAM's Download Weather File feature uses the Google Maps API Geocoding Service service to identify the geographic coordinates of a location. To use the feature, your computer must be connected to the Internet.
>
> For information about downloading weather files and data from other sources, or for locations outside the United States, see Weather Data Online.

Download Weather File is available on the following input pages:

- Location and Resource for the photovoltaic, concentrating solar power, and solar water heating models.
- Wind Resource for the wind power model.
- Location and Ambient Conditions for the biomass power model.
- Ambient Conditions for the geothermal power model.

To use the Download Weather File feature:

1. Click **Download weather file**.
2. If you have a street address or zip code for the site, click **Enter street address or zip code** and type a street address zip code, or latitude and longitude in the search box. For example, any of the following three lines will return results for a location in Golden, Colorado:

   golden colorado
   15013 Denver West Parkway, Golden CO
   80401

   If you have a latitude and longitude for the site, click **Enter location coordinates (deg)**, and type the site's coordinates in the Latitude and Longitude boxes. For example:

39 44 N, 105 09 W
39.75, -105.15

3. For **Select data year**, choose a year to download a file for a specific year. You can only download a single file at a time.

   For some data sets, you can choose to download a typical year file.

4. Click **OK** to download the file.

   SAM stores the file in the weather file folder that you specify in the Weather Data Settings window. To change the location of the folder, click **Folder Settings**.

Solar Power Prospector

The Download Weather File feature for the following performance models downloads weather data from NREL's Solar Power Prospector database:

- Photovoltaic
- Concentrating solar power
- Solar water heating
- Biopower
- Geothermal

The NREL Solar Prospector database contains satellite-derived data in weather files with the TMY2 format for single years between 1998 and 2009.

It also contains three kinds of typical year data files:

- TMY is typical meteorological year data, and uses the National Solar Radiation Database's TMY weighting methodology described in the TMY3 User's Manual (PDF 1.7 MB). These files were originally designed for use with building simulation models. The typical months in these files are based on both the global horizontal and direct radiation in the long term data, and to a lesser degree on the temperature and wind speed data. These files may be most suitable for modeling non-solar technologies that use the weather data in the file (biopower, geothermal) to estimate thermal losses from the steam power cycle, or for modeling solar technologies.
- TDY is typical direct-radiation-year data. For these files, only the direct normal radiation in the long-term radiation data set is analyzed to choose the months to include in the typical data file. These files may be suitable for modeling solar technologies that use only the direct component of solar radiation incident on the collector such as the CSP technologies and concentrating solar power.
- TGY is typical global-radiation-year data with typical months chosen based only on the global horizontal radiation data in the long term data set. These files may be suitable for modeling solar technologies that use a flat collector such as photovoltaic and solar water heating.

Notes.

Although the files you download from the Solar Power Prospector website are in TMY2 format, they may contain TMY, TDY, TGY or single-year data depending on the option you choose when you download the files.

When you download weather data from the Solar Power Prospector website, SAM displays "satellitedata" for the city and "??" for the state because the Solar Prospector database does not include city and state names.

For a description of the data used for the Solar Prospector website, see:

- Perez, R et. al. A New Operational Satellite-to-irradiance Model -- Description and Validation, Manuscript Submitted to Solar Energy 4/2002.

For information about the Solar Power Prospector website, see:

- The Solar Power Prospector

For a discussion of the application of the Solar Prospector data for modeling of solar power systems in the context of other available weather data, see:

- Stoeffel T et al. Concentrating Solar Power: Best Practices Handbook for the Collection and Use of Solar Resource Data. 2010. NREL Technical Report. NREL/TP-550-47465.

Wind Integration Datasets

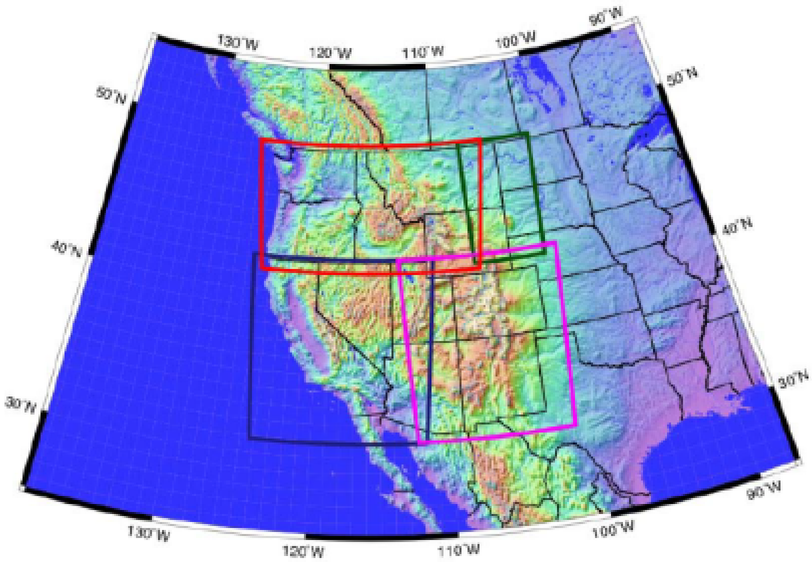
For SAM's wind power model, the Download Weather File feature allows you to download wind resource data from one of two databases, the Western Wind Dataset or the Eastern Wind Dataset, depending on the location you specify. SAM downloads the data and saves it in a file with the SRW format.

Western Wind Dataset

The NREL Western Wind Data set contains modeled wind resource data for about 32,000 locations roughly west of longitude 100° west in the western United States. For each location, the data set includes the following wind resource data:

- Atmospheric pressure at ground level
- Wind speed at 10, 20, 50, 100, and 200 meters
- Wind direction at 10, 20, 50, 100, and 200 meters
- Ambient temperature at 10, 20, 50, 100, and 200 meters

The following map shows the region covered by the Western Wind Dataset:



The data was produced for NREL by 3Tier using the WRF mesoscale model. For information about the data set, see the NREL Western Wind Dataset website.

The Eastern Wind Integration Set

The NREL Eastern Wind Dataset contains modeled wind resource data for about 1,300 locations roughly east of longitude 100° west in the United States, including some offshore locations off of the Eastern seaboard. For each location, the data set includes the following wind resource data:

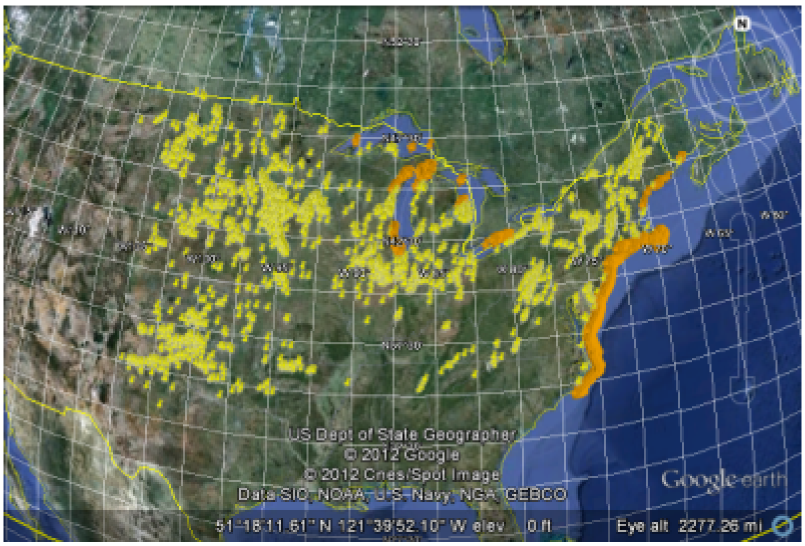
- Wind speed at 80 and 100 meters

When you use download data from the Eastern Wind Dataset, SAM displays a notice showing the distance between your location and the nearest available wind data location.

Because this data is insufficient for SAM's wind power performance model, when you download data from the Eastern Wind Dataset, SAM prompts you to provide additional data. See Specify Missing Wind Data Window for details.

Note. If there is no data available within a reasonable distance of your location, or if you do not have wind direction, temperature, and atmospheric pressure data to supplement the data set, you may want to use one of the representative typical wind resource files instead of the Eastern Wind Data file.

The following maps shows the locations included in the Eastern Wind Dataset:



The data was produced for NREL by AWS Truepower using the MASS mesoscale model. See NREL Eastern Wind Dataset website for more information.

4.7 Weather Data Online

SAM allows you to use correctly formatted weather files that you download from the web. Weather files must meet the following requirements:

- Be stored in a folder on your computer that you have specified in SAM as containing weather files. See Weather File Folders for details.
- Be in TMY2, TMY3, EPW, SMW, or SRW file format. See Weather File Formats for details.

This section describes how to download and use weather files from the NREL National Solar Radiation Database, EnergyPlus website, and from SAM weather file collections for India prepared by NREL, and for Australia prepared for the Australian Solar Thermal Energy Association (AUSTELA).

Note. If you cannot find weather data for your location on one of those websites, you may want to purchase data from one of the following companies (all links last accessed July 2013):

- Meteonorm
- SolarAnywhere
- SolarGIS
- Weather Analytics

NREL cannot guarantee that files from sources outside of NREL will work correctly in SAM.

NSRDB Typical Meteorological Year (TMY) data

NREL's National Solar Radiation Database (NSRDB) typical meteorological year (TMY) data represents average weather data over a range of years for locations in the United States. Each TMY file contains data from different years within the range. For example, a TMY file for a given location might contain 1995 data for the month of February, 2001 data for March, 1998 data for April, etc. The NREL typical year data is based on and analysis of solar radiation and meteorological data measured or modeled at each location. The NSRDB TMY files are appropriate for economic and performance predictions of a project over a long analysis period. For details about the methodology for developing the TMY data, see the user manuals on the NSRDB website.

There are two versions of the NSRDB TMY database, TMY2 and TMY3. The TMY2 files are available for 239 locations and represent the years 1961-1990. The TMY3 files are available for 1,020 locations and represent the years 1991-2005. The TMY3 database is an update of the TMY2 database and includes the 239 TMY2 locations. For those 239 locations, the time span in the TMY3 database is 1976-2005. The TMY3 data were developed from more recent data and better modeling techniques than the TMY2 data. However, the TMY3 data was developed using data from a shorter time period than the TMY2 data, so may be less representative of the resource over the long term. On the other hand, the TMY2 data includes effects from two major volcanic eruptions in 1981 and 1991 that reduced the solar resource during the TMY2 time period. If both TMY2 and TMY3 files are available for your project site, you may want to run SAM with both sets of data to compare results.

When you install SAM, it copies a the complete NSRDB TMY2 data set to the SAM installation folder on your computer. To use TMY2 data, you choose a location from the list on the Location and Resource page. To use an NSRDB TMY3 file, you must first download it from the web.

To download a TMY3 file from the web:

1. On the Location and Resource page, click the **Best weather data for the U.S. (1200 + locations in TMY3 format)** link to open the NSRDB TMY3 database page in your web browser.
2. On the NSRDB website, click the **In alphabetical order by state and city** link.
3. Scroll to the state and city at or nearest your location.
4. Click the identification code link for the location to download the TMY3 file.
5. Save the file in your SAM weather file folder. If you do not have a SAM weather file folder, see Manage Weather File Folders for instructions.
6. In SAM, on the weather file input page, click **Refresh**.

   The weather file should appear in the **Location** list, toward the bottom of the list.

EnergyPlus Weather (EPW) files: Data for locations outside the United States

You can download weather data in EPW format for locations around the world at no cost from the EnergyPlus weather data website at the following website:

- http://www.eere.energy.gov/buildings/energyplus/cfm/weather_data.cfm.

For information about the EPW weather files, see the following websites:

- For a description of the file format: http://apps1.eere.energy.gov/buildings/energyplus/weatherdata_format.cfm
- For a description of data sources: http://apps1.eere.energy.gov/buildings/energyplus/weatherdata_sources.cfm

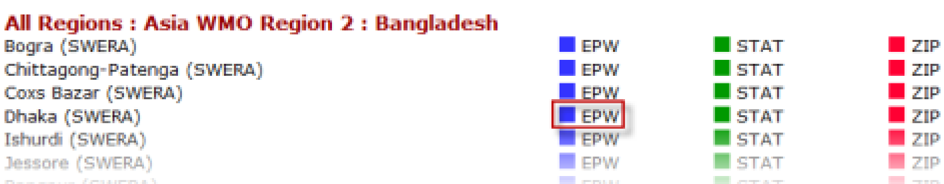
To download an EPW file:

1. On the Location and Resource page, click **Best weather for international locations (in EPW format)** to open the EnergyPlus Weather Files website in your web browser.
2. On the EPW website, navigate to the region, country, and location you want to model.
3. Download the EPW file for the location you are modeling.

   If there is not an EPW file for the location, download the ZIP file and extract the EPW file.
4. Save the file in your SAM weather file folder. If you do not have a SAM weather file folder, see Manage Weather File Folders for instructions.
5. In SAM, on the Location and Resource page, click **Refresh**.

   The weather file should appear in the **Location** list, toward the bottom of the list.

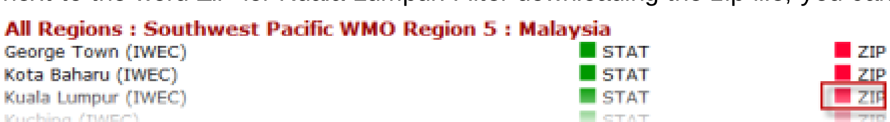
For some regions, you can download an EPW file directly for a location. For example, for Bangladesh, you can download the data for Dhaka by right-clicking the blue square next to the word EPW for Dhaka. Be sure to save the file with the *.epw* extension.



All Regions : Asia WMO Region 2 : Bangladesh

Bogra (SWERA)	EPW	STAT	ZIP
Chittagong-Patenga (SWERA)	EPW	STAT	ZIP
Coxs Bazar (SWERA)	EPW	STAT	ZIP
Dhaka (SWERA)	EPW	STAT	ZIP
Ishurdi (SWERA)	EPW	STAT	ZIP
Jessore (SWERA)	EPW	STAT	ZIP
Rangpur (SWERA)	EPW	STAT	ZIP

For other regions, you must first download a zip file containing the EPW file and then extract the EPW file. For example, for Malaysia, you can download the data for Kuala Lumpur by right-clicking the red square next to the word ZIP for Kuala Lumpur. After downloading the zip file, you can extract the EPW file.



All Regions : Southwest Pacific WMO Region 5 : Malaysia

George Town (IWEC)	STAT	ZIP
Kota Baharu (IWEC)	STAT	ZIP
Kuala Lumpur (IWEC)	STAT	ZIP
Kuching (IWEC)	STAT	ZIP

NREL India Weather Files for SAM

NREL has prepared a set of files in the TMY3 format (*.csv*) with single-year data between 2002 and 2008 for nine locations in India. This data is not typical-year data because there are not enough years for a typical-year analysis. You should run simulations using each of the seven years for a given location to get a sense of the range of values of your performance and financial metrics of interest. See the India SAM file documentation available from the website for a description of the data.

To download the NREL India Weather Files for SAM:

1. In your web browser, go to http://www.nrel.gov/international/ra_india.html.
2. On the website, under **India Weather Files Designed to be Used in System Advisor Model (SAM)**, download the *.zip* file for the location you want to model.

   Each ZIP file contains a set of weather files for a location in the TMY3 format (*.csv*) for a range of years.
3. Extract the CSV files and save them in your SAM weather file folder. If you do not have a SAM weather file folder, see Manage Weather File Folders for instructions to create one.
4. The weather files should appear in SAM on the Location and Resource page in the **Location** list, toward the bottom of the list. If you do not see the files, try clicking **Refresh**.

AUSTELA Australia Solar Data Files for SAM

IT Power Australia and NREL collaborated on a project supported by the Australian Renewable Energy Agency for the Australian Solar Thermal Energy Association to develop a set of SAM sample files and weather files. See the Australian Companion Guide to SAM for Concentrating Solar Power from the website for a description of the weather files.

To download the AUSTELA Australia Solar Data Files for SAM:

1. In your web browser, go to http://www.austela.org.au/projects.
2. On the website, click the **A selection of solar data files for input to SAM for selected representative Australian sites and years** link to download the *.zip* file.

   The ZIP file contains a set of weather files several locations in the TMY3 format (*.csv*) for a range of years, and the set of Australia weather files available on the EnergyPlus website in EPW format (*.epw*).
3. Extract the CSV and EPW files that you want to use and save them in your SAM weather file folder. If you do not have a SAM weather file folder, see Manage Weather File Folders for instructions to create one.
4. The weather files should appear in SAM on the Location and Resource page in the **Location** list, toward the bottom of the list. If you do not see the files, try clicking **Refresh**.

4.8 Weather File Formats

A SAM weather file is a text file that contains hourly data describing the solar resource, wind speed, temperature, and other weather characteristics at a particular location. For a description of how the different performance models use weather data, see Weather Data Overview.

SAM can read weather files in any of the five formats described below:

- TMY3, comma-delimited (.csv)
- TMY2, non-delimited (.tm2)
- EPW, comma-delimited (.epw)
- SRW, comma-delimited (.srw), a special SAM weather file format for the wind power model

- SMW, comma-delimited (.smw), a special SAM weather file format for sub-hourly simulations with the physical trough model

SAM can read a weather file in one of these formats that contains data from any source, as long as it is correctly formatted. You can create your own weather file with data from a resource measurement program or meteorological stations.

TMY3

The TMY3 file format is a comma-delimited text format with the extension *.csv*. The first row of a TMY3 file stores data describing the location's name, and the geographic coordinates, time zone, and elevation above sea level data required for sun angle calculations. The second row stores the column headings showing units for each data element. Rows 3-8762 store weather data elements used by SAM's performance models. Many of the data elements are not used by the SAM performance models.

> **Note.** Opening and saving a TMY3 file in Excel can cause formatting changes that renders the file unreadable by SAM's weather file reader. See the note in Create TMY3 File for details.

For a complete description of the TMY3 file format, see the TMY3 user's manual (PDF 1.7 MB) Tables 1-1 and 1-2 (p 3) describe the header data, and Table 1-3 (p 4-7) describes the weather data elements.

The TMY3 format is the most suitable for using your own weather data in SAM. You can use SAM's TMY3 Creator to convert your own weather data into the TMY3 format.

The TMY3 format is described in the TMY3 user manual available at http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/.

TMY2

The TMY2 file format is a text format with the extension *.tm2*. The TMY2 format is not delimited, which makes the data in the text file difficult to read. You can use SAM's weather data viewer to examine the data in a TMY2 file, or use another program like DView.

For a description of the data elements in the TMY2 format, see the TMY2 user's manual. The header elements are described in Table 3-1, and the weather data elements are described in Table 3-2.

The TMY2 user manual is available at http://rredc.nrel.gov/solar/old_data/nsrdb/1961-1990/tmy2/.

EPW

The EPW file format was developed for the U.S. Department of Energy's EnergyPlus building simulation model. EPW files store comma-delimited data, and use the extension *.epw*.

The first eight lines of a file in EPW format stores header data. SAM's performance models use only the latitude, longitude, elevation, and time zone data from the header to calculate solar angles. The remaining 8760 lines store weather data used by the SAM performance models and other data describing the quality of the data that SAM ignores.

For more details about the EPW format see the Weather Data Format Definition page of the EnergyPlus Simulation Software website.

The EPW weather file format is described at http://apps1.eere.energy.gov/buildings/energyplus/weatherdata_format.cfm.

SMW

The SMW format is a comma-delimited format with the extension *.smw*. The SMW format allows you to use weather data in different time steps.

> **Note.** In the current version of SAM, only the physical trough fully supports the SMW file format. The flat plate PV, PVWatts, and high-X concentrating PV models can read data from an SMW weather file, but only with hourly (3600 second) time steps.

The SMW weather file format differs from the standard TMY2 and TMY3 weather file formats in the following ways:

- It contains only the weather data elements used by SAM's solar models.
- It can contain weather data in time steps of one second or greater.
- All weather data values represent an instantaneous value at the mid-point of the time step. (For the standard TMY formats, the solar radiation values are totals over the hour, and temperature, wind speed, and other values are instantaneous at the end of the hour.)
- Weather data columns can be separated by commas, tabs, or spaces.

Here's what the first four rows of an SMW file with hourly data might look like:

723860,"Clark/El Dorado",NV,-8.0,35.796245,-114.974334,548.64,3600.,2010,0:30:00

5.15,-4.7,-999.,46.4225,0.65,295.0,941.97,0.0,0.016517,0.0,0.23,-999.

3.85,-4.1,-999.,54.1635,0.35,245.0,944.99,0.0,0.008,0.0,0.23,-999.

2.95,-3.85,-999.,58.752,0.3,225.0,945.785,0.0,0.08555,0.0,0.23,-999.

Header

The first row of an SMW file contains the header with the ten elements described in the table below separated by commas, and ending with a comma. The header columns cannot be separated by spaces or tabs.

The data in columns 1, 2, 3, 7, and 9 are not used by the current version of the physical trough model.

Table 1. Header line items by column number.

Column	Entry	Units	Example
1	Station/ID#	n/a	23161
2	Location name	n/a	“Daggett”
3	State	n/a	CA
4	Time zone	hours	-8
5	Latitude	deg	34.867
6	Longitude	deg	-116.783
7	Elevation	m	588
8	Time step	sec	3600 for time steps of one hour
9	Start year*	years	1970
10	Start time (time at mid-point of first time step)	hr:min:sec	0:30:00

*The start year has been included to make it possible to model calendar irregularities or holiday schedules, but is not used by the current version of SAM's SMW file reader.

Weather Data

The second row of an SMW file contains weather data for the first time step, indicated by column 8 of the header row. The number of weather data rows depends on the time step. For example, for a 3600 second time step, the file would contain 8,760 weather data rows.

Unlike the header information which must be comma-separated, the weather data columns can be separated by commas, tabs, or spaces. Each row may end with a separator character or not.

SAM's SMW weather file reader determines the time stamp for each row based on the start time and time step from the header and the row number.

You can indicate unused weather data elements with the value -999. For example, in the data shown above for the physical trough model, the global horizontal radiation, diffuse horizontal radiation, albedo, and snow depth columns contain the value -999 because the model does not use those elements.

Table 2: Weather data record format by column number.

Column	Entry	Units
1	Dry-bulb temperature	°C
2	Dew-point temperature	°C
3	Wet-bulb temperature	°C
4	Relative humidity	%
5	Wind speed	m/s
6	Wind direction	deg
7	Atmospheric pressure	mbar
8	Global horizontal radiation	W/m²
9	Direct normal radiation	W/m²
10	Diffuse horizontal radiation	W/m²
11	Albedo	none
12	Snow depth	m

SRW

The SRW format is a comma-delimited text format with the extension *.srw* for the wind power performance model. The format allows you to use wind resource data at one or more heights above the ground, and is designed to be flexible enough to handle a range of data:

- The file stores four data types: wind speed, wind direction, air temperature, and atmospheric pressure.
- The data can be for one measurement height or multiple heights. The measurement heights can be different for the different types of data. The file can contain air temperature, atmospheric pressure, and wind direction data at one height, and wind speed data at multiple heights.
- The file stores 8,760 values for a single year of hourly data.
- The file must contain a least one complete set of the four data types with 8,760 values.
- The direction measurement height must be within 10 meters of the nearest wind speed measurement height.
- The file must contain a wind speed measurement height within 35 meters of the turbine hub height.

Note. Although the weather file format allows for wind resource data at time steps smaller than one hour, the current version of SAM's wind power model is designed for hourly simulations, so the wind resource data must use a time step of one hour with 8,760 values.

After running simulations, SAM reports the hourly wind speed and wind direction on the Results page tables and time series graphs so you can see what values it used in simulations. For a general description of how the wind power model uses the data in the file, see Wind Power Overview:

- For a description of how SAM determines wind speed at hub height, see Hub Height and Wind Shear.
- For a description of how SAM uses temperature and pressure data from the weather file, see Elevation above Sea Level.

The following eight rows of sample data are for a correctly formatted SRW file containing wind resource data at four heights above the ground for Golden, Colorado. You can find examples of SRW files in the *\weather* folder in your SAM installation folder (*c:\SAM\SAM 2014.1.14* by default in Windows).

Sample Wind Resource Data.srw

```
1 8225,Golden,CO,USA,year??,lat??,lon??,1600,1,8760
2 Sample data for SAM Help file
3 Temperature,Pressure,Direction,Speed,Temperature,Pressure,Direction,Speed,Temperature,Pressure,Directio
4 C,atm,degrees,m/s,C,atm,degrees,m/s,C,atm,degrees,m/s,C,atm,degrees,m/s
5 50,50,50,50,80,80,80,80,110,110,110,110,140,140,140,140
6 14.327,0.954168,142,3.296,14.147,0.950823,145,3.376,13.877,0.947378,146,3.372,13.597,0.943933,146,1.165
7 14.197,0.953478,210,3.558,14.047,0.950035,197,3.667,13.837,0.946591,192,3.688,13.597,0.943245,192,1.164
8 14.067,0.952789,224,3.821,13.947,0.949345,219,3.957,13.797,0.945902,214,4.003,13.697,0.942558,214,1.163
```

Header Rows 1 and 2

The first two rows of the file store information about the location, and descriptive text that you can use for any purpose. SAM displays some of this information in the fields on the Wind Resource page. You can use the weather data viewer to examine the data in the file before running simulations.

Row 1

<location id>,<city>,<state>,<country>,<year>,<latitude>,<longitude>,<elevation>,<time step in hours>,<number of rows>

SAM displays the eight location-related values on the Wind Resource page, but does not use these values in calculations.

SAM uses the <timestep in hours> and <number of rows> to determine the data's temporal resolution, but does not use any of the other values in calculations. SAM requires hourly data, so the time step must be 1, and the number of rows must be 8760.

You must provide a value for each column: If you do not have a value for a column, you can use an indicator like *n/a* or *??* for the missing value.

SAM ignores the extra commas at the end of the row that your spreadsheet software may insert.

Note. SAM uses the air temperature and atmospheric pressure data for each time step to adjust the turbine power curve. It does not use the elevation above sea level for this purpose.

Row 2

<data source>

One line of descriptive text that SAM displays on the Wind Resource page. You may leave this line blank.

SAM ignores the extra commas at the end of the row that your spreadsheet software may insert.

Header Rows 3 - 5

Rows 3 and 4 tell SAM what data each column contains. SAM determines the type of data for each column based on the information in Rows 3 and 4. Rows 3 and 4 must have the same number of columns as the resource data rows 6 - 8765.

Row 3

The resource data type definition for each column of Rows 6 - 8765. Each column in Row 3 must contain one of the following text values (not case-sensitive) that corresponds to the resource data type in that column: *temperature*, *pressure*, *speed*, or *direction*. The resource data types do not have to be in any particular order, and can be in a different order for each hub height.

Row 3 must contain at least one column for each of the four data types. For a weather file with data at more than one height above the ground, Row 3 must contain a set of column definitions for each height.

Row 4

Measurement units for the resource data in each column corresponding to the resource data type in Row 3. Each column in Row 4 must contain a text value describing the measurement units. SAM displays this text in graphs and tables. For example: *atm*, *m/s*, *degrees*, *Celsius*, etc.

Note. SAM assumes that the resource data are in the units described below regardless of the values you specify in Row 4.

Row 5

Measurement height above the ground in meters for the resource data for each column defined in Row 3. Each column in Row 5 must contain an integer or decimal value.

Resource Data Rows 6 - 8765

The resource data rows store the wind speed, wind direction, air temperature, and atmospheric pressure values.

Row 6 should contain data for the hour ending at 1 am on January 1. (For time-dependent pricing calculations, SAM's financial models assume that January 1 is a Monday.)

The 8,760 resource data rows store integers or decimal values with the following units:

- Wind speed in meters per second (m/s).
- Wind direction in degrees east of north (degrees), with zero degrees indicating wind from the north, and 90 degrees indicating wind from the east.
- Atmospheric pressure in in atmospheres.
- Ambient temperature in degrees Celsius.

4.9 Location and Resource

The Location and Resource page allows you to choose a weather file describing the solar resource at the project location.

Notes.

You may want to model your system using weather data from several different sources and locations around your project site to understand both how sensitive your analysis results are to the weather assumptions, and how much variation there is in the data from the different weather files.

You can compare results for a system using more than one weather file in a single case by using SAM's parametric simulation option.

For a helpful discussion of weather data and power system simulation, see Stoffel T et al, 2010. Concentrating Solar Power Best Practices Handbook for the Collection and Use of Solar Resource Data. National Renewable Energy Laboratory NREL/TP-550-47465. http://www.nrel.gov/docs/fy10osti/47465.pdf.

Use the following guidelines to help you choose a weather file for your analysis.

For locations in the United States:

- Use the **Best weather data for the U.S.** web link at the bottom of the Location and Resource page to download a TMY3 file. If the TMY3 database does not include a file for a location at or very near your project site, try to find TMY3 files for locations near the site. You can run simulations for the different locations and compare them to get a sense of what the resource might be at the project site. See Download Weather Files for instructions.
- SAM comes with the complete set of the 239 TMY2 weather files. To use a TMY2 file, type a few letters of the file name (city or state), and choose the file from the Location list on the Location and Resource page. These files are in the *\weather* folder in your SAM installation folder (*c:\SAM\SAM 2014.1.14* by default in Windows).
- If no TMY3 or TMY2 data is available for your project site, and it is in the continental United States, you can use the Download Weather File feature to download files from NREL's Solar Power Prospector website.

For locations outside of the United States:

- Use the **Best weather data for international locations** web link on the Location and Resource page to download an EPW file, or purchase data from a commercial data provider. See Download Weather Files for instructions and more details.

To use your own weather data from a resource measurement program or from meteorological weather station:

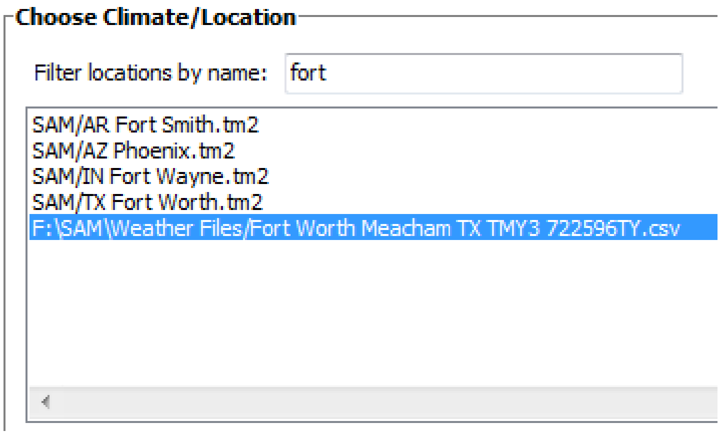
- Use SAM's TMY3 creator to create a TMY3 formatted file with the data.
- If you have sub-hourly weather data and are using the physical trough performance model, use the SMW weather file format.

Choosing the Weather File for your Analysis

To use a weather file that you download from the web, or a file that you created using the TMY3 creator or from another source, the file must be in your weather file folder.

To choose a weather data file from the Location list:

1. Download a weather file from the Internet.
2. Place the file in your weather file folder.
   Or, you can skip steps 1 and 2, and use one of the TMY2 files included with SAM.
3. Type a few characters of the weather file name in **Filter Locations by Name**.
4. Click the file name in the list to select it.



Choose Weather Data File

Filter locations by name

Type a few characters to search the contents of your weather file folders for a weather file.

The weather file list displays the current file with a blue highlight, and a list of other files in your weather file folders that match the search filter:

- File names preceded by "SAM/" are standard weather data files included with SAM and stored in the *\weather* folder of your SAM installation folder (*c:\SAM\SAM 2014.1.14* by default in Windows).
- File names preceded by "USER/" are weather files embedded in your SAM file.
- Weather files in your other weather file folder locations appear at the end of the list.

Note. The current weather file appears in the list regardless of whether it matches the search filter.

Download weather file

Type an address or coordinates for a U.S. location to download specific-year satellite-derived data from the Solar Prospector website. See Download Weather File for details.

Folder Settings

Manage the list of folders on your computer that SAM searches for weather data files, and set the default folder for weather data files that you download using the Download Weather File fature. SAM lists all weather files in folders that you add to the search list in the location list. See Weather File Folders for details.

Refresh List

Refreshes the list of files in the location list. SAM automatically refreshes the list each time you visit the weather data page. If you add a weather file to one of the folders in the search list, you may need to refresh the list for the file to be visible in the location list.

Copy to project

Embeds the data from a weather file to the project (*.zsam*) file. This useful when you share your project file with another person and do not want to send the weather file separately. Embedding weather data in a project increases the size of the project file. When you copy data to a project, SAM indicates the data with "USER/" in the location list. See Embed a Weather File for details.

Remove from project

Remove embedded weather data. The button is only active when the active location in the location list is preceded by "USER/."

Create TMY3 file

Use the TMY3 Creator to convert your own weather data into the TMY3 format. See Create TMY3 File for details.

Location Information

The location information variables display data from the weather file header that describes the location. An empty variable indicates that the information does not exist in the weather file's header. The location information variables cannot be edited.

Note. If the location information displays question marks ('??') instead of values, you must reload the weather file. This can happen when you open a SAM file that someone else created using a weather file that is either not on your computer, or not in one of the folders that you specified as a weather file folder.

To resolve this problem, you should either add a copy of the original weather file to your weather file folder, or choose a different weather file. See Manage Weather File Folders for details.

To avoid this problem in SAM files that you plan to share with other people, you can embed the weather file in your SAM. See Embed a Weather File.

City

The name of the city.

When you use Location Look up to download weather data, SAM displays "satellitedata" in the City field because the database does not provide a city name with the weather data.

State

The state abbreviation.

When you use Location Look up to download weather data, SAM displays "??" in the State field because the database does not provide a state name with the weather data.

Timezone

The location's time zone, relative to Greenwich Mean Time (GMT). A negative number indicates the number of time zones west of GMT. A positive number indicates the number of time zones east of GMT.

Elevation (m)

The location's elevation above sea level in meters.

Latitude (degrees)

The location's latitude in degrees. A positive number indicates a location north of the equator.

Longitude (degrees)

The location's longitude in degrees. A negative number indicates the number of degrees west of the Prime Meridian.

Weather Data Information (Annual)

SAM calculates and displays the annual totals and averages of four of the hourly data columns from the weather file in the weather data information variables. Weather data information variables cannot be edited.

Direct Normal (kWh/m2)

The sum of the 8,760 hourly values of the direct normal radiation data in the weather file, expressed in kWh per square meter. Direct normal radiation is solar energy that reaches the ground in a straight line from the sun.

To convert this number to kWh per square meter per day, divide it by 365 days/yr.

Global Horizontal (kWh/m2)

The sum of the 8,760 hourly values of the global horizontal radiation data in the weather file, expressed in kWh per square meter. The global horizontal radiation is the total amount of direct and diffuse solar radiation incident on a horizontal surface over the period of one year.

To convert this number to kWh per square meter per day, divide it by 365 days/yr.

Dry-bulb Temp (°C)

The annual average of the ambient temperature data in the weather file in degrees Celsius.

Wind Speed (m/s)

The annual average wind speed in meters per second.

For NREL TMY2 and TMY3 data, and EPW from the EnergyPlus website, wind speed data is at 10 meters above the ground.

View hourly data

Displays graphs of data from the weather file in SAM's built-in data viewer, DView. See Weather Data Viewer for details.

Web Links

Links to websites with weather files on the internet. Each link opens one of three website in your computer's default web browser. See Download Weather Files for details.

- **Best weather data for the U.S. (1200 + locations in TMY3 format)** takes you to NREL's National Solar Radiation Data Base (NSRDB) page for the Typical Meteorological Year 3 data.
- **Best weather data for international locations (in EPW format)** takes you to the EnergyPlus weather file page.
- **U.S. satellite-derived weather data (10 km grid cells in TMY2 format)** takes you to NREL's Solar Power Prospector website.

4.10 Wind Resource

The Wind Resource page allows you to choose weather data to use for your simulation with the Wind Power model.

Wind Resource by Location

The Wind Resource by Location option uses a wind resource file to describe the wind resource. The file contains hourly wind speed, direction, and temperature data at one or more heights above the ground, and an atmospheric pressure data value at a single height.

You can use this option to model a single wind turbine or a wind farm.

Note. If the turbine hub height on the Turbine page is not within 35 meters of either the lowest or highest wind data height in the wind data file, SAM displays an error message when you try to run simulations.

Wind Resource Characteristics

The Wind Resource Characteristics option uses an annual wind speed and Weibull K factor to describe the wind resource for a single turbine. SAM disables the inputs on the Wind Farm page with this option, so you can only model a single turbine.

Use this option for performance studies of different wind regimes, for example for a parametric analysis on annual average wind speed.

Wind Resource by Location

You can either choose a wind resource file from the list, or download a file from the internet:

- The wind resource files are stored in the file folder that you specify in the Folder Settings window.
- SAM's wind power model uses wind resource files in the SRW format. To use your own wind resource data, you can use the SRW format description to create a *.srw* file with your data.
- SAM comes with a set of typical data files for representative locations in the United States, which were developed for NREL by AWS Truepower. These files are appropriate for preliminary studies to explore the feasibility of potential projects, or for policy studies.
- For specific locations in the United States, you can download files from one of the NREL Wind Integration data sets using the Download Weather File feature.

Filter locations by name: Choose a wind resource file:

1. In the list of files, choose the name of the file. You can type a few letters of a location name to filter the list.

   The file may be one of the typical wind data files included with SAM, a wind data file you downloaded, or a file that you created with your own data.
2. Click **View Hourly Data** to examine the data and decide whether it is suitable for your analysis.

   The diurnal and seasonal distribution wind speeds and direction should be reasonably similar to the actual resource at the site under investigation. You can use the Time Series, Monthly Profile, and PDF/CDF graphs in the Weather Data Viewer to explore the data.

Download weather file: Download wind resource data for a location in the United States:

1. Click **Download Weather File**.
2. Type a latitude and longitude, street address, or zip code.

3. Click **OK**.

SAM displays information that describes the location represented by the data from the file for your information. This information is stored in the file header. SAM does not use any of this information or data in simulations.

Data Source

A text description of where the data in the file came from.

Latitude / Longitude

If you use the Download Weather File feature to download a file, this is the latitude and longitude of the location represented by the data. (It may differ from the latitude of the location you requested.)

If the wind data file does not have a value for the latitude and longitude, SAM displays "N/A."

Elevation

The location's height above sea level.

SAM does not use this value in calculations. It uses the temperature and atmospheric pressure data from the file to calculate the air density.

City / State

The city and state names stored in the file.

You can manage your wind data files using the following buttons:

Folder Settings

Add or remove a folder on your computer from the list of folders SAM searches for wind resource files. SAM lists all files in folders that you add to the search list in the location list. See Weather File Folders for details.

Refresh List

Refreshes the list of files in the location list. SAM automatically refreshes the list each time you visit the Wind Resource page. If you add a file to one of the folders in the search list, you may need to refresh the list for the file to be visible in the location list.

Copy to project

Embeds the data from a wind resource file to the project (*.zsam*) file. This is useful when you share your project file with another person and do not want to send the wind resource file separately. Embedding wind resource data in a project increases the size of the project file. When you copy data to a project, SAM indicates the data with "USER/" in the location list. See Embed a Weather File for details.

Remove from project

Remove embedded weather data. The button is only active when the active location in the location list is preceded by "USER/."

Wind Resource Characteristics

Define the wind resource using an annual wind speed and Weibull K factor. Use this option for wind turbine design studies when you want to examine the performance of a wind turbine under different wind resource regimes.

> **Note.** When you choose the **Wind Resource Characteristics** option, you can only model a project with a single wind turbine. SAM disables the inputs on the Wind Farm page because there is no data describing wind direction that SAM requires to model systems with more than one turbine.

Average Annual Wind Speed (@ 50 meters)

The average annual wind speed at the turbine location at 50 meters above the ground.

Weibull K Factor

The wind resource's Weibull K factor, describing the annual distribution of wind speeds at the turbine site.

Elevation Above Mean Sea Level

The height of the ground at the turbine site above mean sea level. This variable is active only when you choose the **Define turbine characteristics below** option on the Turbine page.

SAM displays a graph of probability distribution functions for of the wind resource that you specify. The graph shows the Weibull and Rayleigh probability distribution of the wind speed data, and the Weibull Betz probability distribution of energy over a range of wind speeds.

After running simulations, you can display tables of the 160 data bins on the Results page for the annual energy, hub efficiency, and turbine power curve values.

Representative Typical Wind Data Files

SAM comes with a set of representative typical wind resource files that are appropriate for very preliminary studies to explore the feasibility of potential projects, or for policy studies. The files were developed for NREL by AWS Truepower. Each file contains simulated hourly resource data and includes wind speed, wind direction, ambient temperature, and atmospheric pressure data at 50, 80, and 110 meters above the ground.

The files are for 39 representative locations, and use the following naming convention: *[State] [Region]-[Terrain Description].srw* to help you choose an appropriate file. For example, the file *AZ Eastern-Rolling Hills.srw* contains data appropriate for a location in eastern Arizona with rolling hills.

- *State* indicates where the data in the file was measured.
- *Region* is the part of the state where the data was measured.
- *Terrain Description* describes the type of terrain at the measurement site. See the table below for Google Earth images of the different terrain types.

Each file contains typical month data for a single year selected from the 14 years between 1997 and 2010. See Typical Year and Single Year Weather Data for a brief description of typical year data.

When you use one of these files, you should examine the data with SAM's Weather Data Viewer to make sure it is appropriate for your analysis. You may want to compare the data in the file to data from nearby meteorological stations or other data. Some things to look for are:

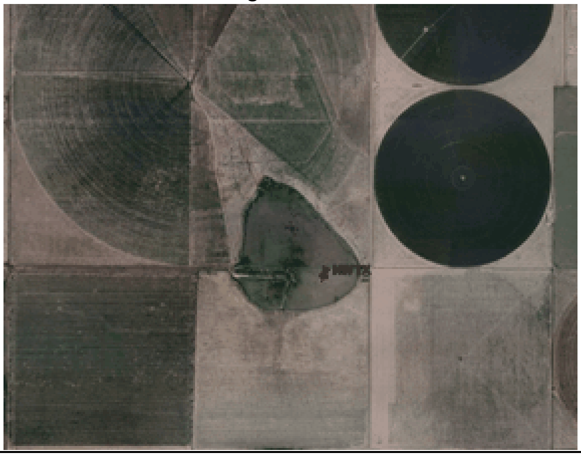
- The annual average wind speed is close to what you expect.
- The prevailing wind direction is similar to what you would expect at the site you are investigating. (This only matters if you are modeling a wind farm with more than one turbine.)
- The annual diurnal wind speed pattern is similar to what you would expect at the site.

Using data with similar terrain type as the site under investigation may help ensure that the wind shear profile (variation of the wind with height above the ground) of the data is reasonable for the site.

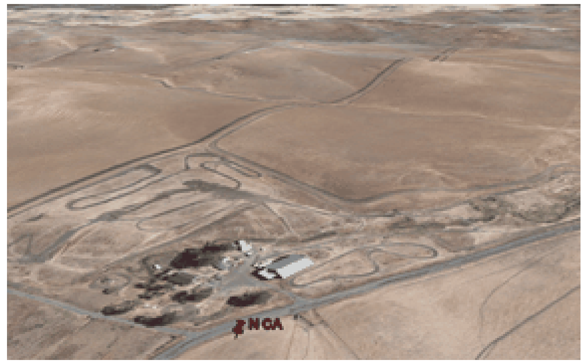
If you want to use one of the representative typical wind data files for a location that is not among the 39 representative locations, you can try to find a file with characteristics similar to those of your site.

You can use the images below to help choose a typical file with terrain characteristics similar to your site.

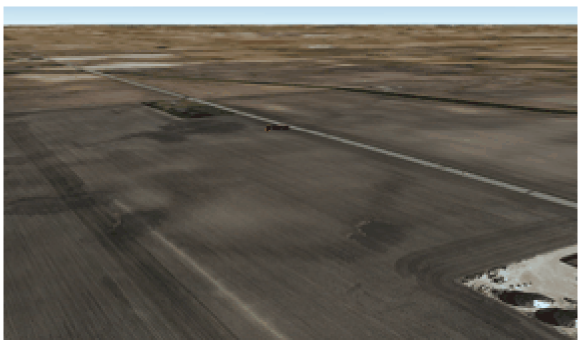
Agriculture



Barren/Prairie

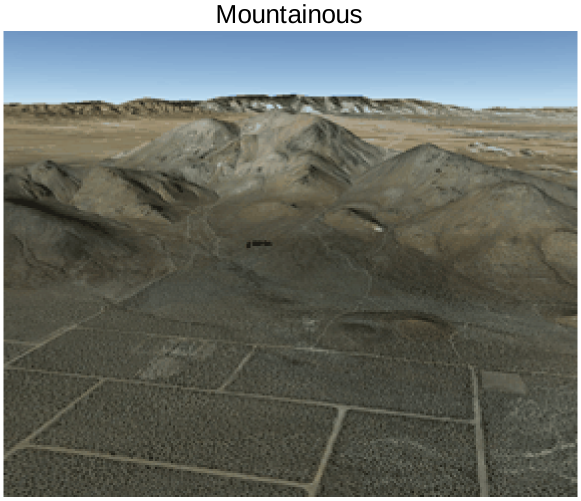


Flat Lands



Forest

Mountainous



Offshore

Rolling Hills

4.11 Location and Ambient Conditions

The Location and Ambient Conditions page allows you to choose a weather file to specify ambient conditions for the Steam Rankine Cycle for a biomass power system.

The biomass power model uses data from a weather file to describe ambient conditions for the Rankine steam cycle, and for modeling feedstock drying. It uses separate data set to describe the biomass resource (feedstock). The geographical coordinates in the weather file determines the location for the feedstock.

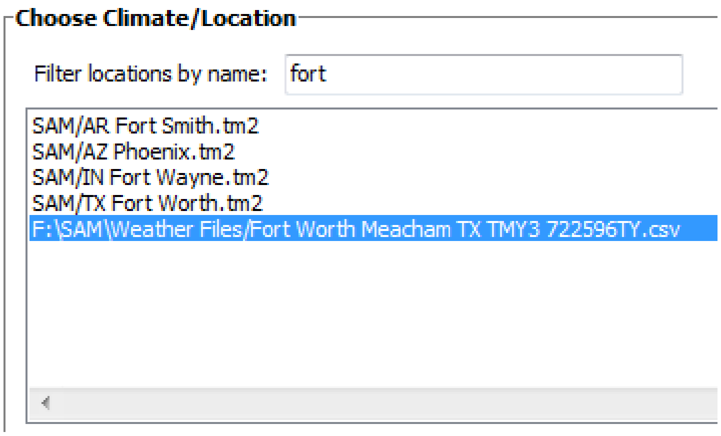
Ambient conditions also affect biomass composition, but on a monthly rather than hourly timescale. SAM calculates average monthly temperature, pressure, and humidity values from the hourly values in the weather file, and uses those values to represent the average ambient conditions for each month of the year. SAM uses the same set of twelve monthly average values for each year of the plant's life.

Choosing the Weather File for your Analysis

To use a weather file that you download from the web, or a file that you created using the TMY3 creator or from another source, the file must be in your weather file folder.

To choose a weather data file from the Location list:

1. Download a weather file from the Internet.
2. Place the file in your weather file folder.
   Or, you can skip steps 1 and 2, and use one of the TMY2 files included with SAM.
3. Type a few characters of the weather file name in **Filter Locations by Name**.
4. Click the file name in the list to select it.



Choose Weather Data File

Filter locations by name

Type a few characters to search the contents of your weather file folders for a weather file.

The weather file list displays the current file with a blue highlight, and a list of other files in your weather file folders that match the search filter:

- File names preceded by "SAM/" are standard weather data files included with SAM and stored in the *\weather* folder of your SAM installation folder (*c:\SAM\SAM 2014.1.14* by default in Windows).
- File names preceded by "USER/" are weather files embedded in your SAM file.
- Weather files in your other weather file folder locations appear at the end of the list.

Note. The current weather file appears in the list regardless of whether it matches the search filter.

Download weather file

Type an address or coordinates for a U.S. location to download specific-year satellite-derived data from the Solar Prospector website. See Download Weather File for details.

Folder Settings

Manage the list of folders on your computer that SAM searches for weather data files, and set the default folder for weather data files that you download using the Download Weather File fature. SAM lists all weather files in folders that you add to the search list in the location list. See Weather File Folders for details.

Refresh List

Refreshes the list of files in the location list. SAM automatically refreshes the list each time you visit the weather data page. If you add a weather file to one of the folders in the search list, you may need to refresh the list for the file to be visible in the location list.

Copy to project

Embeds the data from a weather file to the project (*.zsam*) file. This useful when you share your project file with another person and do not want to send the weather file separately. Embedding weather data in a project increases the size of the project file. When you copy data to a project, SAM indicates the data with "USER/" in the location list. See Embed a Weather File for details.

Remove from project

Remove embedded weather data. The button is only active when the active location in the location list is preceded by "USER/."

Create TMY3 file

Use the TMY3 Creator to convert your own weather data into the TMY3 format. See Create TMY3 File for details.

Location Information

The location information variables display data from the weather file header that describes the location. An empty variable indicates that the information does not exist in the weather file's header. The location information variables cannot be edited.

Note. If the location information displays question marks ('??') instead of values, you must reload the weather file. This can happen when you open a SAM file that someone else created using a weather file that is either not on your computer, or not in one of the folders that you specified as a weather file folder.

To resolve this problem, you should either add a copy of the original weather file to your weather file folder, or choose a different weather file. See Manage Weather File Folders for details.

To avoid this problem in SAM files that you plan to share with other people, you can embed the weather file in your SAM. See Embed a Weather File.

City

The name of the city.

When you use Location Look up to download weather data, SAM displays "satellitedata" in the City field because the database does not provide a city name with the weather data.

State

The state abbreviation.

When you use Location Look up to download weather data, SAM displays "??" in the State field because the database does not provide a state name with the weather data.

Timezone

The location's time zone, relative to Greenwich Mean Time (GMT). A negative number indicates the number of time zones west of GMT. A positive number indicates the number of time zones east of GMT.

Elevation (m)

The location's elevation above sea level in meters.

Latitude (degrees)

The location's latitude in degrees. A positive number indicates a location north of the equator.

Longitude (degrees)

The location's longitude in degrees. A negative number indicates the number of degrees west of the Prime Meridian.

Weather Data Information (Annual)

SAM calculates and displays the annual totals and averages of four of the hourly data columns from the weather file in the weather data information variables. Weather data information variables cannot be edited.

Direct Normal (kWh/m2)

The sum of the 8,760 hourly values of the direct normal radiation data in the weather file, expressed in kWh per square meter. Direct normal radiation is solar energy that reaches the ground in a straight line from the sun.

To convert this number to kWh per square meter per day, divide it by 365 days/yr.

Global Horizontal (kWh/m2)

The sum of the 8,760 hourly values of the global horizontal radiation data in the weather file, expressed in kWh per square meter. The global horizontal radiation is the total amount of direct and diffuse solar radiation incident on a horizontal surface over the period of one year.

To convert this number to kWh per square meter per day, divide it by 365 days/yr.

Dry-bulb Temp (°C)

The annual average of the ambient temperature data in the weather file in degrees Celsius.

Wind Speed (m/s)

The annual average wind speed in meters per second.

For NREL TMY2 and TMY3 data, and EPW from the EnergyPlus website, wind speed data is at 10 meters above the ground.

View hourly data

Displays graphs of data from the weather file in SAM's built-in data viewer, DView. See Weather Data Viewer for details.

Web Links

Links to websites with weather files on the internet. Each link opens one of three website in your computer's default web browser. See Download Weather Files for details.

- **Best weather data for the U.S. (1200 + locations in TMY3 format)** takes you to NREL's National Solar Radiation Data Base (NSRDB) page for the Typical Meteorological Year 3 data.
- **Best weather data for international locations (in EPW format)** takes you to the EnergyPlus weather file page.
- **U.S. satellite-derived weather data (10 km grid cells in TMY2 format)** takes you to NREL's Solar Power Prospector website.

4.12 Ambient Conditions

The Ambient Conditions page allows you to choose a weather file to specify ambient conditions for the geothermal system's power block model when you specify either **Power Block Monthly** or **Power Block Hourly** as the Model option on the Power Block page.

The geothermal resource is specified on the Resource page.

> **Important Note!** You do not need to specify a weather file with the GETEM power block option. With the GETEM power block option, SAM ignores the weather file you choose on the Ambient Conditions page.

The geothermal performance model runs simulations over the life of the plant (defined by **Analysis Period** on the Financing page) in order to account for the annual decline in resource temperature. SAM assumes that the data in the weather file represents typical ambient conditions at the power block over the entire analysis period. Because the weather file contains data for a single year, SAM reads data from the weather file multiple times to complete the multi-year simulation:

- For hourly simulations (**Power Block Hourly** option on the Power Block page), SAM reads hourly data from the weather file, and uses it to represent ambient conditions in each hour for each year of the analysis period. For example, for an analysis period of 30 years, SAM would use the same temperature, pressure, and humidity values for each July 2nd at 2 pm for each of the 30 years.
- For monthly simulations (**Power Block Monthly** option on the Power Block page), SAM calculates average temperature, pressure, and humidity values from the hourly values in the weather file, and uses them to represent the average ambient conditions for each month of the year. SAM uses the same set of twelve monthly average values for each year of the plant's life.

Choosing the Weather File for your Analysis

To use a weather file that you download from the web, or a file that you created using the TMY3 creator or another source, the file must be in your weather file folder.

To choose a weather data file from the Location list:

1. Download a weather file from the Internet.
2. Place the file in your weather file folder.

   Or, you can skip steps 1 and 2, and use one of the TMY2 files included with SAM.
3. Type a few characters of the weather file name in **Filter Locations by Name**.
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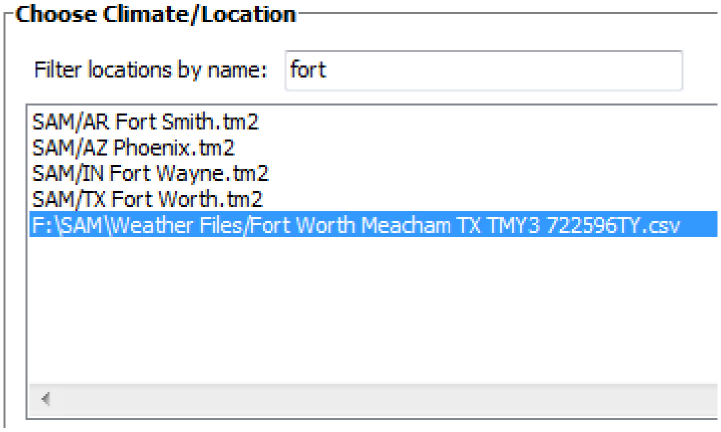

Choose Weather Data File

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Type an address or coordinates for a U.S. location to download specific-year satellite-derived data from the Solar Prospector website. See Download Weather File for details.

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Manage the list of folders on your computer that SAM searches for weather data files, and set the default folder for weather data files that you download using the Download Weather File fature. SAM lists all weather files in folders that you add to the search list in the location list. See Weather File Folders for details.

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Remove from project

Remove embedded weather data. The button is only active when the active location in the location list is preceded by "USER/."

Create TMY3 file

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Location Information

The location information variables display data from the weather file header that describes the location. An empty variable indicates that the information does not exist in the weather file's header. The location information variables cannot be edited.

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The location's time zone, relative to Greenwich Mean Time (GMT). A negative number indicates the number of time zones west of GMT. A positive number indicates the number of time zones east of GMT.

Elevation (m)

The location's elevation above sea level in meters.

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Weather Data Information (Annual)

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Direct Normal (kWh/m2)

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Dry-bulb Temp (°C)

The annual average of the ambient temperature data in the weather file in degrees Celsius.

Wind Speed (m/s)

The annual average wind speed in meters per second.

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View hourly data

Displays graphs of data from the weather file in SAM's built-in data viewer, DView. See Weather Data Viewer for details.

Web Links

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- **Best weather data for international locations (in EPW format)** takes you to the EnergyPlus weather file page.
- **U.S. satellite-derived weather data (10 km grid cells in TMY2 format)** takes you to NREL's Solar Power Prospector website.

5 Performance Models

Each energy technology in SAM has a corresponding performance model that performs calculations specific to the technology. Most of the performance models are hourly simulation models that calculate the total annual electric output of the system, which is then used by the financial model to calculate the project cash flow and financial metrics.

Notes.

The solar water heating models calculate the thermal output of the system, assuming that it displaces electricity that would normally heat water in a conventional water heating system.

Because of the nature of the technology, the geothermal model calculates system performance over a period of years rather than hours.

SAM can perform sub-hourly simulations for advanced analyses, but relies on interpolation to determine the solar resource based on hourly weather data.

Photovoltaic Systems

SAM models grid-connected photovoltaic systems that consist of a photovoltaic array and inverter. The array can be made up of flat-plate or concentrating photovoltaic (CPV) modules with one-axis, two-axis, or no tracking.

Flat Plate PV

The Flat Plate PV option represents the performance of a photovoltaic system using separate models to represent the performance of the module and inverter. This is in contrast with the PVWatts System Model, which represents the entire system using a single model.

This option allows you to choose between the Sandia, CEC, and simple efficiency models for photovoltaic modules, and between the Sandia and single-point efficiency models for inverters.

High-X Concentrating PV

The High-X Concentrating PV option (HCPV) is appropriate for concentrating photovoltaic systems. Like the flat plate model, the HCPV model uses separate models to represent the module and inverter.

PVWatts System Model

The PVWatts System Model represents the entire photovoltaic system using a single model. This is in contrast with the Flat Plate PV option, which uses separate models to represent the performance of the module and inverter.

Concentrating Solar Power

Parabolic Trough (Physical Model)

The physical trough model calculates the electricity delivered to the grid by a parabolic trough solar field that delivers thermal energy to a power block for electricity generation, with an optional thermal energy storage system. The physical trough model characterizes many of the system components from first principles of heat transfer and thermodynamics, rather than from empirical measurements as in the empirical trough system model. While the physical model is more flexible than the empirical model (see below), it adds more uncertainty to performance predictions than the empirical model.

Parabolic Trough (Empirical Model)

The empirical trough model models the same type of parabolic trough system as the physical trough model, but uses a set of curve-fit equations derived from regression analysis of data measured from the SEGS projects in the southwestern United States, so you are limited to modeling systems composed of components for which there is measured data. The model is based on Excelergy, originally developed for internal use at at the National Renewable Energy Laboratory.

Molten Salt Power Tower

A molten salt power tower system (also called central receiver system) consists of a heliostat field, tower and receiver, power block, and optional storage system. The field of flat, sun-tracking mirrors called heliostats focus direct normal solar radiation onto a receiver at the top of the tower, where a molten salt is heated and pumped to the power block. The power block generates steam that drives a conventional steam turbine and generator to convert the thermal energy to electricity.

Direct Steam Power Tower

The direct steam power tower model is for a system that uses steam in the receiver instead of a salt heat transfer fluid.

Linear Fresnel

A linear Fresnel system consists of a field of slightly curved or flat Fresnel reflectors that focus light on an absorber in the focal plane above the reflector. The absorber circulates a heat transfer fluid that transfers heat to a power block. The system may include thermal storage.

Dish Stirling

A dish-Stirling system consists of a parabolic dish-shaped collector, receiver and Stirling engine. The collector focuses direct normal solar radiation on the receiver, which transfers heat to the engine's working fluid. The engine in turn drives an electric generator. A dish-Stirling power plant can consist of a single dish or a field of dishes.

Generic Solar System

The generic solar system model allows you to model a system that consists of a solar field, power block with a conventional steam turbine, and optional thermal energy storage system. The model represents the solar field using a set of optical efficiency values for different sun angles and can be used for any solar technology that uses solar energy to generate steam for electric power generation.

Generic System

The generic system model is a basic representation of a conventional power plant. The Generic technology option makes it possible to compare analyses of renewable energy project to a base case conventional plant using consistent financial assumptions.

The generic system model allows you to characterize the plant's performance either using one of two options:

- Specify a nameplate capacity and capacity factor value: Assumes that the plant generates power at a constant rate over the year.
- Specify an hourly our sub-hourly generation profile: Assumes that the plant generates power according to the generation profile you specify.

Solar Water Heating

SAM's Solar Water Heating model represents a two-tank glycol system with an auxiliary electric heater and storage tank for residential or commercial applications. The model allows you to vary the location, hot water load profiles, and characteristics of the collector, heat exchanger, and solar tanks.

Wind Power

Wind Power

The wind power model can model a single small or large wind turbine, or a project with two or more large or small wind turbines that sells power to the grid.

> **Note.** The Wind Power model combines the small-scale and utility-scale wind turbine models in previous versions.

Geothermal

> **Note.** SAM's geothermal models are for electricity generation systems, not ground source heat pumps or geoexchange systems.

Geothermal Power

A geothermal power plant uses heat from below the surface of the ground to drive a steam electric power generation plant. SAM analyzes the plant's performance over its lifetime, assuming that changes in the resource and electrical output occur monthly over a period of years, rather than over hours over a period of one year as in the solar and other technologies modeled by SAM.

Geothermal Co-Production

The co-production model is for relatively small commercial-scale projects that generate electricity from a geothermal resource available at the site of an oil or gas well.

Biomass Power

A biomass power system burns a biomass feedstock (with or without supplementary coal) in a combustion system to generate electricity.

6 Photovoltaic Systems

A photovoltaic system converts light from the sun into electricity. SAM models grid-connected photovoltaic systems that consist of a photovoltaic array and inverters. The array can be made up of flat-plate or concentrating photovoltaic (CPV) modules.

Note. The current version of SAM does not model off-grid photovoltaic systems, or photovoltaic systems with storage.

SAM includes three photovoltaic system performance models:

- Flat Plate PV models the system using separate sub-models for the module and inverter components of the system.
- High-X Concentrating PV models concentrating PV (CPV) systems.
- PVWatts System Model uses a simple set of inputs to model a crystalline silicon based system, and is an implementation of NREL's web-based PVWatts model.

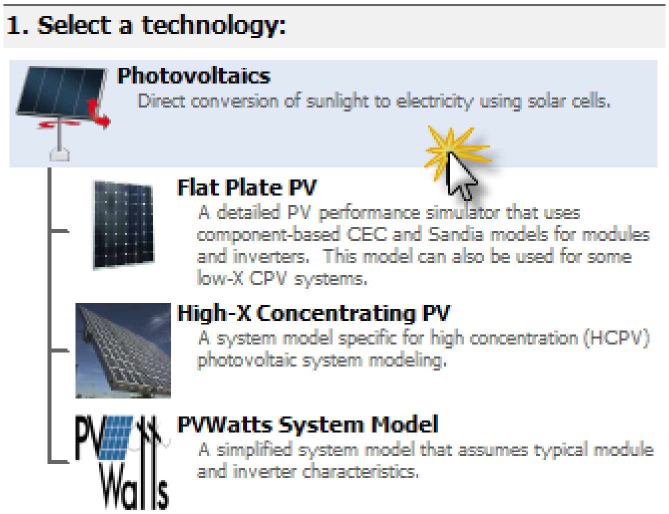
For step-by-step instructions on using the photovoltaic models, see Getting Started with PV.

6.1 Getting Started with PV

The procedure below describes the basic steps to get started modeling a project based on photovoltaic technology. For general getting started topics, see Getting Started.

1. Choose a performance model

When you create a new file or case, SAM offers three options for modeling PV systems: Flat Plate PV, High-X Concentrating PV, and PVWatts System Model.



Flat Plate PV

Choose Flat Plate PV when you have a specific manufacturer and model number in mind for the module and inverter.

The Flat Plate PV model represents the performance of a photovoltaic system using separate models to represent the performance of the module and inverter. You specify the module and inverter characteristics, array layout, pre-inverter and interconnection derating factors, and optional shading, temperature correction, and backtracking parameters. The Flat Plate PV model calculates and reports detailed results, including the array's DC output, system's AC output, cell temperature, and the hourly efficiency of the array and inverters.

Use the Flat Plate PV model to model crystalline or thin-film modules, and for arrays with open rack, flush, gap, or building-integrated mounting.

The Flat Plate PV model allows you to choose between the Sandia, CEC, and single-point efficiency models for photovoltaic modules, and between the Sandia and single-point efficiency models for inverters.

High-X Concentrating PV

Choose High-X Concentrating PV to model concentrating PV (CPV) systems.

PVWatts System Model

Choose PVWatts when you want quick results for a PV system with crystalline silicon modules.

The PVWatts System Model represents the entire photovoltaic system using a single derate factor and accounts for the effects of temperature on the system's performance. The PVWatts model is appropriate for modeling rack-mounted systems with crystalline silicon modules. The PVWatts model calculates and reports the array DC output, system AC output (based on a fixed derate factor), and cell temperature.

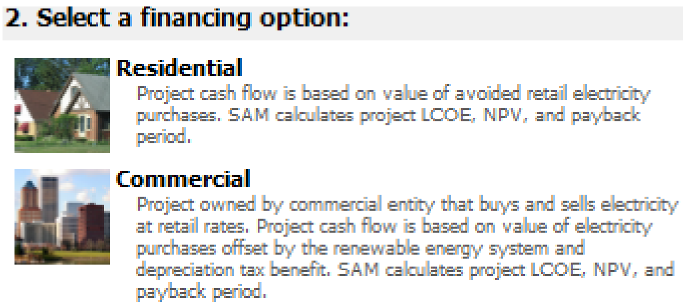
The following table summarizes the three PV modeling options:

	Flat Plate PV	PVWatts System Model	High-X Concentrating PV
Array output (DC)	•	•	•
Inverter output (AC)	•	•	•
Temperature effects	•	•	•

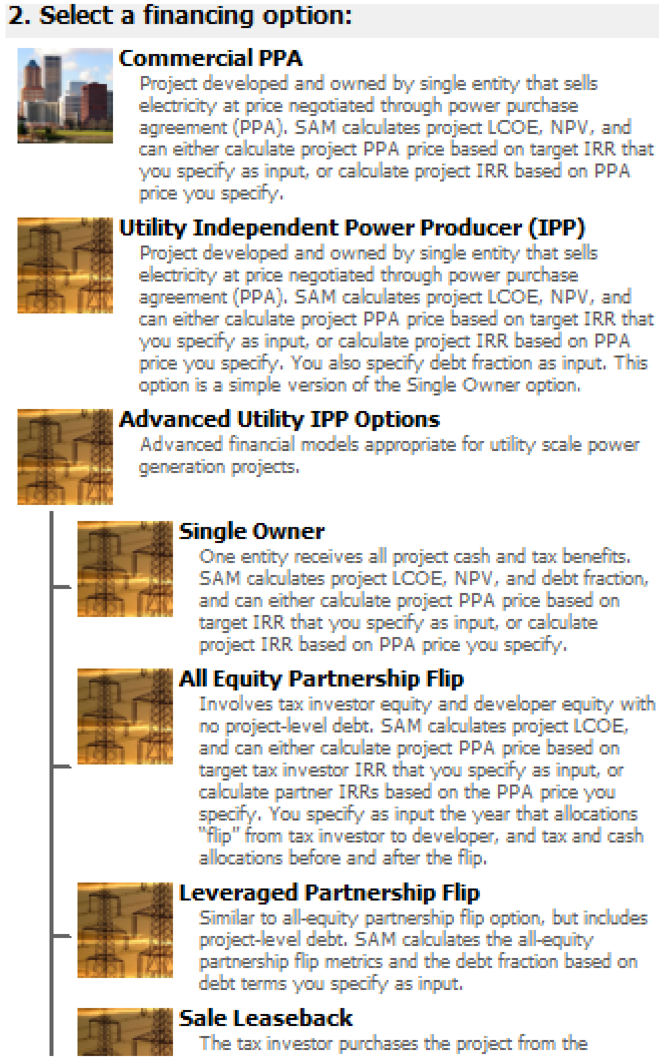
Array shading	•	•	•
Tracking options	•	•	
Row-to-row shading	•		
Backtracking	•		
Mounting options	•		
Multiple subarrays	•		

2. Choose a financing option

For projects that buy and sell power at retail rates and displace a building or facility electric load, choose Residential or Commercial:



For projects that sell all of the power the system generates at a price determined in a power purchase agreement (PPA), choose Commercial PPA, Utility Independent Power Producer (IPP), or one of the Advanced Utility IPP options (click **Advanced Utility IPP Options** to expand or collapse the list):



Note. SAM does not impose a size limit based on the financing option you choose. You can use any financing option with any size of system.

For a project on the customer side of a utility meter that buys and sells power at retail rates, choose either Residential or Commercial financing:

- Commercial allows you to model depreciation as a tax deduction (MACRS or custom).
- Residential allows you to choose between a standard loan in which interest payments are not tax deductible, and mortgage, in which interest payments are tax deductible.

For a power generation project that sells electricity at a negotiated price, choose either Commercial PPA or one of the Utility Market options:

- Commercial PPA calculates a power purchase price (PPA price) based on a target internal rate of return (IRR) that you specify. You can either specify a debt fraction and annual PPA price escalation rate, or allow SAM to find optimal values.
- The Utility Market Options allow you to either specify a target IRR (SAM calculates a PPA price), or specify a PPA price (SAM calculates the IRR). The Independent Power Producer option is similar to

Commercial PPA, but allows you to add constraints for minimum debt-service coverage ratio (DSCR) and positive cash flow. The other Utility Market options allow you to model projects with a single owner, or with two parties with different structures for sharing project costs and revenues.

Note. The Commercial PPA and Utility Independent Power Producer financing options are legacy options to allow you to model projects consistently with older versions of SAM. The partnership flip, sale leaseback, and single owner options are more representative of actual financing structures for renewable energy projects.

See Financing Overview for details.

3. On the Location and Resource page, choose a weather file to represent the solar resource at the project location

SAM offers four weather data options. You can:

- Choose a location from the list at or near your project site. SAM will simulate the system using a file from NREL's TMY2 database.
- Download a weather file for your site from an online database. SAM will simulate the system using a file from NREL's database of satellite-derived solar resource data.
- Download a file from NREL's TMY3 database.
- Create a weather file in TMY3 format with your own data

For preliminary analyses in the United States either use a TMY2 file if there is a file in the database with similar weather to the project site, or download a file for the location.

For more robust analysis, download TMY3 data, or use your own data. You may also want to analyze your project using weather data from different sources to develop an understanding of how uncertainty in the weather data affects the metrics of interest for your project.

See Location and Resource for details.

4. Specify the system's characteristics

For the Flat Plate PV model

1. On the Inverter page, choose a model option and inverter.
2. On the Module page, choose a model option and module.
3. On the Array page, specify the system's size. See Sizing the PV System for sizing instructions.
4. On the PV Subarrays page, specify the array orientation.

For the HCPV model

1. On the Inverter page, choose an inverter.
2. On the Module page, specify the CPV module parameters.
3. On the Array page, specify the system's size and other parameters.

For the PVWatts System model

1. On the PVWatts Solar Array page, enter the system's DC nameplate capacity for **Nameplate Capacity**.
2. Choose a tracking option and specify the tilt angle.

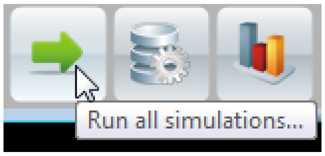
5. On the PV System Costs page, specify the project costs

The capital costs (direct and indirect) are construction and installation costs that SAM applies to year zero of the cash flow.

The operation and maintenance costs apply in years one and later of the cash flow.

See PV System Costs for details.

6. Run a simulation and review results



See Results Page for details.

6.2 Shading

SAM models two types of shading for photovoltaic systems:

- Array shading affects the entire subarray (Flat Plate PV) or array (PVWatts) uniformly. SAM models array shading as a set of hourly shading factors that reduce the solar radiation incident on the array. The Flat Plate PV, PVWatts, and HCPV models each include a version of the array shading model.
- Self shading where neighboring modules within the array shade each other. SAM models self shading as a set of DC derate factors that reduce the array's DC output. Self shading only works with the Flat Plate PV model for systems with one PV subarray and fixed tracking.

For the Flat Plate PV and PVWatts models, you can also import shading files created by PVSyst, Solmetric Suneye, or Solar Pathfinder software. When you import these files, SAM converts the data they contain to shading factors for the array shading model.

Notes.

For the Flat Plate PV and HCPV models, the monthly soiling derate factors also reduce the radiation incident on the array.

For the Flat Plate PV model, the self-shading model only works when the model option on the Module page is either **CEC Performance Model** or **Sandia PV Array Performance Model**. If the **Simple Efficiency Module** option is active, the self-shading parameters on the Array page have no effect on simulation results.

If you use the PVWatts array shading model, be sure to choose a DC to AC derate factor on the PVWatts Solar Array page that does not include the effect of shading.

Array Shading

The array shading model calculates the effect of a reduction of the solar radiation incident on the array due to shadows on the array created by nearby objects such as trees and buildings.

The array shading model assumes that the entire array is uniformly shaded.

Array Shading in Results

To see the effect of shading factors on the radiation incident on the array, after running simulations, you can compare values in the hourly Tables on the Results page for nominal beam and diffuse, and incident beam and diffuse radiation. The "nominal" values are radiation values before SAM applies the shading and soiling factors, and the "incident" values are net radiation values SAM assumes is incident on the array.

Enabling and Disabling Array Shading

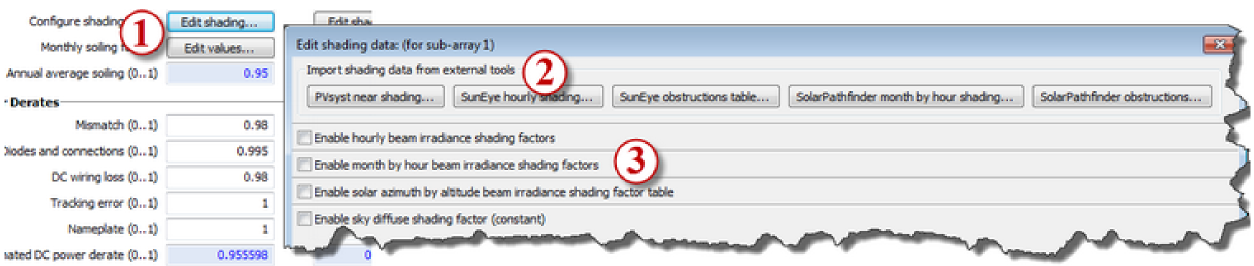
The Flat Plate PV and PVWatts models provide five options for importing shading data files, three options for specifying beam shading factors, and one option for specifying a sky diffuse factor.

- You must choose at least one option.
- SAM does not prevent you from enabling more than one option even if that results in an unrealistic shading model. Be sure to verify that you have enabled the set of options you intend before running simulations.

The HCPV model provides a single option to specify beam shading factors in an Azimuth by Altitude table. See Azimuth by Altitude for details.

To enable the array shading model for the Flat Plate PV or PVWatts model:

1. Click **Edit Shading.** The location of the Edit Shading button depends on the PV model:
   - Flat Plate PV: PV Subarrays page. You can specify different shading factors for each subarray.
   - PVWatts: PVWatts Solar Array page.
2. If you are working with a shading file from PVsyst, Solmetric Suneye, or Solar Pathfinder software, click the appropriate button under **Import shading data from external tools** to import the file. See Import Shading Files for details.
3. If you are using a table to specify shading factors (you can type, import, or paste values into the table), check the appropriate **Enable** box. Checking each box causes a table to expand. See Beam Radiation Factors for details.



Beam and Sky Diffuse Shading Factors

Each shading factor is a value between zero and one that represents the fraction of the solar radiation component (either beam or diffuse) allowed to reach the array. A shading factor of one represents no shading. A shading factor of zero represents complete blockage of either the beam or sky diffuse radiation from the array.

The value of the shading factor in each hour depends on the method you use to specify the values.

To calculate the effect of shading on the array, SAM adjusts the incident beam and diffuse radiation value that it calculates from the data in the weather file and solar angles in each hour as appropriate:

- SAM multiplies the incident normal radiation in each hour by the beam shading factor for that hour. The incident normal radiation is the solar radiation that reaches the array in a straight line from the sun.

  For example, for a beam shading factor of 0.90 for the 8 a.m. hour of December 20, SAM would multiply the beam radiation value in the weather file by 0.90 for that hour, and use that derated value to calculate the total incident radiation on the array for that hour.
- SAM multiplies the incident sky diffuse radiation for each hour by the sky diffuse shading factor. Sky diffuse radiation is radiation that reaches the array from the sun indirectly after being reflected by clouds and particles in the atmosphere. Sky diffuse radiation does not include diffuse radiation reflected from the ground. Note that you can only specify a single value that applies to all hours of the year for the sky diffuse shading factor.

Beam Radiation Shading Factors

The Flat Plate PV and PVWatts models provide three options for specifying beam shading factors: Hourly 8760, Month by Hour, and Solar Azimuth by Altitude angle. The HCPV model provides only the Solar Azimuth by Altitude option.

Typically, you would enable only one of the three options. However, if you enable more than one option, SAM multiplies the shading factors you enabled for each hour to calculate a total shading factor.

Tip. If you plan to import hourly, month-by-hour, or azimuth-by-altitude shading data from text files, you can see the correct file format by exporting dummy data. SAM will create a text file in the correct format that you can use as an example for your data.

Hourly 8760

The Hourly 8760 option allows you to use a set of hourly (8,760 hours/year) beam shading factors for the project location.

The data's time convention should follow that of the weather file. For the standard TMY files, Hour 1 is the hour ending at 1 a.m. on Monday, January 1.

To specify hourly beam shading factors:

1. Click **Edit shading** on the PV Subarrays page or PVWatts Solar Array page to open the Edit Shading Data window.
2. Check **Enable hourly beam irradiance shading factors**.
3. Click **Edit Data**.
4. To copy data from a spreadsheet, select and copy a column of 8,760 beam shading factors in the spreadsheet and click **Paste** in the Edit Data window.

   To import data from a text file, click **Import** and navigate to the file. The file must contain a single column of 8,761 rows: A header in the first row followed by 8,760 beam radiation values.

   To see an example of the correct file format, click **Export** to export the default shading table to a text file and open it with a text editor.

Month by Hour

To specify month by hour shading factors:

1. Click **Edit shading** on the PV Subarrays page or PVWatts Solar Array page to open the Edit Shading Data window.
2. Check **Enable month by hour beam irradiance shading factors**.

To the month-by-hour shading factor matrix is a 24-by-12 table containing a set of 24 hourly shading factors for each month of the year. The shading factor in a cell applies to a given hour for an entire month.

- The data's time convention should follow that of the weather file. For the standard TMY files, the value in the first row and column is for the hour ending at 1 a.m. for all days in January.
- A red cell indicates a value of zero, or full shading (beam radiation completely blocked).
- A white cell indicates a value of one, or no shading.
- A dark shade of red indicates more shading (more beam radiation) than a light shade of red.

To define a shading factor for a single cell:

- Click the cell and type the shading factor.
- To replace the value in a cell, click the cell and type a replacement value.
- To delete the value from a cell, double-click the cell and press the Delete key.

To define a single shading factor for multiple cells:

- Use your mouse to select the cells to which you want to apply the shading factor.
- Type a value between zero and one.
- Press the Enter key or click **Apply to selected cells**.

To import or export month-by-hour beam shading factors:

Solar Advisor allows you to import and export the shading factor matrix as a comma-delimited text file that contains 12 rows of 24 hourly shading factors separated by commas. The file should not have row or column headings.

To see an example of the correct file format, export the default shading table to a text file and open it with a text editor.

- To export the shading matrix as a text file, click **Export**. SAM saves the file with the *.csv* extension.
- To import a data from a comma-delimited text file, click **Import**. You can open a correctly formatted text file with any extension, although SAM expects a *.csv* file by default.

Solar Azimuth by Altitude

The solar azimuth-by-altitude table is a two-dimensional look-up table of beam irradiance shading factors. For each hour in the simulation, SAM calculates the position of the sun as a set of solar azimuth and altitude angles and looks up the shading factor to use for that hour based on the solar position. SAM uses linear interpolation to estimate the value of the shading factor for solar angles that fall between values in the table row and column headings.

> **Important Note:** Azimuth values use the following convention: 0 = north, 90 = east, 180 = south, 270 = west.
>
> This differs from the convention in older versions of SAM. If you use the current version of SAM to open a file you saved with an older version, SAM should correctly convert the column heading values, but you should check the values before running simulations.

To define the azimuth-altitude shading factor table by hand:

1. Click **Edit shading** on the PV Subarrays page or PVWatts Solar Array page to open the Edit Shading Data window.
2. Click **Enable solar azimuth by altitude beam irradiance shading factor table**.
3. In **Rows** and **Cols**, type the number of rows and columns in the table.

   Specify a number of rows that is one greater than the number of azimuth values: For example for a table with ten rows of solar azimuth values, specify a **Rows** value of 11. Similarly, specify a **Cols** value that is one greater than the number of altitude values.
4. In the top row (highlighted in blue), type a set of solar azimuth values between zero and 360 and increasing monotonically from left to right.
5. In the leftmost column (highlighted in blue), type a set of solar altitude between zero and 90 and increasing monotonically from top to bottom.
6. Type a beam shading factor value (between zero and one) in each cell of the table. A value of zero indicates that beam irradiance is fully blocked by a shading object. A value of one indicates that beam irradiance is not blocked.

To import or export azimuth-by-altitude beam shading factors:

SAM allows you to import and export the azimuth-altitude lookup table as a comma-delimited text file that contains shading factors separated by commas. The file should include the row and column headings.

To see an example of the correct file format, export the default shading table to a text file and open it with a text editor.

- To export the shading matrix as a text file, click **Export.** You can save the file with any file extension, including *.txt* or *.csv*.
- To import data from a comma-delimited text file, click **Import**.

Sky Diffuse Shading Factor

A shading factor for sky diffuse radiation may be used. This factor is applied to every hour in the year. This value is considered to be the fraction of the sky that is obstructed, and is therefore constant.

To define a sky diffuse shading factor:

1. Click **Edit shading** on the PV Subarrays page or PVWatts Solar Array page to open the Edit Shading Data window.
2. Click **Enable sky diffuse shading factor (constant)**.
3. Type a value for the shading factor.

Import Shading Files

SAM allows you to import shading data from the following software:

- PVsyst, photovoltaic system design software, http://www.pvsyst.com
- Solmetric SunEye, shading analysis device, http://www.solmetric.com
- Solar Pathfinder, shading analysis device, http://www.solarpathfinder.com

Importing Data from PVsyst

You can import a "Near Shadings" table generated by PVsyst into SAM. SAM automatically imports data from the text file generated by PVsyst into the Solar Azimuth by Altitude Shading Factor table and the diffuse shading factor value.

Notes. We have tested the following procedure with Version 5 of PVsyst.

The "Near Shadings" table in PVsyst looks like this:

Project SAM_Example_Project.PRJ, New shading scene

Close Print Export Help

Shading factor table (linear), for the beam component

Azimuth / Height	-180°	-160°	-140°	-120°	-100°	-80°	-60°	-40°	-20°	0°	20°	40°	60°	80°	100°	120°	140°	160°	180°
90°	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
80°	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
70°	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
60°	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.989	0.984	0.989	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
50°	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.978	0.958	0.952	0.958	0.978	1.000	1.000	1.000	1.000	1.000	1.000	1.000
40°	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.977	0.924	0.917	0.924	0.977	1.000	1.000	1.000	1.000	1.000	1.000	1.000
30°	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.977	0.900	0.900	0.900	0.977	1.000	1.000	1.000	1.000	1.000	1.000	1.000
20°	Behind	1.000	1.000	1.000	1.000	1.000	1.000	0.977	0.900	0.900	0.900	0.977	1.000	1.000	1.000	1.000	1.000	1.000	Behind
10°	Behind	Behind	Behind	1.000	1.000	1.000	1.000	0.977	0.900	0.900	0.900	0.977	1.000	1.000	1.000	1.000	Behind	Behind	Behind
2°	Behind	Behind	Behind	Behind	1.000	1.000	1.000	0.977	0.900	0.900	0.900	0.977	1.000	1.000	1.000	Behind	Behind	Behind	Behind

Shading factor for diffuse: 0.977 and for albedo: 0.935

The "Near Shadings" data exported to a text file looks like this (in this example with semicolon delimiters):

```
Shading factor table (linear), for the beam component;
Azimuth;-180°;-160°;-140°;-120°;-100°; -80°; -60°; -40°; -20°;   0°;  20°;  40°;  60°;  80°; 100°; 120°; 140°; 160°; 180°;
Height;
 90°;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;
 80°;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;
 70°;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;
 60°;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;
 50°;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;0.997;0.991;0.999;1.000;1.000;1.000;1.000;
 40°;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;0.989;0.961;0.962;0.988;1.000;1.000;1.000;1.000;
 30°;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;1.000;0.932;0.898;0.914;0.975;0.999;1.000;1.000;1.000;
 20°;1.000;1.000;1.000;1.000;Behind;Behind;1.000;1.000;1.000;1.000;0.922;0.823;0.808;0.849;0.959;0.999;1.000;1.000;1.000;
 10°;1.000;1.000;Behind;Behind;Behind;Behind;Behind;Behind;1.000;1.000;0.819;0.629;0.698;0.780;0.938;0.999;1.000;1.000;1.000;
  2°;1.000;Behind;Behind;Behind;Behind;Behind;Behind;Behind;Behind;1.000;0.783;0.502;0.639;0.754;0.921;0.999;1.000;1.000;1.000;
Shading factor for diffuse:  0.968  and for albedo:  0.820;
```

To import a "Near Shadings" table from PVsyst:

1. In PVsyst, follow the procedure to create and export a "Near Shadings" table. The table in PVsyst should look similar to the one below. SAM will recognize any of the delimiter options: tab, comma, or semicolon.
2. In SAM, click **Edit shading** (on the PV Subarrays page or PVWatts Solar Array page) to open the Edit Shading Data window, and click the **PVsyst near shading** and navigate to the folder containing the shading file.

When SAM imports data from the file, it displays the message "Azimuth-Altitude Table and Diffuse Factor update" and populates the azimuth-altitude shading table, the sky diffuse shading factor, and enables both options.

3. Disable any shading options that do not apply to your analysis.

Importing from Solmetric SunEye

The Solmetric SunEye software generates shading data in two formats: The obstruction table, which characterizes shading using an altitude-azimuth angle table to indicate solar positions that are blocked by nearby obstructions, and the hourly shading file, which lists hourly beam radiation shading factors. SAM can read data from both tables.

Use the obstruction table if you plan to model the system for different locations (assuming the same shading obstructions). Use the hourly shading factor table if you plan to model the system for a single location.

> **Note.** If you use the hourly shading factor table, be sure that the weather data specified on the Location and Resource page is for the same location as the one where the SunEye measurements were made.

To import a SunEye obstruction table:

1. In the Solmetric SunEye software (not the PV Designer software), on the **File** menu, click **Export Session Report and Data**.

   The SunEye software creates a set of files, and assigns a default name like *Sky01ObstructionElevations.csv* to the obstruction data file. By default, the files are in a folder named *ExportedFiles* in the exported report folder.
2. In SAM, click **Edit shading** (on the PV Subarrays page or PVWatts Solar Array page) to open the Edit Shading Data window, and click **Suneye obstructions table**, and navigate to the folder containing the file you want to import.
3. Open the obstruction data file for any of the available skies (*Sky01ObstructionElevations*, *Sky02ObstructionElevations*, etc.).

   If the average or worst case obstruction data from multiple skylines will be used, then an extra step is required. In a spreadsheet program, open the *ObstructionElevation* file containing the average and maximum values as well as all skylines in the SunEye session. Make sure that the desired data (average or maximum) is in the third column, delete the other columns, and save the file as .csv with a name like *ObstructionElevationsAVG.csv*. Use this file as the obstruction data file in SAM.

   SAM displays the message "Azimuth-Altitude Table updated," populates the azimuth-altitude shading factor table, and enables the **Enable solar azimuth by altitude beam irradiance shading factor** option.
4. Be sure to enable and disable the other shading options as appropriate.

To import a SunEye hourly shading file:

1. In the Solmetric SunEye software (not the PV Designer software), on the **File** menu, click **Export Session Report and Data**.

   The SunEye software creates a set of files, and assigns a default name like *Sky01Shading.csv* to the hourly shading file. By default, the files are in a folder named *ExportedFiles* in the exported report folder.
2. In SAM, click **Edit shading** (on the PV Subarrays page or PVWatts Solar Array page) to open the

Edit Shading Data window, and click **Suneye hourly shading**, and navigate to the folder containing the shading file.

3. Open the shading file for any of the available skies (*Sky01Shading*, *Sky02Shading*, etc.). To use average shading for multiple skylines, open *AverageShading.csv*.

   SAM displays the message "Hourly Shading Factors for Beam Radiation updated," populates the hourly shading factor table, and enables the **Enable Hourly Beam Shading Factors** option.
4. To see the hourly data, click **Edit Data** under **Hourly Shading Factors for Beam Radiation**.
5. Be sure to enable and disable the other shading options as appropriate.
6. On the Location and Resource page, choose a weather file for the same location represented by the SunEye shading data.

Importing from SolarPathfinder Assistant

The SolarPathfinder Assistant software generates shading data in two formats: The obstruction table, which characterizes shading using an altitude-azimuth angle table to indicate solar positions that are blocked by nearby obstructions, and the hourly shading file, which lists hourly beam radiation shading factors. SAM can read data from both tables.

Use the obstruction table if you plan to model the system for different locations (assuming the same shading obstructions). Use the hourly shading factor table if you plan to model the system for a single location.

> **Note.** If you use the month-by-hour shading factor table, be sure that the weather data specified on the Location and Resource page is for the same location as the one where the Solar Pathfinder measurements were made.

To import a Solar Pathfinder obstruction table:

1. In SolarPathfinder Assistant, on the File menu, click **Export**, **Horizon Angles**.
2. In the Save window, specify the location and name of the data file.
3. In SAM, click **Edit shading** (on the PV Subarrays page or PVWatts Solar Array page) to open the Edit Shading Data window, and click **Solar Pathfinder obstructions**, and navigate to the folder containing the file you want to import.
4. Open the obstruction data file you saved in Step 2.

   SAM displays the message "Azimuth-Altitude Table updated," populates the azimuth-altitude shading factor table, and enables the Enable Azimuth-Altitude Shading Factors for Beam Radiation option.
5. Be sure to enable and disable the other shading options as appropriate.

To import a Solar Pathfinder Month by Hour shading file:

1. In SolarPathfinder Assistant, on the File menu, click **Export**, **Shading Data**.
2. In the Save window, specify the location and name of the data file.
3. In SAM, click **Edit shading** (on the PV Subarrays page or PVWatts Solar Array page) to open the Edit Shading Data window, and click **Solar Pathfinder month by hour shading**, and navigate to the folder containing the shading file.
4. Open the shading file you saved in Step 2.

   SAM displays the message "Hourly Shading Factors for Beam Radiation updated," populates the hourly shading factor table, and enables the Enable Hourly Beam Irradiance Shading Factors option.

5. To see the hourly data, click **Edit Data** under **Enable hourly beam irradiance shading factors**.
6. Be sure to enable and disable the other shading options as appropriate.
7. On the Location and Resource page, choose a weather file for the same location represented by the Solar Pathfinder shading data.

6.3 Microinverters

For an example of how to model a PV system with microinverters, see the sample file *PV Microinverters.zsam* (on the **File** menu, click **Open sample file**).

A microinverter is an inverter designed to be connected to a single module. A PV system with microinverters has a single inverter for each module, rather than the more traditional single inverter connected to the array or to individual strings of modules. Microinverters track each module's maximum power point independently, and minimize shading and module mismatch losses associated with string inverters.

Notes.

SAM assumes that all modules in the array operate at their maximum power point. The derate factor associated with module mismatch losses is an input on the Array page. When you model a system with microinverters, you should change the mismatch derate factor to 100% as described in the procedure below.

SAM's self shading model does not account for MPPT tracking of individual modules and is not suitable for use with microinverters.

To model a system with using microinverters in SAM:

1. On the Inverter page, choose the CEC Database inverter model.
2. Choose an Enphase inverter from the inverter list.
3. On the Module page, choose a module matched with the microinverter.

   For the Enphase microinverters, choose a module with rated maximum DC power ratings (Pmp) in the range of 200-240 Wdc, and a nominal maximum power DC voltage (Vmp) in the 30-60 Vdc range.

   Consult the Enphase datasheet for more specific details.
4. On the Array page, choose the **Specify number of modules and inverters** mode.
5. For **Modules per String**, enter 1.
6. To calculate the number of **Strings in Parallel**, divide the system's nameplate capacity by the module maximum power rating (Pmp) from the Module page:

   Strings in Parallel = System Nameplate Capacity (Wdc) / Module Maximum Power (Wdc)
7. For **Number of Inverters**, enter the value you calculated for the number of strings in parallel:

   Number of Inverters = Strings in Parallel
8. Under **System Derates**, for **Mismatch**, enter 100.

   Microinverters avoid system losses due to module-to-module mismatch.

9. On the PV System Costs, be sure that the inverter cost is appropriate for the microinverter.
10. On the Shading page, clear the **Enable Self-Shading Calculator** check box.

6.4 Flat Plate PV

The Flat Plate PV option represents the performance of a photovoltaic system using separate models to represent the performance of the module and inverter. You specify the module and inverter characteristics, array layout, derating factors, and optional shading, temperature correction, and backtracking parameters. The Flat Plate PV model calculates and reports detailed results, including the array's DC output, system's AC output, cell temperature, and the hourly efficiency of the array and inverters.

Use the Flat Plate PV option to model crystalline or thin-film modules, and for arrays with open rack, flush, gap, or building-integrated mounting.

The input pages for the Flat Plate PV model are:

- Location and Resource
- Module
- Inverter
- Array
- PV Subarrays

6.4.1 Sizing the Flat Plate PV System

For photovoltaic systems, SAM considers the system nameplate capacity to be the photovoltaic array's nameplate capacity in DC kilowatts:

- The system nameplate capacity is the module maximum power rating in DC kilowatts (at 1,000 W/m^2 and 25°C cell temperature) from the Module page multiplied by the number of modules in the array from the Array page:

  System Nameplate Capacity = Module Maximum Power (DC kW) × Number of Modules per String × Number of Strings in Parallel

- The DC-to-AC ratio is the system nameplate capacity in DC kilowatts divided by the product of the inverter maximum AC power rating in AC kilowatts from the Inverter page and the number of inverters from the Array page:

  DC-to-AC Ratio = System Nameplate Capacity (DC kW) ÷ (Inverter Maximum AC Power (AC kW) × Number of Inverters)

SAM uses the system nameplate capacity for capacity-related calculations such as costs that you specify in $/Wdc on the System Costs page, and the capacity factor and system performance factor that SAM reports in the Metrics table after running simulations.

SAM provides two options for specifying the numbers of modules and inverters in the PV system on the Array page:

- **Specify Desired Array Size** automatically sizes the system based on a desired array capacity in DC kilowatts and a DC-to-AC ratio..

- **Specify Numbers of Modules and Inverters** allows you to specify the number of modules per string, strings and inverters explicitly.

You might want to start your analysis using the Specify Desired Array Size mode for an initial array configuration, and then refine your design using the Specify Numbers of Modules and Inverters mode.

Use the Sizing Calculator: Specify Desired Array Size

This option is appropriate for very preliminary analyses to get a rough idea of a system's annual output, or as a first step in determining the number of modules per string, strings in parallel, and number of inverters for your system.

The array sizing calculator estimates the number of modules and inverters required for the array size and DC-to-AC ratio that you specify. It uses the manufacturer data sheet specifications of the modules and inverters from the Module and Inverter pages to calculate values for the numbers of modules per string, strings in parallel, and inverters. Because SAM makes the calculation before running simulations, it has no information about the expected output of the array for these calculations. However, SAM does display post-simulation messages based on the expected output of the photovoltaic array and inverter that you can use to refine the array size.

A better sizing approach is to optimize the inverter capacity to match the array's DC output rather than its nameplate capacity, because in an actual system the array rarely operates at its nameplate capacity. See the instructions for this approach under Size the System by Hand.

To size the photovoltaic array with the array sizing calculator:

1. Choose an inverter or specify its parameters on the Inverter page.
2. Choose a module or specify its parameters on the Module page.
3. On the Array page, choose **Specify desired array size**.
4. Type the array DC capacity value in kilowatts for **Desired Array Size**.
5. Type the ratio of DC array capacity to AC inverter capacity for **DC / AC Ratio**.

   SAM calculates values for **Modules per String**, **Strings in Parallel**, and **Number of Inverters**, and displays them in the **Actual Layout** column.
6. Verify that **Nameplate Capacity** under **Modules** is acceptably close to the desired capacity value you specified. If it is not, try choosing a slightly smaller or larger module or inverter to see if you can get closer to the desired capacity.
7. If the values for the inverter maximum DC voltage, or inverter minimum MPPT voltage and maximum MPPT voltage are zero, see the note below.
8. Also on the Array page, specify the AC derate factors, and if your analysis involves land costs, specify a land area packing factor.
9. On the PV Subarrays page, specify the tracking and orientation and system derate factors as appropriate.

Note for inverters in the CEC database with missing voltage limit data.

For some of the inverters in the CEC inverter database, the maximum DC voltage, minimum MPPT voltage, and maximum MPPT voltage are missing from the database, and SAM displays zeros for those variables on the Inverter and Array pages. For those inverters, there is insufficient information for SAM to determine whether the array rated voltages are within the acceptable ranges for the inverter. To properly size the array, you must refer to the inverter manufacturer specifications outside of SAM, and manually size the array by choosing the **Specify numbers of modules and inverters** mode.

PV Array Sizing Calculator Algorithm

The array sizing calculator uses the following algorithm to determine the number of modules and inverters in the array:

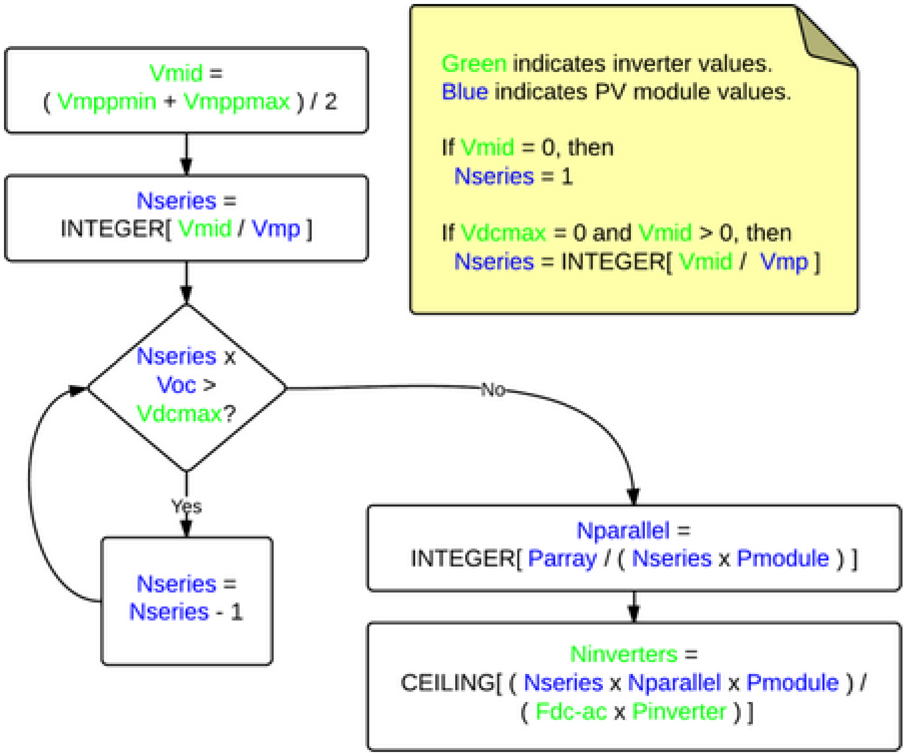
1. *Choose an initial number of modules per string that results in a string maximum power voltage close to the midpoint between the inverter minimum MPPT voltage and maximum MPPT voltage.*
2. *If the resulting string open circuit voltage exceeds the inverter maximum DC input voltage, reduce the number of modules per string by one until the string voltage is less than the inverter limit.*
3. *Calculate the number of strings in parallel required to meet the desired array capacity.*
4. *Calculate the number of inverters required to meet the DC-to-AC ratio you specify.*

The algorithm uses the following rules to size the array:

- The string open circuit voltage (Voc) is less than the inverter's maximum DC voltage.
- The ratio of the array's nameplate capacity in DC kW to the inverter total capacity in AC kW is close to the DC-to-AC ratio that you specify.

For the inverters in the CEC database with missing voltage limits:

- If the inverter minimum MPPT voltage and maximum MPPT voltage values are not available, then the number of modules per string is one.
- If the inverter maximum DC voltage is not available, but the minimum and maximum MPPT voltage values are, then the number of modules in series is determined from the MPPT voltage limits and the module maximum power voltage (see flowchart for details).



Flowchart of the PV Array Sizing Calculator Algorithm

Where:

Vdcmax	Inverter maximum DC voltage
Vmppmin	Inverter minimum MPPT voltage
Vmppmax	Inverter maximum MPPT voltage
Vmid	Midpoint between inverter minimum and maximum MPPT voltages
Pinverter	Inverter maximum AC power
Fdc-ac	DC-to-AC ratio
Voc	String open circuit voltage
Vmp	String maximum power voltage
Pmodule	Module maximum DC power
Nseries	Number of modules in series
Nparallel	Number of strings in parallel

Size the System by Hand: Specify Numbers of Modules and Inverters

This option is appropriate when you know the array layout, or to determine the optimal combination of modules, strings, and inverters. The following instructions explain one approach for choosing optimal values for the numbers of modules and inverters based on the array's expected DC output instead of its nameplate capacity.

To specify numbers of modules and inverters by hand:

1. Choose an inverter for the system or specify its parameters on the Inverter page.

   If you are using the Inverter CEC Database model, note that some inverters in the database do not have the values for the voltage limits that you will need to size the system. If you are using such an inverter, download the inverter's data sheet from the manufacturer's website and note the inverter maximum DC voltage, and minimum and maximum MPPT voltages.
2. Choose a module or specify its parameters on the Module page.
3. On the Array page, choose **Specify numbers of modules and inverters**.
4. For **Modules per String**, type a value that results in a string open circuit voltage less than but as close as possible to the inverter's maximum DC input voltage, and greater than the inverter's minimum MPPT voltage. For an initial estimate, you can try an integer value less than:

   Modules per String = [(Minimum MPPT Voltage + Maximum MPPT Voltage) ÷ 2] ÷ Module Maximum Power Voltage

   If the resulting string open circuit DC voltage on the Array page is greater than the inverter's maximum DC voltage, reduce the number of modules per string. You may also want to try a similar module or inverter with slightly lower or higher maximum power.
5. For **Strings in Parallel**, type a value that results in an array nameplate capacity that is close to your desired system DC capacity. You can choose an integer value close to the value:

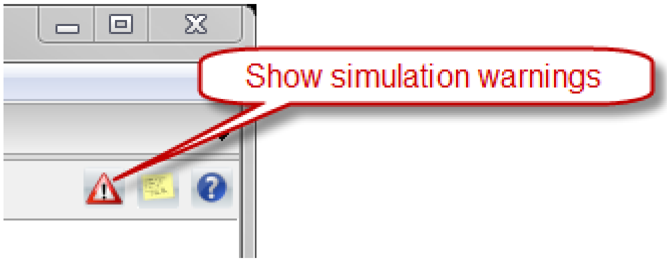
   Strings in Parallel = Array Nameplate Capacity (kWdc) × 1000 (W/kW) ÷ Module Maximum Power (Wdc) ÷ Modules Per String.
6. For **Number of Inverters**, type a value that results in a DC-to-AC ratio (shown in the message box) close to your desired value. To calculate the value, use the smallest integer greater than:

   Number of Inverters = (Modules per String × Strings in Parallel × Module Maximum Power (Wdc)) ÷ (DC-to-AC Ratio × Inverter Maximum AC Power (Wac))

   You may need to experiment with different sizes of modules and inverter within the same family to find a combination that works for your system.
7. On the Array page, specify the AC derate factors, and if your analysis involves land costs, specify a land area packing factor.
8. On the PV Subarrays page, specify the tracking and orientation and system derate factors as appropriate.
9. Run simulations.
10. On the Results page, check the capacity factor in the Metrics table to make sure it is a reasonable value. (For example, the capacity factor for the default system based on mono-crystalline modules in Phoenix, Arizona is about 17.5%.) If it seems too low, check that the total inverter capacity is not too low and limiting the system's AC output. If it is, you may want to try using a larger inverter, fewer modules, or a module from the same family with slightly lower capacity.
11. Also on the Results page, click Time Series, and display the Hourly Energy variable. This is the system's derated AC output in kWh/h. You can use this information to decide whether to reduce the inverter capacity. For example if you specified a 400 kW inverter capacity, but the time series data indicates the system rarely operates at that level, you could try reducing the number of inverters to model a system with 315 kW of inverter capacity to reduce the system's installation cost.
12. Be sure to check the post-simulation warning messages (see below) for information about the relative size of the inverter and array.
13. Adjust the numbers of inverters, modules per string, and strings in parallel, and run more simulations until you are satisfied with the cost and performance of the system.

Post-simulation Warning Messages

After completing simulations, SAM checks to see whether the inverter appears to be over- or under-sized based on the actual DC output of the array. If it finds any problems, SAM displays the Show Simulation Warnings button in the notification area at the top right corner of the main window. Click the button to display the warning message.



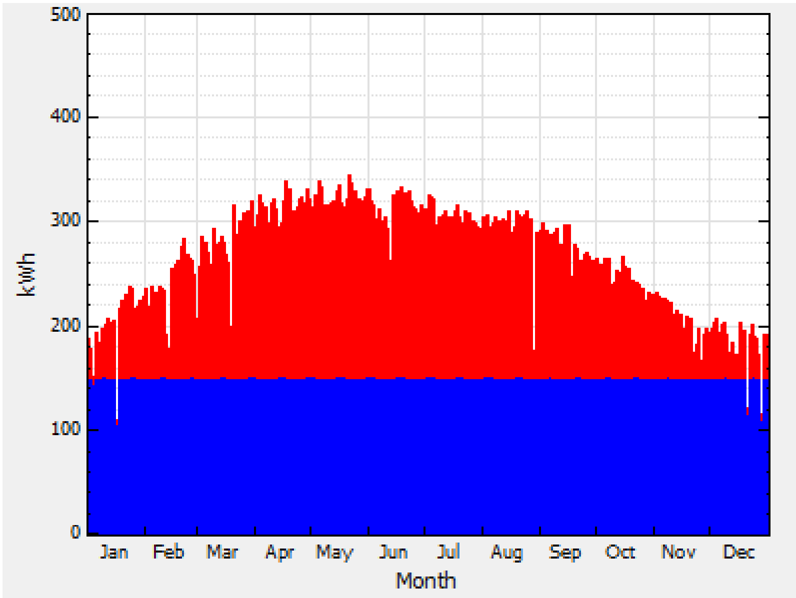
Post-simulation checks include:

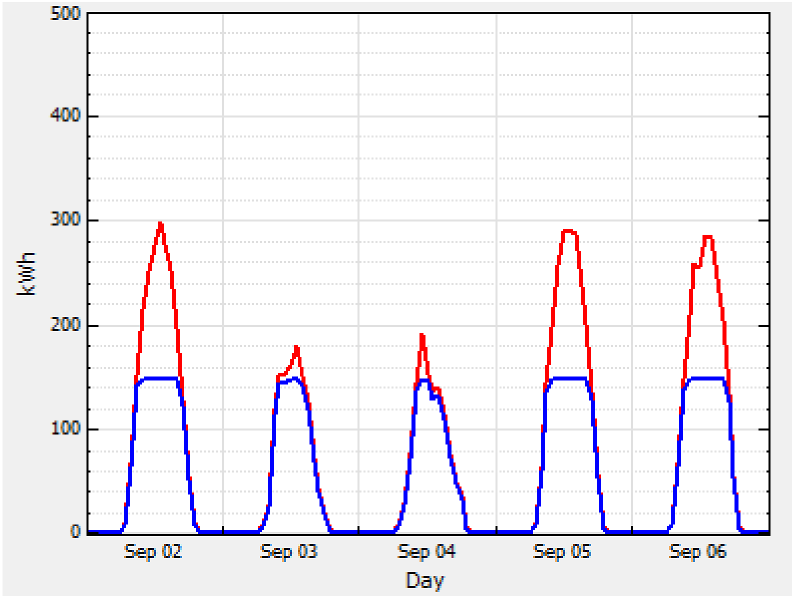
- *Inverter undersized:* The array output is greater than inverter rated capacity for one or more of the 8,760 hours in one year. SAM reports the number of hours that the array's simulated DC output is greater than the inverter's AC rated capacity.

  If the number of hours is small compared to the 8,760 hours in a year, you may choose to ignore the message. Otherwise, you may want to try increasing the inverter capacity.

  For example, for a system with 400 kWdc array capacity and 150 kWac total inverter capacity, SAM displays the following warning message: "pvsamv1: Inverter undersized: The array output exceeded the inverter rating 157.62 kWdc for 2128 hours."

  The following time series graphs show the array's DC output in red, and the system's AC output in blue, indicating that the inverter capacity is limiting the system's AC output:

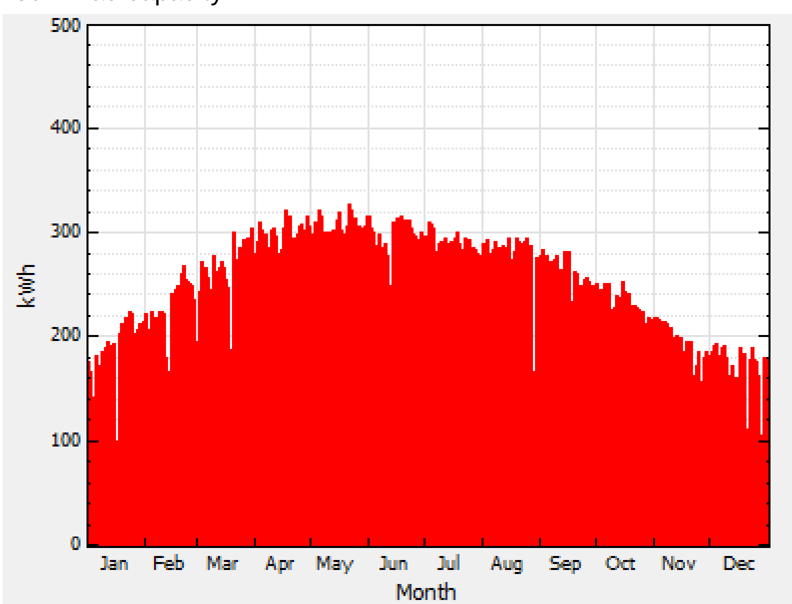




- *Inverter output less than 75 percent of inverter rated capacity*: SAM compares the inverter's maximum AC output to the total inverter AC capacity and displays a simulation warning if the inverter's maximum AC output is less than 75% of the total inverter rated AC capacity.

  For example, for a system with 400 kWdc array capacity and 750 kWac inverter capacity, SAM displays the following warning message: "pvsamv1: Inverter oversized: The maximum inverter output was 43.13% of the rated value 750 kWac."

  In this case, the time series graph of gross AC output shows that the inverter output never reaches the 750 kWac capacity.

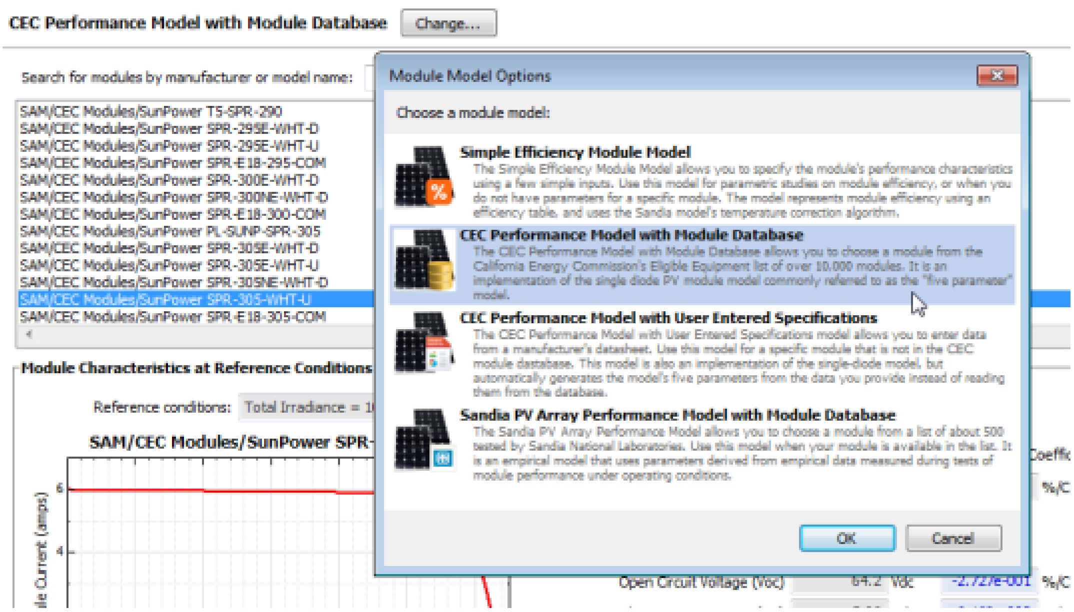


6.4.2 Module

The Module page allows you to choose a photovoltaic module performance model and either choose a module from a list, specify module parameters from a module manufacturer's data sheet, or specify basic module efficiency parameters. SAM can only model a photovoltaic system with a single type of module.

Specify the number of modules in the system on the Array page, and orientation, tracking, shading, and other parameters on the PV Subarrays page.

SAM displays the name of the active module model at the top of the Module page. Click **Change** to choose a different model.



You can choose from four different module performance models:

- Sandia PV Array Performance Model with Module Database calculates hourly efficiency values based on data measured from modules and arrays in realistic outdoor operating conditions. The database includes modules with different cell types, including crystalline silicon, and various thin film technologies.
- California Energy Commission (CEC) Performance Model with Module Database predicts module performance based on a database of module characteristics determined from module ratings. Like the Sandia model, the CEC model calculates hourly efficiency values, and allows you to choose from a list of a commercially-available modules. The CEC module database tends to be more up-to-date than the Sandia database.
- CEC Performance Model with User Entered Specifications uses the same algorithms as the CEC model with Module Database, but allows you to enter your own module specifications from a manufacturer's data sheet instead of relying on parameters provided by the California Energy Commission.
- Simple Efficiency Module Model is a simple representation of module performance that requires you to provide the module area, a set of conversion efficiency values, and temperature correction parameters. The simple efficiency model is the least accurate of the three models for predicting the performance of specific modules. It is useful for preliminary performance predictions before you have selected a specific module, and allows you to specify a module efficiency and temperature performance parameters, which is useful for analyses involving sensitivity or parametric analysis.

Note. You can also model a photovoltaic system using the simpler PVWatts model, or concentrating photovoltaic system using the High-X Concentrating PV (HCPV) model. To use these options you must choose the appropriate option in the Technology and Market window when you create a new file or case.

Contents

Guidelines for Choosing a Module Performance Model

The module performance model calculates the hourly DC electrical output of a single module based on the module's specifications on the Module page, and the hourly incident solar radiation (plane-of-array irradiance) calculated from data in the weather file specified on the Location and Resource page. SAM assumes that the system consists of an array of identical modules, and uses the array orientation and tracking information from the Array page to determine the module's orientation with respect to the sun.

The photovoltaic array's electric output depends on the number and configuration of modules in the array, and the soiling and pre-inverter derate factors that you specify on the Array page. The array's electrical output is fed to one or more inverters, whose characteristics appear on the Inverter page.

Note. SAM assumes that the array operates at its maximum power point. During simulations, SAM does not track changes in voltage and current levels in the system.

Each of the module performance models uses a different algorithm to predict module performance. In general, if you are modeling a system that uses a particular brand and type of flat-plate PV module, you should first look for the module in the Sandia database, and then in the CEC database. If you do not find the module in either database, you can either choose a similar module from one of the databases, or use the CEC Performance Model with User Entered Specifications.

The Flat Plate Simple Efficiency Model is ideal for analyses involving explorations of the relationship between module efficiency and the system's performance and cost of energy because it allows you to specify the module efficiency as an input. The Sandia and CEC models with module databases do not allow you to modify module parameters such as efficiency.

- The Sandia PV Array Performance Model with Module Database calculates hourly efficiency values based on data measured from modules and arrays in realistic outdoor operating conditions. The database includes modules with different cell types, including crystalline silicon, and various thin film technologies.

- The California Energy Commission (CEC) Performance Model with Module Database predicts module performance based on a database of module characteristics determined from module ratings. Like the Sandia model, the CEC model calculates hourly efficiency values, and allows you to choose from a list of a commercially-available modules. The CEC module database tends to be more up-to-date than the Sandia database.
- The CEC Performance Model with User Entered Specifications uses the same algorithms as the CEC model with Module Database, but allows you to enter your own module specifications from a manufacturer's data sheet instead of relying on parameters provided by the California Energy Commission.
- The Simple Efficiency Module Model is a simple representation of module performance that requires you to provide the module area, a set of conversion efficiency values, and temperature correction parameters. The simple efficiency model is the least accurate of the three models for predicting the performance of specific modules. It is useful for preliminary performance predictions before you have selected a specific module, and allows you to specify a module efficiency and temperature performance parameters, which is useful for analyses involving sensitivity or parametric analysis.

Table 3. Guidelines for choosing a photovoltaic module performance model.

Use this model...	...if your analysis involves...	Comments
Sandia with Module Database *Model based on field test data.*	estimates of module performance for crystalline or thin-film modules.	If your module is in both the Sandia and CEC lists, use the Sandia model.
CEC with Module Database *Model based on module ratings.*	estimates of module performance for crystalline-silicon modules or for new modules recently available on the market.	The CEC model may not accurately model thin film modules.
CEC with User Entered Specifications *Model based on module ratings.*	estimates of module performance for crystalline-silicon modules not available in the Sandia or CEC database.	You can find module parameters on the module manufacturer's data sheet.
Simple Efficiency Module Model *Simple efficiency curve with temperature correction.*	sensitivity or parametric studies on module efficiency or temperature coefficients, or for preliminary analyses before you have chosen a specific module.	

Modeling Thin-film Modules

For modules based on thin-film cell technology, including amorphous silicon, copper indium diselenide (CIS), cadmium telluride (CdTe), and heterojunction with intrinsic thin layer (HIT), the Sandia model may provide more accurate results than the CEC and simple efficiency models, which do not adequately represent module performance at low-light levels. For best results, if you are modeling a thin-film module, look for the module in the Sandia database. If the module is not available in the Sandia database, you may want to use a module from the database with similar characteristics to the one you are modeling. Use the table below to help identify the thin-film modules in the Sandia database.

Table 4. Thin-film module manufacturers and model numbers available in the Sandia module database.

Cell Type	Manufacturer	Model Series or Number
amorphous tandem junction (2-a-Si)	Solarex	MST
	EPV Solar	EPV-40
amorphous silicon triple junction (3-a-Si)	Uni-Solar	PVL, SHR, US, USF
cadmium telluride (CdTe)	BP Solar	BP980, BP990
	First Solar	FS
copper indium diselenide (CIS)	Shell Solar	ST
	Siemens Solar	ST
amorphous silicon heterojunction (HIT-Si)	Sanyo	HIP

Sandia PV Array Performance Model with Module Database

The Sandia PV Array Performance model consists of a set of equations that provide values for five points on a module's I-V curve and a database of coefficients for the equations whose values are stored in the Sandia Modules library. The coefficients have been empirically determined based on a set of manufacturer specifications and measurements taken from modules installed outdoors in real, operating photovoltaic systems.

> **Note.** SAM's Sandia module library contains parameters for modules involved in Sandia's Test and Evaluation program, http://energy.sandia.gov/?page_id=279.
>
> If you are a module manufacturer and would like to add your module to the Sandia database, you should contact Sandia National Laboratories directly. See http://energy.sandia.gov/?page_id=2772 for the PV Testing and Evaluation contact.

The Sandia model is described in King et al, 2004. Photovoltaic Array Performance Model. Sandia National Laboratories. SAND2004-3535. http://prod.sandia.gov/techlib/access-control.cgi/2004/043535.pdf. Also see the Sandia PV Modeling and Analysis website at http://energy.sandia.gov/?page_id=2493 for more on PV system performance modeling.

To use the Sandia photovoltaic model:

1. On the Module page, choose **Sandia PV Array Performance Model**.
2. Choose a module from the list of available modules. SAM displays the module's characteristics and model coefficients.

   When you choose a module from the list, SAM displays the module characteristics at reference conditions on the Module page. Internally, the model applies a set of coefficients from the Sandia Modules library to the simulation equations.

3. Choose a module structure from the three available options (displayed as front material / cell / back material). See Temperature Correction for details. Module manufacturers typically include a description of the front material, and frame or back material in a mechanical characteristics section of module specification sheets.

> **Notes.**
>
> The current version of the Sandia database contains a single concentrating PV module, listed as Entech 22X Concentrator [1994].
>
> The first several items in the module list are arrays instead of single modules. The arrays are indicated by the word "Array" in the name. The array coefficients account for some losses not accounted for in the single module parameters, including module mismatch, diodes and connections, and DC wiring losses. When you use an array from the database, you should be sure that the Pre-Inverter derate factor on the Array page does not include these losses.

Module Characteristics at Reference Conditions

SAM displays the module characteristics so that you can compare modules in the database to manufacturer specifications or to different modules in the database.

Reference Conditions

The reference conditions describe the incident solar radiation, air mass, ambient temperature, and wind speed that apply to the module characteristics. The module efficiency, power, current, voltage, and temperature coefficients values are those for the module operating at the reference conditions.

Efficiency (%)

The module's rated efficiency at reference conditions. SAM displays this value for reference only. During simulations, the model calculates an efficiency value for each hour, which you can see in the time series output data in the Tables on the Results page.

Maximum Power (Pmp), Wdc

The module rated power in DC Watts. Equal to the product of the maximum power voltage and maximum power current.

Maximum Power Voltage (Vmp), Vdc

Maximum power voltage in DC Volts under reference conditions.

Maximum Power Current (Imp), Adc

Maximum power current in DC Amps under reference conditions. Defines the maximum power point on the module's I-V curve.

Open Circuit Voltage (Voc), Vdc

Open circuit voltage under reference conditions. Defines the open circuit point on the module's I-V curve.

Short Circuit Current (Isc), Adc

Short circuit current under reference conditions. Defines the short circuit point on the module's I-V curve.

Temperature Coefficients

SAM displays the temperature coefficients in %/°C and W/°C at the different points on the power curve.

Module Structure and Mounting

This option determines the coefficients that SAM uses to calculate the cell temperature in each hour of the simulation. The default option is **User Database Values**, which displays the coefficients from the measured data at reference conditions. See Temperature Correction for details.

Physical Characteristics

Material

A description of the semiconductor technology used in the photovoltaic cells.

2-a-Si: dual-junction amorphous silicon

3-a-Si: triple-junction amorphous silicon

CdTe: cadmium telluride

CIS: copper indium diselenide

HIT-Si: amorphous silicon heterojunction

c-Si: single-crystal silicon

mc-Si: multi-crystalline silicon

Vintage

The year that module coefficients were added to the database.

The letter "E" indicates that the coefficients were estimated from a combination of published manufacturer specifications and data from the outdoor testing of a similar module. Entries without an "E" are for modules whose coefficients were derived entirely from outdoor tests involving one more or more modules of that type.

Because the tested modules (listed without an "E") may have had different average power ratings than production versions of the same module, the database typically also includes an "E" entry for each of the tested modules that represents the average power rating specified by the manufacturer.

Module Area, m2

The total area of the module, including spaces between cells and the frame.

Number of Cells

Total number of cells in the module, equal to the product of the number of cells in series and number of cell strings in parallel.

Number of Cells in Series

Number of cells connected in series per cell string.

Number of Cell Strings in Parallel

Number of cell strings connected in parallel per module.

Sandia Temperature Correction

The Sandia temperature correction algorithm calculates a temperature correction factor that accounts for efficiency losses due to heating of the module during the day when the sun is shining. The algorithm calculates an hourly module temperature as a function of the solar radiation, ambient temperature, and wind speed in a given hour, and a set of properties describing the thermal characteristics of the cell and module.

For more details about the algorithm, see King et al, 2004. *Photovoltaic Array Performance Model*. Sandia National Laboratories. SAND2004-3535. http://prod.sandia.gov/techlib/access-control.cgi/2004/043535.pdf

> **Note**. The SAM temperature correction algorithms do not account for cooling strategies used in some innovative photovoltaic systems.

Guidelines for choosing the Module Structure - Mounting (a, b, dT) parameters

The *a*, *b*, and *dT* parameters determine the relationship between ambient temperature and module temperature. See the equations below for details.

SAM allows you to choose from a set of pre-determined values of the parameters for different module mounting options, or specify your own values for the parameters. For the Concentrating PV model, you can assign a set values to the parameters, or specify your own.

- For most analyses involving flat-plate modules mounted on open racks, choose **Use Database Values**. These are the values determined empirically during testing of the module. Most of the modules in the database were tested on open racks.
- To see how a flat-plate module might perform under different mounting conditions, choose an appropriate option from the list. Be sure to choose an option that is consistent with the module you are modeling. You may need to refer to the module's specification sheet for information about its structure.
- For the Concentrating PV model, use the default values (click **Default Temperature Inputs**) unless you have a set of *a*, *b*, and *dT* values for your module. See the equations below for details.
- If you understand the Sandia model well enough to generate your own temperature correction coefficients, choose **User Defined**, and type your own values for *a*, *b*, and *dT*. See the equations below for details.

Table 5. Description of the module structure and mounting options.

Module Structure and Mounting	Description
Glass/Cell/Polymer Sheet Open Rack	Solar cells are between a glass front and polymer back, and the module is mounted on an open rack allowing air to circulate freely around the module.
Glass/Cell/Glass Open Rack	Solar cells are between a glass front and glass back, and the module is mounted on an open rack allowing air to circulate freely around the module.
Polymer/Thin Film/Steel Open Rack	Solar cells are between a transparent polymer front and steel back, and the module is mounted on an open rack allowing air to circulate freely around the module.
Glass/Cell/Polymer Sheet Insulated Back	Solar cells are between a glass front and polymer back, and the module is mounted directly to a building surface in a building-integrated PV (BIPV) application preventing air from flowing over the module back.
Glass/Cell/Glass Close Roof Mount	Solar cells are between a glass front and glass back, and the module is mounted on a rack with little clearance between the building surface and module back allowing little air to flow over the module back.

Sandia Temperature Correction Method

SAM uses the Sandia temperature correction method to calculate a module and cell temperature and temperature correction factor for the Sandia, Simple Efficiency and High-X Concentrating PV (HCPV) models. The model uses the temperature correction factor to adjust each hour's module efficiency value: The higher the module's temperature in a given hour, the lower the module's efficiency in that hour.

You can explore temperature effects on the array's performance in the time series output data. The data shows the hourly cell temperature, along with the solar radiation, wind speed, and ambient temperature.

The temperature correction equations use the following input values from the Module page:

- Temperature coefficients. The Sandia model uses the four values listed in the Temperature Coefficients column. The Simple Efficiency and Concentrating PV models use the single temperature coefficient of power value.
- Temperature correction coefficients: a, b, and dT. For the Sandia and Simple Efficiency models, the three values appear under the Module Structure - Mounting option. For the Concentrating PV model, the values appear below the temperature coefficient variable.

The equations use four hourly data sets from the weather file. You can see the hourly data by either viewing the weather data from the Location and Resource page, or viewing the time series results data after running simulations:

- Incident direct normal radiation
- Incident diffuse radiation
- Ambient temperature
- Wind speed

Table 6. Empirically-determined coefficients from the Sandia database for each of the module structure and mounting options available on the Module page.

Module Structure and Mounting	a	b	dT °C
Glass/Cell/Polymer Sheet Open Rack	-3.56	-0.0750	3
Glass/Cell/Glass Open Rack	-3.47	-0.0594	3
Polymer/Thin Film/Steel Open Rack	-3.58	-0.113	3
Glass/Cell/Polymer Sheet Insulated Back	-2.81	-0.0455	0
Glass/Cell/Glass Close Roof Mount	-2.98	-0.0471	1
Concentrating PV Module	-3.2	-0.09	17
User Defined	-99	0	0

Note. The default values for the User Defined option effectively remove temperature correction from the model so that the cell temperature is equal to the ambient temperature.

Table 7. Sample temperature coefficient values for different cell types based on an informal survey of manufacturer module specifications.

Cell Type	Maximum Power Temperature Coefficient (%/°C)

Monocrystalline Silicon	-0.49
Polycrystalline Silicon	-0.49
Amorphous Silicon	-0.24
Amorphous Silicon Triple Junction	-0.21
Copper Indium Gallium DiSelenide (CIGS)	-0.45
Cadmium Telluride (CdTe)	-0.25

Sandia Temperature Correction Equations

The temperature correction algorithm first calculates the module back temperature based on the incident solar radiation, *a* and *b* coefficients, and the ambient temperature and wind speed:

$$T_{\text{Back}} = E_{\text{Incident}} \cdot e^{a + b \cdot v_{\text{Wind}}} + T_{\text{Ambient}}$$

> **Note.** SAM assumes that the ambient temperature and wind speed data in the weather file are mid-hour values and that the radiation values are end-of-hour values. SAM interpolates temperature and wind speed values by averaging the current hour value with the previous hour value.

Next, the cell temperature is calculated based on the module back temperature, incident radiation, and dT:

$$T_{\text{Cell}} = T_{\text{Back}} + \frac{E_{\text{Incident}}}{E_0} \cdot dT$$

The temperature correction factor $F_{TempCorr}$ is:

$$F_{\text{TempCorr}} = 1 + \gamma \cdot (T_{\text{Cell}} - T_{\text{Ref}})$$

In general, the temperature corrected module power is the product of the power calculated by the module model and the temperature correction factor. Each module model (Sandia, Simple Efficiency, Concentrating PV) uses a different algorithm to calculate the module power before temperature correction:

$$P_{\text{TempCorr}} = P_{\text{BeforeTempCorr}} \cdot F_{\text{TempCorr}}$$

Where,

$E_{Incident}$ (W/m^2)	The sum of the direct normal and diffuse radiation for the current hour in the weather data. SAM determines this value based on the data in the weather file.
E_0 (W/m^2)	The reference total incident radiation, equal to 1000 W/m^2.
T_{ref} (°C)	The reference temperature in degrees Celsius, equal to 25°C.
gamma (%/°C)	The maximum power temperature coefficient from Module page.
a, b	Values from the Module page. They are empirically-determined coefficients accounting for the effect of wind on the module temperature: a defines the module temperature upper limit (at low wind speed and high solar radiation levels), and b defines the rate at which module temperature decreases as wind speed increases. The values depend on the module's construction, which determines its ability to absorb and shed heat. See the table above for typical values.

dT	Value from the Module page. The temperature difference between the cell and module back surface at the reference incident radiation of 1000 W/m^2. The value depends on how the module is mounted in the system, which determines how much air comes into contact with the module back surface. See the table above for typical values.
v_{Wind} (m/s)	Wind speed from the weather file in meters per second.
$T_{Ambient}$ (°C)	Ambient temperature from weather file.
$F_{TempCorr}$	Temperature correction factor
$P_{BeforeTempCorr}$	Module power before temperature correction
$P_{TempCorr}$	Temperature-corrected module power

CEC Performance Model with Module Database

The California Energy Commission (CEC) Performance Model uses the University of Wisconsin-Madison Solar Energy Laboratory's five-parameter model with a database of module parameters for modules from the database of eligible photovoltaic modules maintained by the California Energy Commission (CEC) for the California Solar Initiative.

The five-parameter model calculates a module's current and voltage under a range of solar resource conditions (represented by an I-V curve) using an equivalent electrical circuit whose electrical properties can be determined from a set of five reference parameters. These five parameters, in turn, are determined from standard reference condition data provided by either the module manufacturer or an independent testing laboratory, such as the Arizona State University Photovoltaic Testing Laboratory.

Note. SAM's CEC module library contains parameters for the modules in the List of Eligible SB1 Guidelines Compliant Photovoltaic Modules at http://www.gosolarcalifornia.org/equipment/pv_modules.php. We try to keep the library as current as possible, but there may be periods when SAM's library is out of date. If the library appears to be out of date, you can check for updates by clicking the link on the Help menu to see if we have prepared a new module library.

If you are a module manufacturer and would like to add your module to the CEC database, you should contact the CEC directly. See http://www.gosolarcalifornia.ca.gov/equipment/add.php.

The five-parameter model is described in De Soto 2004, Improvement and Validation of a Model for Photovoltaic Array Performance, Master of Science Thesis, University of Wisconsin-Madison. http://minds.wisconsin.edu/handle/1793/7602.

To use the CEC photovoltaic model:

1. On the Module page, choose **CEC Performance Model**.
2. Choose a module from the list of available modules. SAM displays the model's characteristics and model coefficients.

   When you select a module from the CEC database on the Module page, SAM displays module's parameters. You can see the complete set of parameters in the Module library by using SAM's library editor.

Module Characteristics at Reference Conditions

Efficiency, %

The module's rated efficiency at reference conditions. SAM displays this value for reference only. During simulations, the model calculates an efficiency value for each hour, which you can see in the time series output data.

Maximum Power (Pmp), Wdc

The module rated power. Equal to the product of the maximum power voltage and maximum power current.

Maximum Power Voltage (Vmp), Vdc

Reference maximum power voltage at the reference conditions.

Maximum Power Current (Imp), Adc

Reference maximum power current at the reference conditions.

Open Circuit Voltage (Voc), Vdc

Reference open circuit voltage at the reference conditions.

Short Circuit Current (Isc), Adc

Reference short circuit current at the reference conditions.

Temperature Coefficients

SAM displays the temperature coefficients in %/°C and W/°C at maximum power, open circuit, and short circuit.

The temperature coefficients are based on data collected from laboratory test results and may not match coefficients provided by the manufacturer on the module's data sheet.

CEC Temperature Correction

The CEC model provides two modes for modeling the effect of cell temperature on module performance:

- The NOCT method determines the cell temperature based on the nominal operating cell temperature (NOCT) specified in the module parameters. In SAM 2010.11.9 and earlier versions, this was the only available temperature correction option for the CEC mode. For a description, see De Soto 2004, Improvement and Validation of a Model for Photovoltaic Array Performance, Master of Science Thesis, University of Wisconsin-Madison. http://minds.wisconsin.edu/handle/1793/7602.
- The mounting-specific method uses a steady state heat transfer model to calculate cell temperatures, and is described in Neises T, 2011. Development and Validation of a Model to Predict the Temperature of a Photovoltaic Cell. Master of Science Thesis. University of Wisconsin-Madison. http://sel.me.wisc.edu/publications/theses/neises11.zip.

Notes.

The temperature correction algorithms use wind speed and ambient temperature data from the weather file. SAM assumes that the ambient temperature and wind speed data in the weather file are mid-hour values and that the radiation values are end-of-hour values. SAM interpolates temperature and wind speed values by averaging the current hour value with the previous hour value.

When you specify a vertical or horizontal mounting structure option, SAM also uses wind direction data in the cell temperature calculation. Note that for the NREL TMY weather data files, the degree of uncertainty in the wind direction data is high.

Temperature Correction Mode

- **NOCT cell temp model.** Choose this option to use the nominal operating cell temperature (NOCT) method from the original five-parameter model.
- **Mounting specific cell temp model.** Choose this option to use the steady state heat transfer model for calculating the cell temperature, and when you want to model different module mounting options.

Nominal operating cell temperature (NOCT) parameters

The NOCT parameters are active in NOCT Cell Temp Model mode.

- **Mounting standoff** Choose the option that best describes how the module is mounted: Ground or rack mounted when there is a when there is a lot of space between the module back and the ground or roof surface; For roof-mounted modules, choose a distance between the module back and roof in inches; or choose building-integrated for a module that is part of the building structure.

  For standoff heights less than 0.5 inches, and between 0.5 inches and 3.5 inches, SAM increases the NOCT value by several degrees as the standoff height decreases to account for reduced airflow between the module and roof surface. This is the same approach as is used in the CECPV Calculator Spreadsheet, available at http://gosolarcalifornia.ca.gov/tools/nshpcalculator/index.php.
- **Array height** Choose the option that best describes the height of the array from the ground.

Mounting configuration heat transfer cell temperature model

These parameters are active in Mounting Specific Cell Temp Model mode.

The mounting configuration affects the movement of air around the module and the transfer of heat between the module and the building surface or ground. SAM assumes that all modules in the array use the same mounting configuration.

- **Mounting Configuration** Choose the option that best describes how the modules are mounted: Rack when modules are mounted on open racks that allow ambient air to flow freely over the front and back of the modules; Flush when modules are in direct contact with a roof or wall, preventing air from flowing over the back of the module; Integrated when modules form part of the roof or wall so that the back of the module is in contact with the indoor air (when you specify integrated mounting, you must also specify the temperature behind the module); Gap for modules that are mounted with a space between the module and building surface that allows limited air flow over the back of each module (when you specify gap mounting, you must also specify the mounting structure orientation and gap spacing).
- **Heat Transfer Dimensions** Choose whether you want SAM to calculate the cell temperature based on the module or array dimensions. The Array Dimensions option assumes that modules in the array are in direct contact with each other and results in a higher calculated cell temperatures than the

Module Dimensions option. Use the Array Dimensions option for more conservative array output estimates.

- **Mounting Structure Orientation** (gap mounting configuration only) Choose how the mounting structure interferes with airflow under the modules for the gap mounting configuration: None if the mounting structure does not impede air flow over the back of the modules; vertical supporting structures if the mounting structures on module back are perpendicular to the roof ridge and impede air flow parallel to the ridge; or horizontal supporting structures if the mounting structures are parallel to the roof ridge and impede air flow perpendicular to the ridge.

Module Width

Length of side of module parallel to the ground.

Module Height

SAM calculates this value by dividing the module area from the parameter library by the module width that you specify.

Module Height (m) = Module Area (m²) ÷ Module Width

When you choose array dimensions for the heat transfer dimensions, you must also specify how modules are physically configured in the array.

Rows of modules in array (array heat transfer dimensions only)

Assuming a rectangular array, the number of rows of modules, where a row is parallel to the line defined by the Module Width variable.

Columns of modules in array (array heat transfer dimensions only)

Assuming a rectangular array, the number of modules along the side perpendicular to the line defined by the module width variable.

Note. The rows and columns of modules variables are independent of the similar variables on the Array page and Shading page. Before running simulations, verify that the values on the different pages are consistent.

Temperature behind the module (integrated mounting configuration only)

The indoor air temperature for the integrated mounting configuration option. SAM assumes a constant indoor air temperature.

Gap spacing (gap mounting configuration only)

The distance between the back of the modules and the roof or wall surface for the gap mounting configuration option.

Physical Characteristics

Material

A description of the semiconductor technology used in the photovoltaic cells.

1-a-Si: single-junction amorphous silicon

2-a-Si: dual-junction amorphous silicon

3-a-Si: triple-junction amorphous silicon

a-Si/nc: amorphous silicon - microcrystalline silicon tandem module

CdTe: cadmium telluride

CIGS: copper indium gallium sulfide

CIS: copper indium diselenide

HIT-Si: amorphous silicon heterojunction

Mono-c-Si: single-crystal silicon

Multi-c-Si: multi-crystalline silicon

Module Area

The total area of the module, including spaces between cells and the frame.

Number of Cells

Number of cells per module.

Additional Parameters

T_noct

Nominal operating cell temperature

A_ref

Modified ideality factor at reference conditions

I_L_ref

Photocurrent at reference conditions

I_o_ref

Reverse saturation current at reference conditions

R_s

Series resistance (constant)

R_sh_ref

Shunt resistance at reference conditions

Simple Efficiency Module Model

The flat-plate photovoltaic simple efficiency module model calculates the module's hourly DC output assuming that the module efficiency varies with radiation incident on the module as defined by the radiation level and efficiency table. The model makes an adjustment for cell temperature using the Sandia temperature correction algorithm.

To use the simple efficiency module model:

1. On the Module page, choose **Simple Efficiency Module Model**.
2. Enter a temperature coefficient. This is the number typically reported on manufacturer specification sheets as the maximum power coefficient. See Sandia Temperature Correction for suggested values.
3. Enter the module's total cell area in square meters, equivalent to the product of the cell area and number of cells.
4. Type values for the module's maximum power and open circuit voltages. SAM uses these values for

array sizing on the Array page.

5. Choose a module structure from the three available options (displayed as front material / cell / back material). See Sandia Temperature Correction for details.

   Module manufacturers typically include a description of the front material, and frame or back material in a mechanical characteristics section of module specification sheets.

6. In the Radiation Level and Efficiency Table, enter an efficiency value for each of the five incident global radiation reference values in increasing order. If you are defining the efficiency curve with fewer than five efficiency values, *you must include five radiation values*, but you can assign the same efficiency value to more than one radiation value. For example, to represent a module with 13.5% constant efficiency, you would assign the value 13.5 to each of the five radiation values 200, 400, 600, 850, 1000.

7. Choose the radiation level that represents the reference value, often 1000 W/m^2 for flat-plate modules.

   SAM uses the reference value to calculate the module's rated power, displayed as the Power variable on the Module page.

Characteristics

The module characteristics define the module's capacity, efficiency, and thermal characteristics.

Maximum Power (Pmp), Wdc

The module's rated maximum DC power at the reference radiation indicated in the radiation level and efficiency table. SAM uses this value to calculate the array cost on the PV System Costs page, but not in simulation calculations. The module power is the product of the reference radiation, reference efficiency, and area.

Temperature Coefficient (Pmp), %/C

The rated maximum-power temperature coefficient as specified in the module's technical specifications. See Sandia Temperature Correction for details.

Area, m2

The module collector area in square meters. To calculate the area for a given module power rating at a given reference radiation level, divide the power rating by the module efficiency and radiation level. For example, a module with a 100 W rating and 13.5% efficiency at 1000 W/m^2 would requires an area of 100 W / (0.135 × 1000 W/m^2) = 0.74074 m^2.

Maximum Power Voltage (Vmp)

The voltage at the module's maximum power point. SAM uses this value for Array sizing.

Open Circuit Voltage (Voc)

The module's open circuit voltage. SAM uses this value for Array sizing.

Module Structure and Mounting

The module's front and back materials (front material/cell/back material) used in the Sandia temperature correction algorithm.

Radiation Level and Efficiency Table

Radiation (W/m2)

The incident global (beam and diffuse) radiation level at which the given efficiency value applies.

Efficiency (%)

The module conversion efficiency at a given incident global radiation level. SAM calculates an efficiency value for each hour in the simulation using linear extrapolation to determine the value based on radiation data from the weather file. The efficiency values represent the efficiency of conversion from incident global radiation to DC electrical output.

Reference

Indicates the value to use for the reference calculations. SAM uses the reference values to calculate the module's rated power on which module costs are based.

Diffuse utilization factor

This advanced input allows you to adjust the diffuse component of the radiation incident on the module. For most applications, you should use the default value of 1. For modules that do not use all of the diffuse radiation, such as low-x concentrator, you can use a value less than one.

For each hour of the year, the flat-plate single-point efficiency model calculates the module DC output as the product of the total incident global radiation, module area, and temperature correction factor:

$$P_{\mathrm{mp\_Module}} = E_{\mathrm{TotalIncident}} \cdot A_{\mathrm{Module}} \cdot \eta_{\mathrm{Module}} \cdot F_{\mathrm{TempCorr}}$$

Where,

$E_{TotalIncident}$ (W/m^2)	Total incident radiation from the weather data processor.
A_{Module} (m^2)	The module area in square meters.
n_{Module}	Module efficiency at a given incident global radiation level, calculated by extrapolating values from the Radiation Level and Efficiency Table.
$F_{TempCorr}$	Temperature correction factor. See Sandia Temperature Correction for details.

CEC Performance Model with User Entered Specifications

The CEC Performance Model with User Entered Specifications allows you to run the CEC module model with module specifications from test data supplied by the module manufacturer or an independent testing laboratory, or data from a manufacturer's module data sheet.

When you use the model, you first enter a set of specifications to generate a set of coefficients for the module on the Module page, and then run simulations of the PV system after specifying the rest of the system on the Array, Inverter, and other input pages.

SAM uses the module specifications you provide to calculate a set of parameters at reference conditions for the equivalent electrical circuit in the CEC module model. During simulations, the model adjusts temperature and incident irradiance coefficients to calculate the module efficiency at operating conditions other than STC. Note that the model does not account for all non-linear effects in the relationship of module power and irradiance.

The calculations involve a combination of empirical regressions and heuristic methods to automatically solve a multidimensional set of non-linear equations. An error checking algorithm ensures that the model can find solutions for most modules.

Note. SAM stores the calculated parameters with the case in your zsam file. It does not store them in a library that you can use in other files or cases. To use a module in a different file or case, either save a copy of the file, or duplicate the case. If you plan to enter parameters for many modules for use with different SAM files, you can create your own library of modules, see Libraries for details.

If you use specifications from a manufacturer's data sheet for a module that exists in the CEC Performance Model with Module Database, SAM may calculate a different set of parameters than those in the CEC library. That is because the specifications used to generate parameters in the CEC library are based on specifications provided by third party testing facilities, which may differ from data on the manufacturer data sheet.

To use the CEC Performance Model with User Entered Specifications:

1. On the Module page, choose **CEC Performance Model with User Entered Specifications**.
2. Enter the required module specifications.

   Module description is an optional field you can use for the module name or other description.
3. Click **Calculate and plot**.

   After solving the module model equations, SAM displays a current-voltage (I-V) curve at STC.

Note. In some rare cases, SAM may not be able to find a solution for the set of specifications you provide. (It performs a series of internal checks that should ensure that it finds a solution in most cases.) If SAM displays an error message, first verify that the specifications you entered are correct. If the specifications are correct, you may be able to generate an I-V curve by making small adjustments to the specifications, such as slightly increasing the Isc value.

4. Under **Mounting Configuration**, choose the standoff height and array's height above ground.

Note. SAM's scripting language, SamUL, includes a function called Coeffgen6par() that you can use to automate the process of generating model coefficients from module specifications. For example,

```
result = coeffgen6par("monoSi", 30, 6, 36, 7, -0.43, 0.001, -0.1, 60)
OutLn( result )
```

Would display an array containing the six parameters a, Il, Io, Rs, Rsh, and Adjust, or the string "false" if the solution failed.

General Information

Module description

An optional string describing the module.

Cell type

A description of the semiconductor technology used in the photovoltaic cells. This parameter is used to guide the solution of normalized module coefficients, but is not directly used for power calculations once the coefficients are determined.

monoSi: Single-crystal silicon

multiSi: Multi-crystalline silicon

CdTe: Cadmium telluride

CIS: Copper indium diselenide

CIGS: Copper indium gallium sulfide

amorphous: Amorphous silicon

Module area, m²

The surface area of the entire module.

Nominal operating cell temperature, °C

The nominal operating cell temperature (NOCT) of the module is the measured cell temperature of the module at NOCT test conditions: 800 W/m² incident irradiance, 20 degrees Celsius ambient temperature, and 1 m/s wind speed. The mounting configuration under test conditions is typically open rack, except building-integrated (BIPV) modules which are tested in a building-integrated configuration.

Electrical Specifications

Maximum power point voltage (Vmp), V

The reference maximum power point voltage at STC.

Maximum power point current (Imp), A

The reference maximum power point current at STC.

Open circuit voltage (Voc), V

The open circuit voltage at STC.

Short circuit current (Isc), A

The short circuit current at STC.

Temperature dependence of Voc, V/°C or %/°C

The absolute change in Voc per degree change in temperature, also called alpha.

Temperature dependence of Isc, A/°C or %/°C

The absolute change in Isc per degree change in temperature, also called beta.

Temperature dependence of Pmp, %/°C

The percentage change in the maximum power point Pmp per degree change in temperature, also called gamma. To convert units from W/ºC to %/ºC, divide the %/ºC value by Pmp.

Number of cells in series

The number of cells wired together in series inside the module.

Mounting Configuration

SAM's CEC Performance Model with User Entered Specifications uses the NOCT Cell Temperature model from the CEC Performance Model with Module Database model.

Standoff height

The standoff height is the distance between the back of the module and surface of the roof for roof-mounted modules. For modules integrated with the building (BIPV), or for ground mounted modules, choose the appropriate option.

> **Note.** SAM does not make NOCT adjustments for the **Building integrated**, **Greater than 3.5 in**, or **Ground or rack mounted** options. For these options, the **Nominal operating cell temperature** value you provide should be at conditions appropriate for those types of installations.

Approximate installation height

SAM uses the installation height option to make an adjustment to the effect of wind speed on the cell temperature calculation. SAM assumes that an array with an installation height of one story or lower experiences lower wind speeds than those in the weather file because of the effect of nearby trees and structures. For the two story building or higher option, the wind is less impeded.

Nominal Maximum Power Ratings at STC

Power, Wdc

The module's rated maximum power point power at STC. This is equal to the product of the maximum power point voltage and maximum power point current.

Efficiency, %

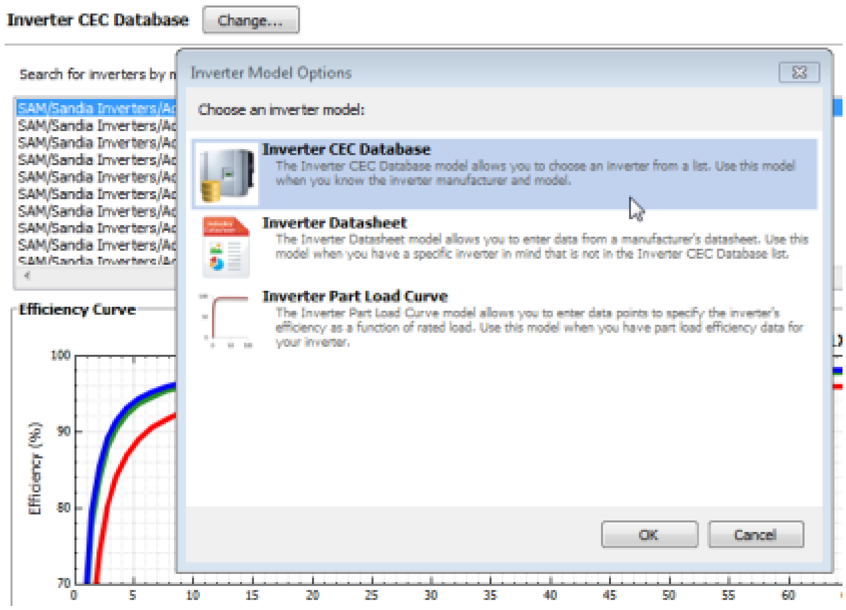
The module's rated efficiency at STC 1000 W/m² irradiance. SAM displays this value for reference only. During simulations, the model calculates an efficiency value for each hour, which you can see in the Tables on the Results page.

6.4.3 Inverter

The Inverter page allows you to choose an inverter performance model and either choose an inverter from a list, or enter inverter parameters from a manufacturer's data sheet using either a weighted efficiency or a table of part-load efficiency values.

SAM can only model a photovoltaic system with a single type of inverter. Specify the number of inverters in the system on the Array page.

SAM displays the name of the active inverter model at the top of the Inverter page. Click **Change** to choose a different model.



You can choose from three different inverter performance models:

- Inverter CEC Database calculates the system's AC output using parameters from SAM's CEC database of inverter parameters with the Sandia inverter model. To use this model, you simply choose an inverter from the list. Use this model for most analyses.
- Inverter Datasheet allows you to specify the inverter's parameters using values from a manufacturer's data sheet, and calculates coefficients for the Sandia inverter model from the parameters you provide. Use this model for an inverter that is not in the CEC database.
- Inverter Part Load Curve allows you to specify a table of part-load efficiency values for an inverter using data from a manufacturer's data sheet or other source. Use this model when you have the inverter's part-load efficiency data.

Each of the three inverter models calculates a DC to AC conversion efficiency, assuming that the DC power input to the inverter is equal to the derated DC output of the photovoltaic array. The inverter models limit the inverter's output to the inverter's Maximum AC Power parameter so that the inverter's output is "clipped" to this value. SAM uses the inverter Operating Ranges parameters to either size the system or display sizing suggestion messages on the Array page.

The inverter model reports several hourly simulation results on the Results page that you can use to understand how SAM models the inverter or to troubleshoot your analyses:

Gross ac output (kWh)

The inverter's AC output in kilowatt-hours before the interconnection derate factors from the Array page.

Inverter clipping loss (Wac)

The portion of the inverter's AC output not delivered to the grid during hours when the AC output exceeds the inverter's maximum AC output. During these hours, inverter's gross AC output is equal to the inverter's maximum AC output. SAM assumes that the system is designed to handle this excess electricity, but does not explicitly model the hardware required to do so.

Inverter dc input voltage (V)

The DC voltage at the inverter's input, equal to the array's DC string voltage. For systems with two or more subarrays, SAM estimates the inverter DC voltage as the average of the subarray string voltages.

Inverter efficiency (%)

The inverter's DC to AC conversion efficiency. The inverter efficiency is equal to the gross AC output divided by the net DC array output.

Inverter night time loss (Wac)

The amount of electricity consumed by the inverter at night when the array does not generate electricity. The night-time loss is equal to the value you specify for hours when the gross DC array output is zero. The night-time loss is zero for hours when the gross DC array output is greater than zero.

Inverter power consumption loss (Wdc)

The amount of electricity consumed by the inverter, not including the night-time loss. SAM estimates the hourly power consumption loss by adjusting the value you specify for Power consumption during operation based on the inverter's DC input voltage. The Inverter Part Load model assumes that the inverter's power consumption is accounted for in the part-load efficiency table that you specify, so it reports an inverter power consumption loss value of zero for all hours.

Net ac output (kWh)

The inverter's AC output, before the interconnection derate factors.

Contents

Inverter CEC Database

The Inverter CEC Database model is an implementation of the Sandia Model for Grid-Connected PV Inverters (Sandia inverter model). It is an empirically-based performance model of inverter performance that uses parameters from a database of commercially available inverters maintained by the California Energy Commission (CEC).

The Inverter CEC Database model consists of a set of equations that SAM uses to calculate the inverter's hourly AC output based on the DC input (equivalent to the derated output of the photovoltaic array) and a set of empirically-determined coefficients that describe the inverter's performance characteristics. The coefficients for each inverter are empirically determined from data provided by the inverter's manufacturer and either field measurements from an inverter of the same type installed in an operating photovoltaic system, or laboratory measurements. Measured values are taken using the CEC inverter test protocol.

The Sandia inverter model is described in King D et al (2007) *Performance Model for Grid-Connected Photovoltaic Inverters*, Sandia National Laboratories, SAND2007-5036, and on the PV Performance Modeling Collaborative website.

The CEC inverter test protocol is described in Bower W et al (Draft 2004) *Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems*, and on the PV Performance Modeling Collaborative website.

Note. SAM stores the list of inverters for the Inverter CEC Database model in the Sandia Inverter library. The library contains parameters for inverters in the List of Eligible Inverters per SB1 Guidelines at http://www.gosolarcalifornia.org/equipment/inverters.php. We try to keep the library as current as possible, but there may be periods when SAM's library is out of date. If the library appears to be out of date, you can check for updates by clicking **Check for updates to this version** on the Help menu.

You can export the entire Sandia inverter library as a comma-separated values (CSV) text file from SAM's library editor. To open the library editor, on the Tools menu, click **Library Editor**.

If you are an inverter manufacturer and would like to add your inverter to the list, you should contact the California Energy Commission (CEC) or Sandia National Laboratories directly. For information about the Sandia Test and Evaluation program, see http://energy.sandia.gov/?page_id=279. For a list of Sandia contacts, see http://energy.sandia.gov/?page_id=2772. For CEC contacts, see http://www.gosolarcalifornia.ca.gov/equipment/add.php.

To use the Inverter CEC Database model:

1. On the Inverter page, click **Change** and choose **Inverter CEC Database**.
2. Choose an inverter from the list of available inverters. You can type a few letters of the manufacturer or inverter name in the Search box to filter the list.

   If you are modeling an inverter not included in the database and want to use the Sandia inverter model, you can use the Inverter Datasheet model with values from a manufacturer's data sheet.

Each inverter listing shows the manufacturer name, model number and AC voltage rating, and information in brackets about the organization responsible for generating the test data and the year the data was generated. "CEC" indicates that test data was generated by the California Energy Commission.

Efficiency Curve and Characteristics

When you select an inverter from the list, SAM displays an efficiency curve and the inverter's parameters for your reference. The parameter values are from the Sandia inverter library, and are values that the Sandia inverter model uses as inputs.

Note. SAM displays a few of the parameters from the CEC database on the Inverter page. If you want to see the complete set of parameters, you can do so in the library editor.

Weighted Efficiency, %

SAM calculates and displays both the CEC weighted efficiency and European weighted efficiency for your reference. It does not use these efficiency values during simulations. To calculate the efficiencies, SAM calculates the inverter's nominal efficiency at seven different power levels, and applies the set of weighting factors for the CEC and European methods of calculating the weighted efficiency.

The following list briefly describes the each parameter that SAM displays on the Inverter page. You can read more about these and all of the other Sandia inverter model input parameters in the King 2004 reference cited above. The names in brackets are the names used in the King reference.

Maximum AC power [Power ACo], Wac

Maximum output AC power at reference or nominal operating conditions. Available from manufacturer specifications.

Maximum DC power [Power DCo], Wdc

Input DC power level at which the inverter's output is equal to the maximum AC power level. Available from manufacturer specifications.

Power consumption during operation [PowerSo], Wdc

DC power required for the inverter to start converting DC electricity to AC. Also called the inverter's self-consumption power. Sometimes available from manufacturer specifications, and not to be confused with the nighttime AC power consumption.

Power consumption at night [PowerNTare], Wac

AC power consumed by the inverter at night to operate voltage sensing circuitry when the photovoltaic array is not generating power. Available from manufacturer specifications.

Nominal AC voltage [AC Voltage], Vac

Rated output AC voltage from manufacturer specifications.

Maximum DC voltage [Vdcmax], Vdc

The inverter's maximum DC input voltage.

Maximum DC current [Idcmax], Adc

The maximum DC voltage input, typically at or near the photovoltaic array's maximum power point current.

Minimum MPPT DC voltage [MPPT-low], Vdc

Manufacturer-specified minimum DC operating voltage, as described in CEC test protocol (see reference above).

Nominal DC voltage [Vdco], Vdc

The average of MPPT-low and MPPT-high, as described in the CEC test protocol (see reference above).

Maximum PPT DC voltage [MPPT-hi], Vdc

Manufacturer-specified maximum DC operating voltage, as described in CEC test protocol (see reference above). The test protocol specifies that the inverter's maximum DC voltage should not exceed 80% of the array's maximum allowable open circuit voltage.

The four coefficients C0..C3 are empirically-determined coefficients that are inputs to the Sandia inverter model. Manufacturers do not provide these coefficients on inverter datasheets.

C0, 1/V

Defines the relationship between AC and DC power levels at the reference operating condition.

C1, 1/V

Defines the value of the maximum DC power level.

C2, 1/V

Defines the value of the self-consumption power level.

C3, 1/V

Defines the value of Coefficient C0.

Inverter Datasheet

The Inverter Datasheet model is an implementation of the Sandia Model for Grid-Connected PV Inverters that allows you to model an inverter by entering data from a manufacturer's data sheet.

The Inverter Datasheet model consists of a set of equations that SAM uses to calculate the inverter's hourly AC output based on the DC input (equivalent to the derated output of the photovoltaic array) and a set of coefficients that describe the inverter's performance characteristics. SAM calculates the coefficients from the manufacturer data you provide.

Note. If you have a table of part-load efficiency values for the inverter, you may want to use the Inverter Part Load Curve model instead of the Inverter Datasheet model.

To use the Inverter Datasheet model:

On the Inverter page, click **Change**, and choose **Inverter Datasheet**.

- Enter input values from the manufacturer's data sheet. See below for descriptions of the inputs.

Power Ratings

Maximum AC output power

The inverter's rated maximum AC output in Watts. Manufacturers may use different names for this value, such as continuous output power, rated active power, peak output, etc.

Weighted efficiency and Manufacturer efficiency

Inverter manufacturers provide different efficiency ratings on their product data sheets. SAM can model the inverter using either a weighted efficiency or a nominal efficiency. If the manufacturer provides a weighted efficiency, you should use it rather than the nominal efficiency. The weighted efficiency more accurately reflects the inverter's performance under different operating conditions.

If you choose **Weighted efficiency**, you can use the weighted efficiency calculated with either the European or CEC method. The European method is best for locations with lower solar resource where the inverter operates more often at lower load levels. The CEC method is best for sunnier locations where the inverter operates at higher load levels. See Inverter Efficiency Values for more details.

If you choose **Nominal efficiency**, you can use either a peak efficiency or another efficiency value from the data sheet that represents the inverter's efficiency at a single load level. You should also specify a value for **Power consumption during operation** to improve the accuracy of the model at low power levels.

Maximum DC input power

SAM calculates and displays the equivalent rated DC input capacity based on the maximum AC output power and efficiency value that you specify (either weighted or nominal):

Maximum DC Input Power (Wdc) = Maximum AC Output Power (Wac) ÷ Efficiency (%) × 100%

SAM uses the maximum DC input power value to size the array when you choose **Specify desired array size** on the Array page, and to display sizing messages when you choose **Specify modules and inverters**.

Operating Ranges

SAM uses the operating range variables to help you size the system on the Array page.

Nominal AC operating voltage

The inverter's nominal AC output voltage.

Maximum DC voltage

The inverter's maximum input DC voltage.

Maximum DC current

The inverter's maximum input DC current.

Minimum MPPT DC voltage

The inverter's minimum DC operating voltage.

Nominal DC voltage

The inverter's nominal DC operating voltage.

Maximum MPPT DC voltage

The inverter's maximum DC operating voltage.

Losses

The two loss variables account for electricity consumed by inverter components during operation and to keep the inverter in standby mode at night when the array is not generating electricity.

When you specify the inverter's efficiency using a weighted efficiency, you only need to specify a value for the night-time power consumption because the weighting factors account for the power consumption during operation.

SAM displays a suggested value for each loss variable, which is based on an analysis of the loss parameters for the inverters in the SAM 2013.1.5 CEC library, and should be a reasonable approximation for inverters currently available on the market. If the manufacturer does not provide values for the inverter's power consumption, you can use the suggested value. (You must type the value in the input box, SAM does not automatically assign the suggested value to the variable.)

Power consumption during operation

Electricity consumed by the inverter during the day when the photovoltaic array is generating power. SAM disables this variable when you specify a weighted efficiency.

SAM calculates the suggested value using the following equation:

Suggested Value for Consumption during Operation (Wdc) = 0.8% × Maximum AC Output Power (Wac)

Power consumption at night

Electricity consumed by the inverter during the night when the photovoltaic array is not generating power. This value is sometimes also called tare loss or standby loss.

SAM calculates the suggested value using the following equation:

Suggested Value for Consumption at Night (Wac) = 0.25% × Maximum AC Output Power (Wac)

Inverter Part Load Curve

The Inverter Part Load Curve model allows you to model an inverter by entering part-load efficiency and other data from a manufacturer's data sheet. Unlike the CEC Database and Inverter Datasheet inverter models, this model is not based on the Sandia inverter model. Instead, it determines the inverter's hourly conversion efficiency based on the part-load efficiency data points and night-time loss values you provide.

Note. If you do not have a table of part-load efficiency values for the inverter, you may want to use the Inverter Datasheet model instead of the Part Load Curve model.

To use the Inverter Part Load Curve model:

1. On the Inverter page, click **Change**, and choose **Inverter Part Load Curve**.
2. Type a value for the **Maximum AC output power**, and choose **CEC efficiency** or **European efficiency**.
3. Type values for the **Operating Ranges** input variables and for **Power consumption at night loss**.
4. Type values in the part-load efficiency table and for the operating range input variables.

   See below for descriptions of the variables, and more detailed instructions for working with the part-load efficency table.

Power Ratings

Maximum AC output power

The inverter's rated maximum AC output in Watts. Manufacturers may use different names for this value, such as continuous output power, rated active power, peak output, etc.

CEC efficiency and European efficiency

Specify the inverter's weighted efficiency calculated with either the European or CEC method. The European method is best for locations with lower solar resource where the inverter operates more often at lower load levels. The CEC method is best for sunnier locations where the inverter operates at higher load levels. See Inverter Efficiency Values for more details.

Maximum DC input power

SAM calculates and displays the equivalent rated DC input capacity based on the maximum AC output power and efficiency value that you specify (either weighted or nominal):

Maximum DC Input Power (Wdc) = Maximum AC Output Power (Wac) ÷ Efficiency (%) × 100%

SAM uses the maximum DC input power value to size the array when you choose **Specify desired array size** on the Array page, and to display sizing messages when you choose **Specify modules and inverters**.

Operating Ranges

SAM uses the operating range variables to help you size the system on the Array page.

Nominal AC operating voltage

The inverter's nominal AC output voltage.

Maximum DC voltage

The inverter's maximum input DC voltage.

Maximum DC current

The inverter's maximum input DC current.

Minimum MPPT DC voltage

The inverter's minimum DC operating voltage.

Nominal DC voltage

The inverter's nominal DC operating voltage.

Maximum MPPT DC voltage

The inverter's maximum DC operating voltage.

Losses

The two loss variables account for electricity consumed by inverter components to keep the inverter in standby mode at night when the array is not generating electricity.

Power consumption at night

Electricity consumed by the inverter during the night when the photovoltaic array is not generating power. This value is sometimes also called tare loss or standby loss.

Part Load Efficiency

SAM uses the part-load efficiency table you specify to determine the inverter's efficiency during simulations. You can either type values in the table by hand, import values to the table from a properly formatted text file, or paste data to the table from your computer's clipboard.

SAM uses linear interpolation to calculate efficiency values for output power levels between the points in the table. If you specify only a single row, SAM assumes that the inverter's efficiency is constant over its full output power range.

Tips for working with the part-load efficiency table:

- To clear the table, change **Rows** to 1, and then change it to the number of rows in your data set.
- Double click a cell to select it.
- Use the Tab and Shift-Tab keys to move between columns.
- Use the Enter key to move down a column.
- If you type a non-numeric character, SAM replaces the character with a zero.

To specify the part-load efficiency curve using the table:

1. Under Rows, type the number of data points you want to include in the table. You must specify at least one row of values in the table.
2. For each row in the table, type a value for output power as a percentage of the inverter's rated capacity, and a DC to AC conversion efficiency value as a percentage.

   SAM displays the part-load efficiency curve in the plot area as you type values in the table.

To import part-load efficiency data from a text file:

1. Prepare a text file of comma-separated values. The file should have one line for each output-efficiency value pair separated by a comma with no header rows. For example:

   0,0

   10,96.1

   20,97.55

   30,97.87

   ...

   The output percentages should increase from the first row to the last, but not necessarily in equal increments.

   You can also export the efficiency data from the default flat plate photovoltaic case to see an example of what the file should look like.

2. Click **Import**.

   SAM populates the part-load efficiency table with data from the file.

To paste part-load efficiency data from your computer's clipboard:

1. Prepare a spreadsheet file or text file with one row for each output-efficiency pair, and output and efficiency values in separate columns or separated by a tab.
2. In your spreadsheet program or text editor, select the two columns containing the data. Do not include column headings or other labels or data.
3. In SAM, on the Inverter page under **Part Load Efficiency**, click **Paste**.

   SAM populates the part-load efficiency table with data from the clipboard.

Weighted and Manufacturer Efficiency Values

When you use either the Inverter Datasheet model or the Inverter Part Load Curve model, you must provide SAM with an efficiency value that determines the invereter's maximum DC input power that SAM uses for sizing the photovoltaic array.

Inverter manufacturers often show several efficiency values on an inverter's datasheet. Weighted efficiency values are more accurate representations of an inverter's efficiency over a range of output levels than an efficiency value at a single operating point.

Many inverter data sheets will show two versions of the weighted efficiency value: The CEC weighted efficiency, or the European weighted efficiency. The table below shows the weighting factors used to determine both versions of the weighted efficiency. In general, you should use the CEC weighted efficiency to model a system in a sunny location, and you should use the European weighted efficiency for less sunny locations. The following equation shows how the weighted efficiency is calculated, where ηweighted is the weighted efficiency value, F1..F7 are shown in the table below, and η5, η10... are the inverter part-load efficiencies at 5%, 10%… of maximum AC output:

$$\eta weighted = F1 \times \eta 5 + F2 \times \eta 10 + F3 \times \eta 20 + F4 \times \eta 30 + F5 \times \eta 50 + F6 \times \eta 75 + F7 \times \eta 100$$

Weighting Factors for CEC and European Weighted Inverter Efficiencies

Percent of Inverter Maximum AC Output	Factor	CEC Weighting Factor	European Weighting Factor
5	F1	0.00	0.03
10	F2	0.04	0.06
20	F3	0.05	0.13
30	F4	0.12	0.10
50	F5	0.21	0.48
75	F6	0.53	0.00
100	F7	0.05	2.00

6.4.4 Array

The Flat Plate PV model's Array page displays variables and options that specify the number of modules and inverters in the system, AC derate factors, and land area. You can also use the Array page to choose options for how SAM handles weather data, and to model array self-shading. SAM uses the array properties to calculate the array's DC output and the system's AC output.

> **Notes.**
>
> See Sizing Messages for a description of the messages that appear under **Specify System Size**.
>
> Before specifying parameters on the Array page, you should specify the module characteristics on the Module page, and the inverter characteristics on the Inverter page.
>
> After specifying Array parameters, specify the array tracking and orientation, shading and soiling factors, and DC derate factors on the PV Subarrays page.

Layout

The Layout variables determine the number of modules in the system, string configuration, and number of inverters in the system.

SAM considers the system's nameplate capacity to be the photovoltaic array's size in DC kW.

See Sizing the PV System for step-by-step instructions.

> **Note.** Choosing an appropriate module and inverter for your system depends on many factors, some of which are outside of the scope of SAM. Finding the right combination of inverter and module to model for your system in SAM will probably require some trial and error and iteration.

Specify System Size

SAM provides two options for specifying the system size:

- **Specify desired array size** allows you to type a desired value for the system nameplate capacity and a DC-to-AC ratio, and SAM calculates the number of modules and inverters to get as close as possible to the desired size. Use this option for a rough estimate of an array layout.
- **Specify numbers of modules and inverters** allows you to specify the number of modules per string, strings in parallel, and number of inverters in the system. Use this option to model a specific array layout.

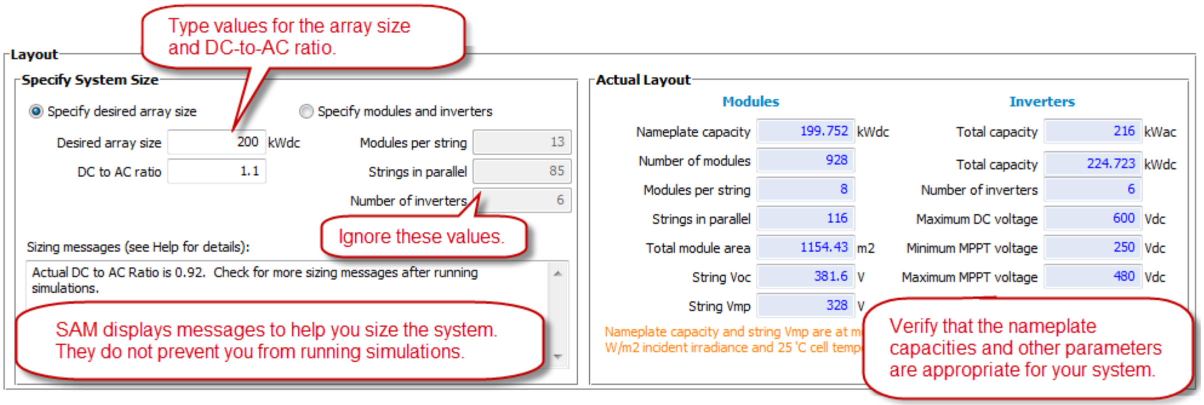
Option 1: Specify desired array size

For **Desired Array Size**, type the DC capacity, and for **DC to AC Ratio**, type the ratio of nameplate capacity (DC kW) to total inverter capacity (AC kW) you want for your system. SAM determines the number of modules and inverters required to get as close as possible to the desired size using the module and inverter properties from the Inverter and Module pages.

If the resulting nameplate capacity under **Actual Layout** is not suitable for your analysis, you may need to choose a different module or inverter.

See Sizing the PV System for step-by-step instructions.

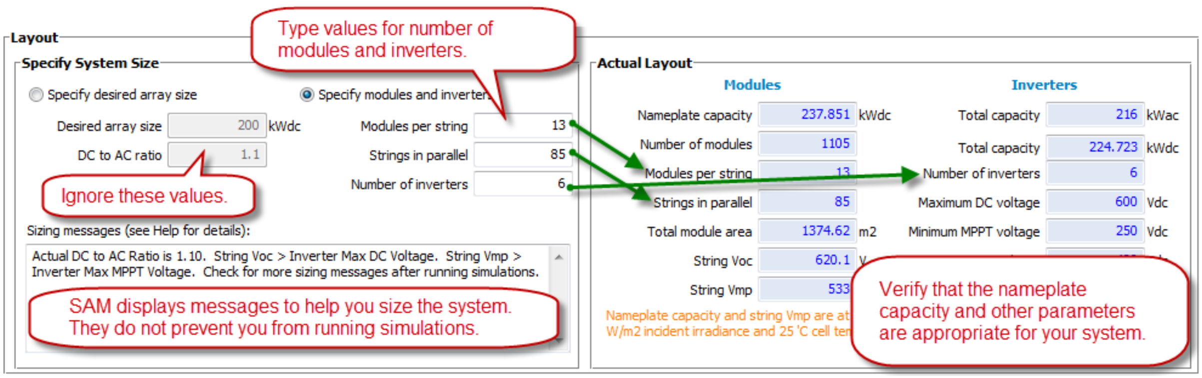
Note. The desired array size and DC to AC ratio is likely to be different from the actual Nameplate capacity and DC to AC ratio because the desired array size is typically not an even multiple of the module capacity.



Option 2: Specify numbers of modules and inverters

Type values for **Modules per String**, **Strings in Parallel**, and **Number of Inverters**. Verify that the nameplate capacity and other parameters under **Actual Layout** are reasonable for the system you are simulating.

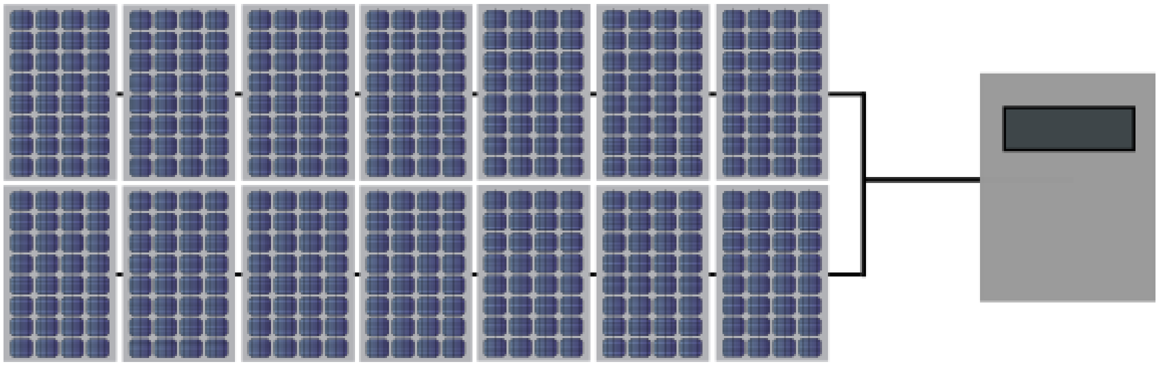
See Sizing the PV System for step-by-step instructions.



About Numbers of Modules and Inverters

The **Modules per string**, **Strings in parallel**, and **Number of inverters** input variables determine the number of modules and inverters in the system. As described above, you can either specify the values yourself, or specify a desired size so that SAM calculates the values for you.

For example, the line diagram for a system with 7 modules per string, 2 strings in parallel, and 1 inverter would look like this:



Modules per string

The number of modules connected in series in a single string. SAM assumes that all strings in the array have the same number of modules connected in series, even when the array consists of multiple subarrays.

The number of modules per string determines the array's open circuit voltage (**String Voc**) and maximum power rated voltage (**String Vmp**).

For most analyses, you should ensure that **String Voc** is less than the inverter **Maximum DC voltage**. If the inverter does not have a value for the maximum DC voltage, you can find the value on inverter manufacturer's data sheet, which you may be able to find on the manufacturer or equipment supplier website.

Similarly, you should ensure that **String Vmp** is between the inverter **Minimum MPPT voltage** and **Maximum MPPT voltage**.

Note. If you are using a module from the Sandia database on the Module page with the word "array" in its name, the module represents an array, so the Modules per String variable represents the number of arrays in the system rather than number of modules.

Strings in parallel

The number of strings of modules connected in parallel to form the array. Once you specify the number of modules per string to determine the array's string voltage, the number of strings in parallel determines the array's nameplate DC capacity in kilowatts.

Number of inverters

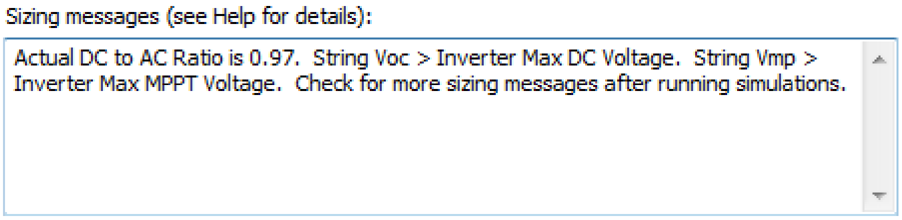
The total number of inverters in the system, which determines the total inverter capacity. SAM assumes that all inverters in the system are connected in parallel so that the inverter bank's rated voltage limits are the same as those of a single inverter. The current version of SAM does not model string inverters with different voltages.

Note. If you are modeling a system with microinverters, see Modeling Microinverters for instructions.

Sizing Messages

As you type values to determine the array layout, SAM displays messages to help you ensure that the DC-to-AC ratio is close to your target value, and that the nominal string voltages are within the inverter rated voltage limits. These messages are based on the module and inverter rated voltages from the manufacturer data sheets, not on operating voltages. After running simulations, you can check the operating voltages to refine your system design. See Size the PV Array by Hand for instructions.

The sizing messages do not prevent you from running simulations.



The sizing messages display the following information:

- DC to AC ratio based on the array and inverter capacities:

  Actual DC to AC Ratio = Total Nameplate Array Capacity in DC kW ÷ Total Nameplate Inverter Capacity in DC kW × 100%

- Array string open circuit voltage exceeds inverter maximum DC voltage:

  String Voc > Inverter Maximum DC Voltage

- Array string maximum power voltage exceeds the inverter maximum MPPT voltage:

  String Vmp > Maximum Inverter MPPT Voltage

- Array string maximum power voltage is less than the inverter minimum MPPT voltage:

  String Vmp < Minimum Inverter MPPT Voltage

Actual Layout

SAM calculates the values under **Actual Layout** based on the values you specify under **Specify System Size**, and from values on the Module and Inverter page. Use these values to verify that the array is correctly configured.

> **Note.** You cannot edit the Actual Layout values. To change the values, you must edit values under **Specify System Size**, or on the Module or Inverter pages.

Modules

Nameplate capacity, kWdc

The maximum DC power output of the array at the reference conditions shown on the Module page:

Nameplate Capacity (kWdc) = Module Maximum Power (Wdc) × 0.001 (kW/W) × Total Modules

The module's maximum power rating is from the Module page. The number of modules is the value listed under **Actual Layout**.

Number of modules

The number of modules in the array:

Total Modules = Modules per String × Strings in Parallel

The numbers of modules and strings are the values listed under **Actual Layout**.

Modules per string

The number of modules per string.

Strings in parallel

The number of strings of modules in the array.

Total module area, m²

The total area in square meters of modules in the array, not including space between modules:

Total Area (m²) = Module Area (m²) × Number of Modules

The module area is shown on the Module page. The number of modules is the value listed under **Actual Layout**.

String Voc, Vdc

The open circuit DC voltage of each string of modules at 1000 W/m2 incident radiation and 25°C cell temperature:

String Voc (Vdc) = Module Open Circuit Voltage (Vdc) × Modules per String

The module open circuit voltage and reference conditions are from the Module page. The number of modules per string is the value listed under **Actual Layout**.

String Vmp, Vdc

The maximum power point DC voltage of each string of modules at the module reference conditions shown on the Module page:

String Vmp (Vdc) = Module Max Power Voltage (Vdc) × Modules per String

The module's maximum power point voltage is at reference conditions as specified on the Module page. The number of modules per string is the value listed under **Actual Layout** under **Array sizing**.

SAM displays a maximum power point voltage of zero for the simple efficiency module performance model because the model does not include voltage ratings.

Note. For the Sandia and CEC module models on the Module page, the open circuit and maximum power voltages are at 1,000 W/m² incident radiation and 25ºC cell temperature. For the simple efficiency module model, SAM displays a zero for both values because the model does not include voltage ratings.

Inverters

Total capacity, kWac

The total inverter capacity in AC kilowatts:

Inverter Total Capacity (kWac) = Inverter Maximum AC Power (Wac) × 0.001 (kW/W) × Number of Inverters

The inverter's nominal AC power rating is from the Inverter page. The number of inverters is the value listed under **Actual Layout**.

Number of inverters

The number of inverters in the system.

Maximum DC voltage, Vdc

The inverter's maximum rated input DC voltage from the Inverter page.

For systems with more than one inverter, SAM assumes that inverters are connected in parallel so that the rated voltages of the inverter bank are the same as those of a single inverter.

Minimum MPPT voltage and **Maximum MPPT voltage, Vdc**

The inverter minimum and maximum operating voltages, as specified by the manufacturer, from the Inverter page.

Note. When SAM displays zero for the inverter voltage limits, you should refer to the inverter data sheet for those values and make sure that array string Voc does not exceed the inverter's maximum DC voltage. SAM displays a value of zero for inverters in the CEC library for which there is not a value in the database.

Interconnection Derates (AC)

The interconnection derate factors account for losses in the system that the inverter model does not account for, such as electrical losses in AC wiring that connects the inverter to the grid and any external power conditioning equipment.

During simulations, SAM uses the interconnection derate factors you specify to reduce the inverter AC electric output calculated by the inverter model.

You can see the effect of the interconnection derate factors in the hourly results (and in the monthly and annual averages) in the Tables on the Results page. In the hourly results:

Net AC Output = Gross AC Output × Total Interconnection Derate

Note. SAM applies additional factors to the net AC output to calculate the system's delivered net AC output based on the values you specify on the Performance Adjustment page.

AC wiring losses

Derate factor to account for electrical losses in AC wiring between the inverter and the grid connection point.

Step-up transformer losses

Derate factor to account for transformer electrical losses.

Total interconnection derate

The product of the two AC derate factors.

In the hourly simulation, SAM calculates the net AC power for each hour by multiplying the inverter's gross AC output by the total interconnection derate factor. A derate factor of 1 is equivalent to no derating. A derate factor of 0.75 would reduce the gross AC output by 25%.

Ground Reflectance

SAM uses the ground reflectance value (also called albedo) to make a small adjustment to the amount of radiation incident on the array to represent radiation reflected onto the array from the ground. For most analyses, you can use the default value of 0.2 assigned to each month.

After running simulations, you can see the albedo value that SAM uses for simulations on the Results page in Tables under Hourly Data or in the Time Series data viewer.

Use albedo in weather file if it exists

Check this option if you want SAM to use albedo data from the weather file you specify on the Location and Resource page instead of the **Monthly Ground Reflectance (albedo)** values.

For each time step in the simulation, SAM checks the value in the albedo column of the weather file to see if it is between zero and one. If it is within that range, SAM uses that value for the albedo in that hour. If the value in the weather file is outside of that range for a given hour, then SAM uses the appropriate **Monthly Ground Reflectance (albedo)** input value for that hour.

For the standard TMY2 and TMY3 weather files from the National Solar Radiation Database (NSRDB), only some of the TMY3 files contain albedo values.

Monthly Ground Reflectance (albedo)

The ground reflectance value by month. The default value is 0.2, which is reasonable for grassy ground. A value of 0.6 would be reasonable for snow-covered ground.

A value of zero means that the ground is completely non-reflective, and a value of 1 means that it is completely reflective.

To see the monthly ground reflectance values, click **Edit Values.** To change the values, type a value for each month that you want to change. During simulations, SAM applies the albedo value that you specify for a given month to each hour of that month.

Land Area

Packing Factor

The packing factor is a multiplier that makes it possible to estimate the land area required by a project based on the total module area of the array.

Note. The packing factor only has an effect on simulation results when you specify land costs in $/acre on the the PV System Costs page.

Total Land Area

The total land area is an estimate of the land area required by the PV system:

Total Land Area = Total Area (m²) × Packing Factor ÷ 4,047 (m²/acre)

Tilted Surface Radiation Model (Advanced)

Note. The radiation model and tilt radiation type options are for advanced users. Use the default **Beam and Diffuse** and **Perez Model** options unless you have a reason to change them.

SAM allows you to choose the method it uses to convert global horizontal solar radiation data to global solar radiation incident on the array. Each method uses information about the global horizontal solar radiation and either the direct normal or diffuse solar radiation, and about the sun's position and orientation of the array. The four methods differ in how they estimate the diffuse radiation incident on the array.

The isotropic model tends to under-predict the global radiation on a tilted surface, and is included as an option for analysis wanting to compare SAM results with those from other models using this approach. The remaining three methods provide comparable estimates of the incident global radiation.

For references describing the different radiation models, see References, Weather Data.

Isotropic

Assumes that diffuse radiation is uniformly distributed across the sky, called isotropic diffuse radiation.

HDKR

Accounts for the increased intensity of diffuse radiation in the area around the sun, called circumsolar diffuse radiation, in addition to isotropic diffuse radiation.

Perez

The Perez method is the default value and is best for most analysis.

Accounts for horizon brightening, circumsolar and isotropic diffuse radiation using a more complex computational method than the Reindl and Hay and Davies methods.

Radiation Components

The Radiation Components options determine how SAM uses the global horizontal radiation, direct normal radiation, and diffuse horizontal radiation data from the weather file in radiation calculations.

Beam and Diffuse

This is the default option, and is best for most analyses. SAM reads the direct normal radiation (beam) and diffuse horizontal radiation data, and ignores the global horizontal radiation data from the weather file. SAM calculates the global incident radiation.

Total and Beam

SAM reads the global horizontal radiation (total) and direct normal radiation (beam) data, and ignores the diffuse horizontal radiation from the weather file. SAM calculates the diffuse incident radiation.

Self Shading Calculator for Fixed Tilt Arrays

The self-shading model estimates the reduction in the array's DC output due to row-to-row shading of modules within the array, where shadows from modules in neighboring rows of the array block sunlight from parts of other modules in the array during certain times of day.

Important Note!

The self shading model only works for Subarray 1 on the PV Subarrays page with fixed tracking. If you run simulations with more than one subarray, self-shading applies only to Subarray 1.

If you try to run simulations with self-shading and 1 Axis, 2 Axis or Azimuth Axis tracking for Subarray 1, SAM will generate a simulation error. To model shading for those tracking options, use the input variables on the PV Subarrays page.

The response of a real photovoltaic module to shading is complex, and depends on several factors including the cell material, shape and layout of cells in the module, and configuration of bypass diodes in the module.

For a description of the self-shading model implemented in SAM, see the pre-print of the forthcoming article in *Progress in Photovoltaics*: C. Deline, A. Dobos, S Janzou, J. Meydbrey, M. Donovan. *A simplified model of uniform shading in large photovoltaic arrays* (PDF 1.3 MB).

SAM's self-shading model has several limitations, and only works under the following conditions:

- The performance model is Flat Plate PV. The self-shading model is disabled for the PVWatts modeling option because the model requires information about modules and inverters that is not available with PVWatts.
- The cell material is crystalline silicon, either mono-crystalline or poly-crystalline. The self-shading model does not work for modules with thin film cells. SAM indicates the cell material on the Module page under Physical Characteristics.
- Each module in the array consists of square cells arranged in a rectangular grid with one or more bypass diodes and can be described using the input variables described below. The self-shading model does not work for modules with rectangular, circular, or triangular shaped cells.
- The array uses the fixed tracking option on the Array page. The self-shading model does not work for one-axis, two-axis, or azimuth-axis tracking.

- The the number of modules per string and strings in parallel specified on the Array page is consistent with the corresponding values you specify for self shading.

> **Note.** To use the self-shading model, you need information about the module's dimensions, cell layout, and number of bypass diodes. This information is not available in SAM, but you should be able to find it on the manufacturer's data sheet for the module.

SAM's module performance models assume that modules operate at the maximum power point for the level of incident radiation in each hour. The self-shading model calculates a single derating factor for each that estimates the total effect of shading on the array's output. The self-shading model calculates and applies the hourly DC derating factors using the following algorithm:

1. Calculate the array's derated DC output (without shading) at the maximum power point based on the inputs you specify on the Module page and Array page.
2. Calculate the size and position of rectangles of shade on the array using information about the relative positions of the sun and modules in the array.
3. Determine the reduction in output of each module in the array based on the number of shaded cells and bypass diodes.
4. Calculate an overall derate factor to apply to the array's maximum power point DC output that represents the reduction of output caused by the shadows.
5. Recalculate the array's derated DC output.

Module

The module input variables describe the properties of the module required by the self-shading model. Note that the values of these variables should be consistent with those shown on the Module page.

Orientation

The module orientation determines whether the short or long side of the module is parallel to the ground, assuming that all modules in the array are mounted at a fixed angle from the horizontal equal to the tilt angle specified on the Array page.

Portrait orientation means the short end of the module is parallel to the ground, or at the bottom of the module.

Landscape orientation means the long end of the module is parallel to the ground, or at the bottom of the module.

Length

Long side of a module in meters. SAM calculates this value based on the width (short side) you specify and area from the Module page (shown under **Characteristics from Module Page**).

Length (m) = Module Area (m^2) ÷ Width (m)

Width

Short side of a module in meters. You should be able to find this value on the manufacturer data sheet.

Number of cells along length

The number of cells along the long side of the module. SAM calculates this value based on the number of cells along width that you specify and the number of cells from the Module page (shown under **Characteristics from Module Page**). You should verify that the number of cells on the Module page is consistent with the number shown on the manufacturer data sheet.

Number of Cells Along Length = Number of Cells ÷ Number of Cells Along Width

Note. If you use the Simple Efficiency Model option on the Module page, SAM assumes a number of cells of 60.

Number of cells along width

The number of cells along the short side of the module. You should be able to find this value on the manufacturer's data sheet.

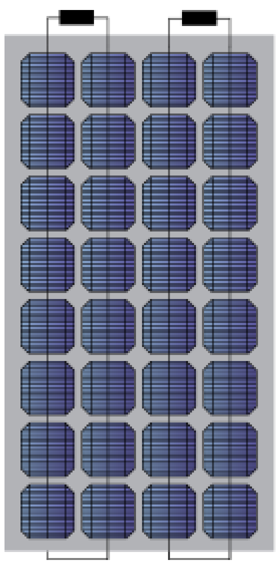
Number of bypass diodes

The number of bypass diodes in each module. Here are some typical bypass diode configurations:

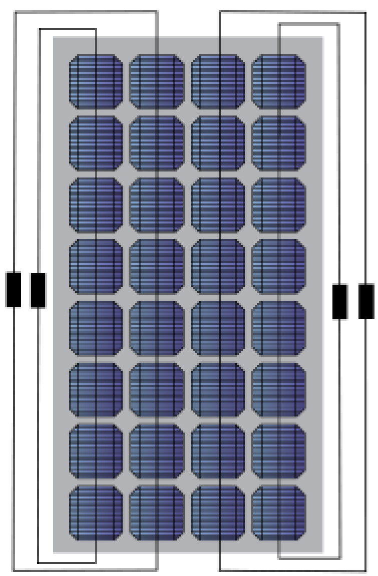
- All crystalline silicon modules include bypass diodes at a minimum in the junction box to prevent hot-spot damage from partial shading, typically one diode per 20-24 cells (3-4 diodes per module).
- Amorphous silicon module, such as Unisolar, typically include one bypass diode per cell.
- Thin-film modules with thin cells that provides built-in shade tolerance, such as First Solar, have no bypass diodes. This requires an array layout that results in little or no shading of modules.

The images below show examples of a module with four cells along its width and in portrait orientation. Because the module is in portrait orientation, SAM would consider it to have four cells along the bottom of the module, and would assume the diode connections shown in the diagrams for the module with two, four, and eight diodes.

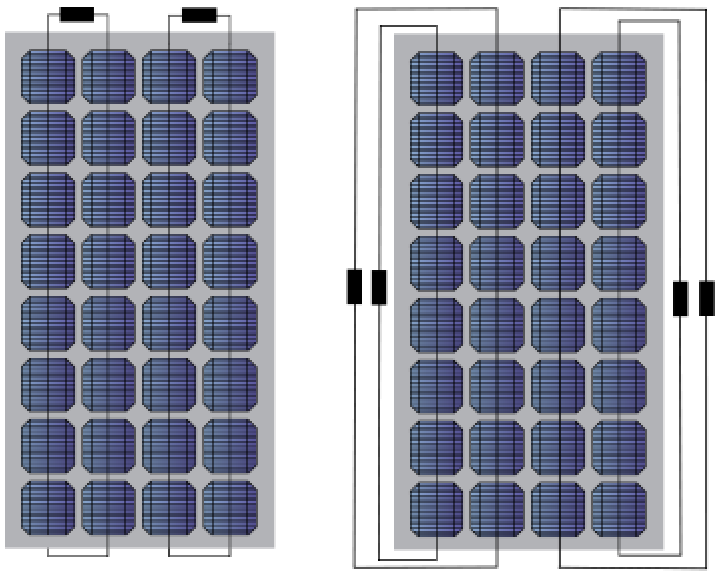
Note. SAM only uses the diode connections to estimate the DC power output reduction of the array due to shading. The model does not consider diode polarity or current flow through the modules.



4 cells, 2 diodes

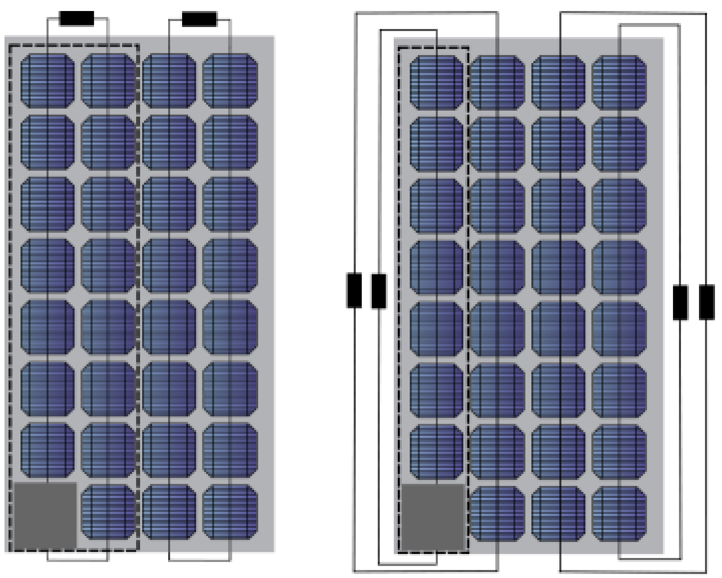


4 cells, 4 diodes



4 cells, 2 diodes   4 cells, 4 diodes

The number of diodes determines what portion of the module output is reduced. In the following images, the grey square indicates the shaded cell for each of the combinations of numbers of diodes, and rectangle with broken lines indicates the portion of the module affected by the shaded cell. For example, for a module with four cells along the bottom and two diodes, when any single cell is shaded, SAM reduces the module's power output by 50%.



4 cells, 2 diodes
50% shaded

4 cells, 4 diodes
25% shaded

Characteristics from Module Page

SAM displays the module area and number of cells for your reference.

Note. If you use the Simple Efficiency Model option on the Module page, SAM assumes a number of cells of 60.

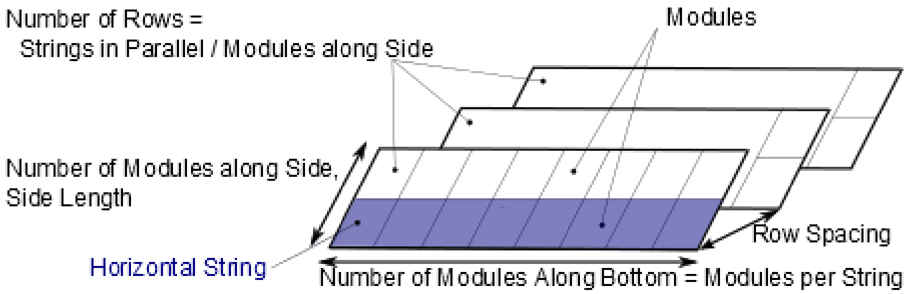
Array

The array input variables describe how modules are oriented in the array, and should be consistent with the values specified on the Array page.

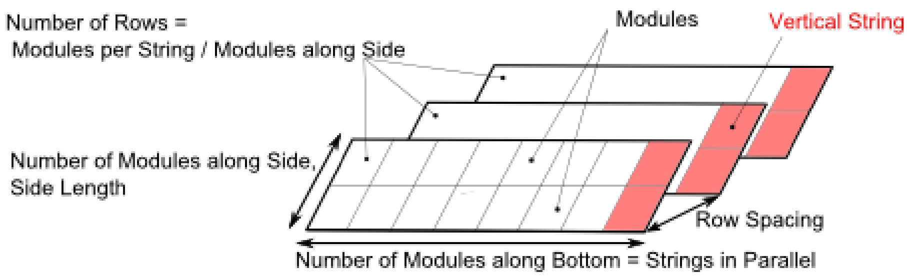
String Wiring

Describes the orientation of strings of modules in the array.

Horizontal Strings are parallel to the ground (the diagram shows modules in portrait orientation):



Vertical: Strings are inclined at the array's tilt angle (the diagram shows modules in portrait orientation):



Number of strings along bottom

The number of strings (as defined on the Array page) along the bottom of a row.

This option is only available for horizontal string wiring.

Number of modules along bottom

The number of modules along the bottom of a row.

This is a calculated value that you cannot edit. The value depends on the string wiring option and the number of modules per string or strings in parallel from the Array page.

For horizontal string wiring:

*Number of Modules Along Bottom = Modules per String * Number of Strings Along Bottom*

For vertical string wiring:

Number of Modules Along Bottom = Strings in Parallel

Number of modules along side

The number of modules along the edge of the array perpendicular to the bottom of the array as defined above.

SAM uses the number of modules along side to calculate the number of rows. Be sure to specify a value that makes sense given the division shown below.

Side Length

The length of a row in meters of modules in the plane inclined at the array tilt angle. The equation depends on module orientation.

For portrait:

Side Length = Length × Number of Modules along Side

For landscape:

Side Length = Width × Number of Modules along Side

Row spacing

The distance in meters between the bottoms of two adjacent rows.

Number of rows

One row consists of one or more strings and is inclined from the horizontal at the tilt angle specified on the Array page.

For horizontal string wiring:

Number of Rows = Strings in Parallel ÷ Modules along Side

For vertical string wiring:

Number of Rows = Modules per String ÷ Modules along Side

Note. The number of rows must be an integer greater than zero. If you specify an unrealistic value for modules along side that results in a fractional number of rows, SAM discards the fractional part of the division. Similarly, if you specify a number of modules along the side that is greater than the number of rows, SAM assigns a zero to the number of rows.

Layout from Array Page

The **Modules per String** and **Strings in Parallel** values from the Array page are shown for your reference to facilitate calculating the correct shading layout values described above.

6.4.5 PV Subarrays

The Flat Plate PV Subarrays page allows you to specify the number of strings, tracking and orientation, shading and soiling, and DC derate factors for up to four subarrays of modules.

Note. Before specifying parameters on the PV Subarray page, you should specify the number of modules and inverters and AC derate factors on the Array page.

To model a typical system with a single array, enable a single subarray (Subarray 1) and disable Subarrays 2, 3, and 4.

Modeling multiple subarrays may be useful for the following applications:

- A residential or commercial rooftop system with modules installed on different roof surfaces with different orientations.

- A ground-mounted system with groups of modules installed at different orientations, with different lengths of DC wiring, or exposed to different shading scenes or soiling conditions.
- A system that combines different tracking systems.

Note. You cannot use subarrays to model a system that combines different types of modules or inverters. You can use the Multiple Subsystems analysis option to model a system as a combination of subsystems, which may consist of different types of modules and inverters.

To model a system with a single subarray of modules (typical):

1. On the Array page, either specify the desired array size, or specify the number of modules per string, number of strings in parallel, and number of inverters.
2. On the PV Subarrays page, disable Subarrays 2, 3, and 4.
3. On the PV Subarrays page, for Subarray 1, specify the array tracking and orientation parameters, DC derate factors and optional shading and soiling factors.

To model a system with a multiple subarrays of modules:

1. On the Array page, either specify the desired array size, or specify the number of modules per string, number of strings in parallel, and number of inverters.
2. On the PV Subarrays page, enable Subarrays 2, 3, and 4 as appropriate. Subarray 1 is always enabled.
3. On the PV Subarrays page, specify the array tracking and orientation parameters, DC derate factors and optional shading and soiling factors for each subarray.

String Configuration

By default, when you create a Flat Plate PV case, SAM assigns the **Number of Strings in Parallel** value from the Array page to the number of strings for Subarray 1, and enables only Subarray 1. If you are modeling a system as a single array, you do not need to enable any other subarrays.

To model a system that consists of multiple subarrays, check **Enable** for each additional Subarray 2, 3, or 4 that you want to include in the system, and type a number of strings to allocate to each subarray. SAM allocates remaining strings to Subarray 1.

For example, to configure strings for a 10 MW system consisting of SunPower SPR-305 modules, and Advanced Energy Solaron 333 inverters with two subarrays of 5 MW each:

1. On the Module and Inverter pages, choose the SunPower module and Solaron inverter.
2. On the Array page, choose **Specify numbers of modules and inverters**, and specify 8 modules per string, 440 strings in parallel, and 3 inverters.
3. On the PV Subarrays page, enable Subarray 2, and type 220 for the number of strings allocated Subarray 2.

Note. You can enable any combination of subarrays. For example, you can model a system with two subarrays by enabling Subarrays 1 and 3, and disabling Subarrays 2 and 4.

Tracking & Orientation

The four tracking options allow you specify whether and how modules in each subarray follow the movement of the sun across the sky.

Note. SAM does not adjust installation or operating costs on the System Costs page based on the tracking options you specify. Be sure to use appropriate costs for the type of tracking system you specify.

To specify subarray tracking and orientation:

1. For each enabled subarray, choose a tracking option: Fixed, 1 axis, 2 axis, or azimuth tracking.

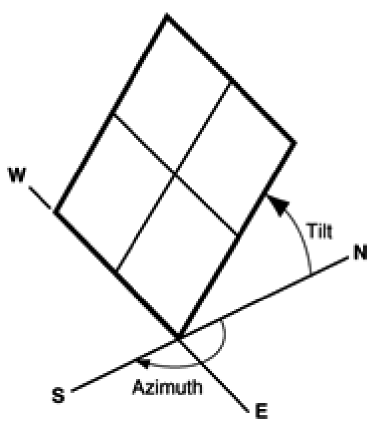
   If you use an option other than fixed, be sure that the **Balance of System** cost category on the PV System Costs page includes the cost of installing the tracking system, and that the **Operation and Maintenance** costs include the cost of maintaining the system.
2. Type a value for the subarray tilt angle in degrees from horizontal. Zero degrees is horizontal, 90 degrees is vertical.

   If you are unsure of a value, you can use the location's latitude (displayed in the navigation menu under **Location and Resource** and on the Location and Resource page), or check **Tilt = Latitude** if you want SAM to automatically assign the value of the latitude from the weather file to the array tilt angle. Note that SAM does not display the tilt angle when you choose this option, but it does use the correct value in simulations.
3. If the subarray is oriented away from due south in the northern hemisphere, change the default azimuth angle to the desired value. For southern hemisphere locations, change the azimuth value to zero degrees for an array facing due north.

   An azimuth angle of 180 degrees in the northern hemisphere, or zero in the southern hemisphere (facing the equator) usually maximizes energy production over the year.

Fixed

The subarray is fixed at the tilt and azimuth angles defined by the values of **Tilt** and **Azimuth** and does not follow the sun's movement.



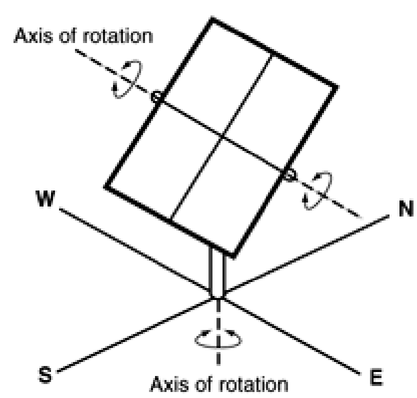
PV array facing south at fixed tilt.

1 Axis

The subarray is fixed at the angle from the horizontal defined by the value of **Tilt** and rotates about the tilted axis from east in the

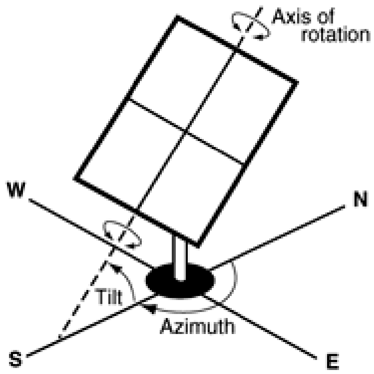
2 Axis

The subarray rotates from east in the morning to west in the evening to track the daily movement of the sun across the sky, and north-south to track the sun's seasonal movement throughout the year. For two-axis tracking, SAM ignores the values of **Tilt** and **Azimuth**.



Two-axis tracking PV array

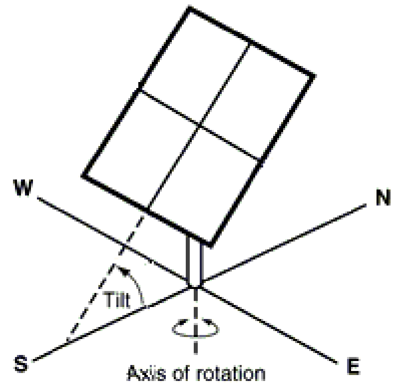
morning to west in the evening to track the daily movement of the sun across the sky. **Azimuth** determines the array's orientation with respect to a line perpendicular to the equator. For a horizontal subarray with one-axis tracking, use a **Tilt** value of zero.



One axis tracking PV array with axis oriented south.

Azimuth Axis

The subarray rotates in a horizontal plane to track the daily movement of the sun. SAM ignores the value of **Azimuth**.



Azimuth-axis tracking PV array

Note. For an example of how to use parametric analysis to optimize the tilt and azimuth angles, see Optimize Photovoltaic Array Tilt and Azimuth Angles.

Tilt = Latitude

Assigns the array tilt value with the latitude value stored in the weather file and displayed on the Location and Resource page. Note that SAM does not display the tilt value on the Array page, but does use the correct value during simulations.

Tilt, degrees

Applies only to fixed arrays and arrays with one-axis tracking. The array's tilt angle in degrees from horizontal, where zero degrees is horizontal, and 90 degrees is vertical and facing the equator (in both the southern and northern hemispheres.

As a rule of thumb, system designers sometimes use the location's latitude (shown on the Location and Resource page) as the optimal array tilt angle. The actual tilt angle will vary based on project requirements.

For a horizontal subarray, use a tilt angle of zero.

Azimuth, degrees

Applies only to fixed arrays with no tracking. The array's east-west orientation in degrees. An azimuth value of zero is facing north, 90 degrees = east, 180 degrees = south, and 270 degrees = west, regardless of whether the array is in the northern or southern hemisphere.

For systems north of the equator, a typical azimuth value would be 180 degrees. For systems south of the equator, a typical value would be 0 degrees.

> **Note.** This convention is different than that used in older versions of SAM. Please be sure to use the correct array azimuth angle convention.

Tracker Rotation Limit, degrees

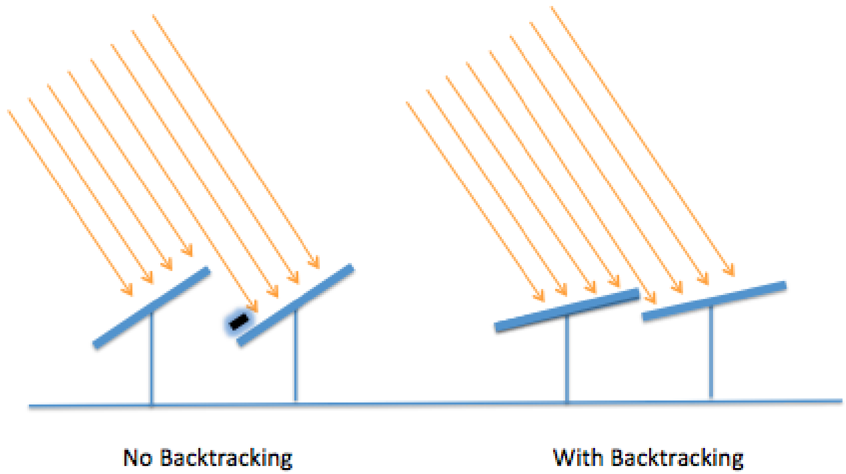
The maximum and minimum allowable rotation angle for one-axis tracking. The default value of 360 degrees allows the tracker to follow the full movement of the sun from horizon to horizon.

Shading mode for 1 axis tracking

Backtracking is a PV tracking strategy that attempts to avoid row-to-row shading of modules in an array with one-axis tracking.

Without backtracking, a tracking array typically points the modules directly at the sun. However, for an array with closely spaced rows, modules in adjacent rows may shade each other at certain sun angles, which can dramatically reduce the array's power output. With backtracking, under these conditions, the tracker will orient the modules away from the sun to avoid shading.

When you run a simulation with backtracking, SAM adjusts the tracking angle of different rows to minimize row-to-row shading. The following diagram illustrates how backtracking reduces row-to-row shading:



These options are available only when you choose **1 Axis** tracking:

- **Self-shaded** models the array with no backtracking, but does estimate losses from self-shading caused by shading of modules in one row by modules in neighboring rows based on the GCR value you specify. This is an improvement over previous versions of SAM that assumed that rows in arrays with one-axis tracking were ideally spaced to have no self shading.
- **Backtracking** adds backtracking to the self-shaded option, and adjusts the tracking angle to minimize shading.
- **None** uses the approach of the previous versions of SAM. Because this option does not account for any self-shading, it tends to overestimate the array's production. We included this option to allow for comparison between the different options to see the effect of the self-shaded and backtracking options, and for comparison between results from this version and older versions of SAM.

Ground coverage ratio (GCR)

The ratio of the photovoltaic array area to the total ground area. An array with a low ground coverage ratio (closer to zero) has rows spaced further apart than an array with a high ground coverage ratio (closer to 1).

The ground coverage ratio must be a value greater than 0.01 and less than 0.99.

To see the effect of the ground coverage ratio, you can compare the hourly simulation results **Subarray *n* Nominal POA total irradiance (kW/m2)** and **Subarray *n* POA total irradiance after shading only (kW/m2)**. You can also run a parametric analysis on the ground coverage ratio value to find its optimal value.

Note. The ground coverage ratio is completely independent from the Packing Factor variable on the Array page and has no effect on the Total Land Area value on the System Costs page. If your analysis uses costs in $/acre, you should choose a packing factor value that is consistent with the ground coverage ratio.

Shading & Soiling

The shading and soiling factors reduce the solar radiation incident on the subarray.

SAM calculates the nominal incident radiation value for each simulation time step using solar radiation values from the weather file, and sun and subarray angles. When you specify soiling or shading factors, SAM multiplies the nominal incident radiation value by each soiling and shading factor that applies to the time step.

You can see the effect of the derate factors in the hourly results (and in the monthly and annual averages) in the Tables on the Results page. In the hourly results:

Incident Beam = Nominal Incident Beam × Soiling Factor (the Soiling factor may be different for different months)

Incident Diffuse = Nominal Incident Diffuse × Soiling Factor (the Soiling factor may be different for different months)

Configure shading scene

The shading scene defines the effect of shadows from nearby objects on the subarray.

- Click **Edit shading** to specify a set of shading factors for each subarray. See Shading for details.

Monthly soiling factors

You can use the soiling factors to represent incident radiation losses due to dust, snow or other seasonal soiling of the module surface that reduce the radiation incident on the subarray.

Soiling reduces the hourly total radiation incident on the array (plane-of-array irradiance) that SAM calculates from radiation data in the weather file, and array and sun angles.

- Click **Edit values** to specify a set of monthly soiling factors.

Annual Average Soiling

The product of the twelve soiling derate factors.

Pre-inverter Derates (DC)

The pre-inverter DC derate factors account for DC electrical losses in the system that the module model does not calculate, such as electrical losses in the DC wiring that connects modules in the array.

The five DC derate factor categories (mismatch, diodes and connections, etc) are to help you keep track of factors influencing the total DC derate factor. The total DC derate factor is the product of the five factors. SAM uses the total DC derate factor in calculations.

You can see the effect of the DC derate factor in the hourly results (and in the monthly and annual averages) in the Tables on the Results page. In the hourly results:

Net DC Array Output = Gross DC Array Output × Estimated DC Power Derate 1 × Estimated DC Power Derate 2 × Estimated DC Power Derate 3 × Estimated DC Power Derate 4

Note. For a discussion of derate factors in the context of the NREL PVWatts model that includes suggested values, see the Help system for the web version of PVWatts at http://pwwatts.nrel.gov/. Note that SAM only includes derate factors for losses that the module, inverter, and shading models do not calculate.

The five DC derate categories represent the following sources of DC electrical loss:

Mismatch

Slight differences in performance of individual modules in the array.

Diodes and connections

Voltage drops across blocking diodes and electrical connections.

DC wiring loss

Resistive losses in wiring on the DC side of the system.

Tracking error

Inaccuracies in the tracking mechanisms ability to keep the array oriented toward the sun. The default value of 100% assumes a fixed array with no tracking. Applies only to systems with one- or two-axis tracking arrays.

Nameplate

Accounts for accuracy of the manufacturer's nameplate rating, often for the performance degradation modules may experience after being exposed to light.

The total DC derate factor for each subarray represents the subarray's total DC electrical loss:

Estimated DC power derate

The total pre-inverter derate factor is the product of the five DC derate factor categories.

In the hourly simulation, SAM calculates the net DC array output at the inverter's input for each hour by multiplying the gross DC array output by the total estimated DC power derate. A derate factor of 1 is equivalent to no derating. A derate factor of 0.75 would reduce the calculated array DC output by 25%.

Subarray Mismatch

The subarray mismatch option is an advanced option that calculates the effect of voltage mismatch between subarrays for systems with two or more subarrays.

Because the number of modules per string is the same for all subarrays in the system, the subarrays have the same nominal string voltage. However, during operation each subarray is exposed to different radiation levels and wind speeds, which causes the cell temperatures in each subarray to differ. Because cell voltage depends on cell temperature, each subarray will have slightly different voltages. This voltage mismatch causes electrical losses so that the inverter input voltage is less than the array's maximum power voltage.

SAM uses two methods to estimate the inverter input voltage.

Averaging Method (check box clear)

SAM calculates each subarray's output at its maximum power point voltage (Vmp), and assumes that the inverter DC input voltage is the average of the subarray Vmp values.

This method is fast and works with both the Sandia and CEC module option.

Iterative Method (check box checked)

SAM tries many string voltages to find the value that results in the maximum power from the array. For each test voltage, it finds the current from each subarray, and adds up the currents. Then the power is the summed current times the test voltage. The test voltage that yields the maximum power is used for each subarray to calculate the total output power, and this voltage is also the inverter DC input voltage.

This method takes on the order of 10-30 seconds for a system with two or more subarrays.

Notes.

The subarray mismatch option is only active with the CEC model option on the Module page.

The iterative method typically results in lower system output over the year than the averaging method. The averaging method is a reasonable approximation of mismatch losses, and is suitable for simulations where the main metric of interest is the system's total annual output for financial analysis. The difference in annual output between the two methods is often less than one percent.

6.5 High-X Concentrating PV (HCPV)

The High-X Concentrating PV (HCPV) represents a HCPV system as an array of modules with one or more inverters as specified on the Array page. SAM models the HCPV module using a cell efficiency curve and a set of loss factors that you specify on the Module page. The multi-junction cell's efficiency curve is a linear interpolation of the table of power conversion efficiencies as a function of incident beam irradiance (direct normal irradiance, or DNI) that you specify. The model uses an air mass modifier polynomial to approximate spectral effects on the performance of the module. You can also specify loss factors to account for optical lens, alignment error, tracker error, wind flutter, and other CPV-specific losses. The HCPV uses SAM's Sandia inverter model.

The HCPV input pages are:

- Location and Resource
- PV System Costs
- Array
- Module
- Inverter

The input pages for the financial model depend on the financing option. See Financing Overview for details.

6.5.1 Array

The Concentrating Array page displays inputs for the High-X Concentrating PV performance model.

SAM assumes that HCPV modules are mounted on 2-axis trackers, and calculates tracking power consumption based on the tracking power that you specify. SAM allows you to set tracker limits and to set a maximum wind speed to move modules into stow position during periods of high wind.

Array Configuration

The array configuration variables determine the number of modules and inverters in the system.

Number of trackers

The total number of trackers in the array.

Modules on each tracker

The number of modules on each tracker.

Single tracker nameplate capacity, kWdc

The capacity in DC kilowatts of a single tracker at the reference radiation value specified on the Module page.

Single Tracker Nameplate Capacity (kWdc) = Modules on Each Tracker × Module Maximum Power (Wdc) / 1000 (Wdc/kWdc)

The module maximum power is Pmp from the Module page.

System nameplate capacity, kWdc

The array's nameplate capacity in DC kilowatts at the reference radiation value specified on the Module page.

System Nameplate Capacity (kWdc) = Single Tracker Nameplate Capacity (kWdc) × Number of Trackers

Number of inverters

The number of inverters specified on the Inverter page required to match the array's capacity.

Number of Inverters = System Nameplate Capacity (kWdc) / Inverter DC Rated Power (Wdc) / 1000 (Wdc/kWdc)

The number of inverters is the nearest integer greater than the nameplate capacity divided by a single inverter's rated DC capacity.

The inverter's rated DC capacity is Power DCo from the Inverter page.

Note. The HCPV model works only in conjunction with the Sandia inverter model option on the Inverter page. The inverter single-point efficiency model is only available for the flat-plate/low-x PV model.

Inverter AC capacity, kWac

The total AC capacity of inverters in the system.

Inverter AC Capacity (kWac) = Number of Inverters × Inverter AC Rated Power (Wac) / 1000 (Wac/kWac)

The inverter's rated AC capacity is Power ACo from the Inverter page.

Tracker

The tracker options determine the type of two-axis active tracking used by the system.

General tracking error factor

Defines losses due to tracker error.

Single tracker power during operation, W

The total rated power of the tracking mechanism for a single tracker.

Tracker elevation angle limits (degrees)

Minimum and maximum values for the tracker elevation angle. SAM limits the tracker movement to values between the minimum and maximum.

Tracker azimuth angle limits (degrees)

Minimum and maximum values for the tracker azimuth angle. SAM limits the tracker movement to values between the minimum and maximum.

Soiling and derates

The soiling and derate factors account for losses in the system that the module and inverter models do not calculate, such as electrical losses in the DC wiring that connects modules in the array.

> **Note.** For a discussion of derate factors in the context of the NREL PVWatts model that includes suggested values, see the Help system for the web version of PVWatts at http://pvwatts.nrel.gov/. Note that SAM only includes derate factors for losses that the module, inverter, and shading models do not calculate.

Monthly soiling factors

Click **Edit Values** to specify the soiling derate factor that applies for each month of the year. A derate factor of 100 represents an array with no soiling, a value of 0 would be for an array that receives no sunlight. SAM assumes that Hour 1 of the 8,760 hours in a year is the hour ending at 1 am on Monday, January 1.

SAM applies the soiling derate factor to the direct radiation incident on the array.

DC wiring loss factor

A loss factor that SAM applies to the array's hourly DC output during simulations.

DC module mismatch loss factor

A loss factor that SAM applies to the array's hourly DC output during simulations.

Diodes and connections loss factor

A loss factor that SAM applies to the array's hourly DC output during simulations.

AC wiring loss factor

A loss factor that SAM applies to the system's hourly AC output during simulations.

Estimated overall system conversion efficiency, %

An estimate of the system's DC-to-AC conversion efficiency at nameplate conditions. SAM displays this value for reference only. During simulations, it calculates the system's efficiency for each hour based on the available solar resource and system properties.

Estimated Efficiency = Estimated Module Efficiency × General Tracking Error × DC Wiring Loss × Average Annual Soiling Loss × DC Module Mismatch × Diode and Connections × AC wiring × Inverter AC Capacity ÷ Inverter DC Capacity

Average Annual Soiling loss is the average of the 12 monthly soiling factors in the Edit Values window.

Stowing

Max allowed wind speed before stowing, m/s

Determines the wind speed that causes the trackers to move to stow position.

Land Area

Packing Factor

The packing factor is a multiplier that makes it possible to estimate the land area required by a project based on the total module area of the array.

Note. The packing factor only has an effect on simulation results when you specify land costs in $/acre on the PV System Costs page.

Total Land Area

The total land area is an estimate of the land area required by the PV system:

Total Land Area = Overall Module Area (m²) × Number of Trackers × Modules on Each Tracker × Packing Factor ÷ 4,047 (m²/acre)

Where Overall Module Area is from the Module page.

Shading Derate

The azimuth-by-altitude table is a two-dimensional look-up table of beam shading factors. Each column in the table contains a set of shading factors for the solar azimuth value shown in the column heading. Each row in the table contains a set of shading factors for the solar altitude value in the row heading.

Solar azimuth values in the column headings must increase monotonically from left to right. Solar altitude values must increase monotonically from bottom to top.

For each hour in the simulation, SAM calculates the position of the sun as a set of solar azimuth and altitude angles. SAM uses a linear interpolation method to estimate the value of the beam shading factor for the hour based on the nearest values in the look-up table.

Important Note: Azimuth values use the following convention: 0 = north, 90 = east, 180 = south, 270 = west.

To define the azimuth-altitude shading factor table by hand:

1. In **Rows** and **Cols**, type the number of rows and columns in the table.

   Specify a number of rows that is one greater than the number of azimuth values: For example for a table with ten rows of solar azimuth values, specify a **Rows** value of 11. Similarly, specify a **Cols** value that is one greater than the number of altitude values.
2. Type a set of column headings, solar azimuth values increasing from left to right.
3. Type a set of row headings with solar altitude values decreasing from top to bottom.

4. Type a beam shading factor value (between zero and one) in each cell of the table.

To import or export azimuth-by-altitude beam shading factors:

SAM allows you to import and export the azimuth-altitude lookup table as a comma-delimited text file that contains shading factors separated by commas. The file should have row or column headings.

- To export the shading matrix as a text file, click **Export**.
- To import a data from a comma-delimited text file, click **Import**.

6.5.2 Module

The HCPV Module page inputs are for the High-X Concentrating PV performance model.

High Concentration Photovoltaic (HCPV) Module

Single cell area, cm²

The area in square centimeters of one cell in the module.

Number of cells

The number of cells in a single module.

Concentration ratio

The ratio of lens area to cell area. SAM uses this value to calculate the Overall Module Area based on the Single Cell Area and Number of Cells that you specify.

Optical error factor

SAM applies this factor to the plane-of-array beam irradiance to adjust the value to account for losses due to lens optical error.

Alignment loss factor

SAM applies this factor to the plane-of-array beam irradiance to adjust the value to account for losses due to alignment error.

Wind flutter loss factor (per m/s)

SAM uses this factor to reduce the cell power value based on the wind speed to account for losses due to motion of the module caused by the wind. For each time step in the simulation, SAM reduces the calculated cell output power by *1 - Flutter Loss Factor × Wind Speed*.

Maximum Power (Pmp), Wdc

The module's maximum power point rating in DC Watts.

Maximum Power (Wdc) = Reference Cell Efficiency (%) ÷ 100
× Reference POA Irradiance (W/m²)
× Overall Module Area (m²)
× Optical Error Factor
× (1 - Wind Flutter Loss Factor × 4 m/s)
× Alignment Loss Factor
× Modifier at AM 1.5

Overall module area, m^2

The module's reflective area in square meters.

Overall Module Area (m^2) = Concentration Ratio × Single Cell Area (cm^2) × 0.0001 (m^2/cm^2) × Number of Cells

Estimated reference module efficiency, %

The module's nominal efficiency.

Estimated Module Efficiency (%) = Reference Cell Efficiency (%)
× Optical Error Factor
× (1 - Wind Flutter Loss Factor × 4 m/s)
× Alignment Loss Factor
× Modifier at AM 1.5

Spectral Effects

As you enter air mass modifier coefficients, SAM displays the air mass modifier values as a function of solar zenith angle in the graph that SAM will use during simulations.

Air mass modifier coefficients (a0 - a4)

Air mass coefficients.

Modifier at AM 1.5

Reference air mass coefficient at 1.5 Air Mass.

Modifier at AM 1.5 = a0 + a1 × 1.5 + a2 × 2.25 + a3 × 5.0625 + a4 × 7.59375

Reset to AM Defaults

Replaces the a0 - a4 coefficient values with default value.

Multi-Junction Cell Efficiency

The cell efficiency table defines the cell's efficiency curve. Specify the cell efficiency at each of up to five plane-of-array (POA) beam irradiance values, and specify the reference value for capacity calculations.

SAM uses the reference value to determine the module capacity used in capacity-related cost calculations and to calculate the system's capacity factor.

During simulations, SAM uses linear interpolation to estimate efficiency values between the points that you specify. For example, given POA Irradiance and cell efficiency values of 34% at 400 W/m2 and 36% 600 W/m2, for an hour when the plane-of-array incident radiation value is 432 W/m2, SAM would estimate the cell efficiency at 34.32%.

Note. Be sure that the POA irradiance values increase monotonically from top to bottom.

POA Irradiance (W/m2, Beam Normal)

The beam (direct normal) radiation in the plane of the array (POA).

Concentrated (Suns)

The POA Irradiance value expressed in Suns, given the concentration ratio you specify.

Concentrated (Suns) = Concentration Ratio × POA Irradiance (W/m^2) ÷ 1000 (W/m^2 / Sun)

MJ cell efficiency (%)

The multi-junction (MJ) cell efficiency at the given POA irradiance value.

Reference

The reference POA irradiance and cell efficiency values for nameplate capacity calculations.

6.5.3 Inverter

The Sandia Performance Model for Grid-Connected PV Inverters is an empirically-based performance model that uses parameters from a database of commercially available inverters maintained by Sandia National Laboratory. The parameters are based on manufacturer specifications and laboratory measurements for a range of inverter types.

The Sandia model consists of a set of equations that SAM uses to calculate the inverter's hourly AC output based on the DC input (equivalent to the derated output of the photovoltaic array) and a set of empirically-determined coefficients that describe the inverter's performance characteristics. The equations involve a set of coefficients that have been empirically determined based on data from manufacturer specification sheets and either field measurements from inverters installed in operating systems, or laboratory measurements using the California Energy Commission (CEC) test protocol.

Because SAM does not track voltage levels in the system, it assumes that for each hour of the simulation, the inverter operates at the photovoltaic array's maximum power point voltage, given the solar resource data in the weather file for that hour.

The inverter single-point efficiency model calculates the inverter's AC output by multiplying the DC input (equivalent to the array's derated DC output) by a fixed DC-to-AC conversion efficiency that you specify on the Inverter page. Unlike the Sandia inverter model, the single-point efficiency model assumes that the inverter's efficiency does not vary under different operating conditions.

Note. SAM's Sandia inverter library contains parameters for inverters in the List of Eligible Inverters per SB1 Guidelines at http://www.gosolarcalifornia.org/equipment/inverters.php. We try to keep the library as current as possible, but there may be periods when SAM's library is out of date. If the library appears to be out of date, you can check for updates by clicking the link on the Help menu to see if we have prepared a new module library.

If you are an inverter manufacturer and would like to add your inverter to the list, you should contact the California Energy Commission (CEC) or Sandia National Laboratories directly. For information about the Sandia Test and Evaluation program, see http://energy.sandia.gov/?page_id=279. For a list of Sandia contacts, see http://energy.sandia.gov/?page_id=2772. For CEC contacts, see http://www.gosolarcalifornia.ca.gov/equipment/add.php.

The Sandia inverter model is described in King D et al, 2007. *Performance Model for Grid-Connected Photovoltaic Inverters*. Sandia National Laboratories. SAND2007-5036. http://infoserve.sandia.gov/sand_doc/2007/075036.pdf. Also see the Sandia PV Modeling and Analysis website at http://energy.sandia.gov/?page_id=2493 for more on PV system performance modeling.

The CEC inverter test protocol is described in Bower W et al, 2004. *Performance Test Protocol for Evaluating Inverters Used in Grid-Connected Photovoltaic Systems*. http://bewengineering.com/docs/index.htm

To use the Sandia inverter model:

1. Choose an inverter from the list of available inverters. SAM displays the inverter's characteristics and model coefficients for your reference.

   If you are modeling an inverter not included in the database and want to use the Sandia model, you can try to find an inverter with similar characteristics to your inverter's specifications.

Each inverter listing shows the manufacturer name, model number and AC voltage rating, and information in brackets about the organization responsible for generating the test data and the year the data was generated. "CEC" indicates that test data was generated by the California Energy Commission.

Inverter Characteristics

When you select an inverter from the Sandia database on the Inverter page, SAM displays the inverter's parameters for your reference.

Note. SAM displays a few of the parameters from the library on the Inverter page. If you want to see the complete set of parameters in the Inverter library, you can do so in the library editor.

The following table describes the parameters in the Sandia inverter library, which are explained in more detail in the King 2004 reference cited above.

AC Voltage (Vac)

Rated output AC voltage from manufacturer specifications.

Power ACo (Wac)

Maximum output AC power at reference or nominal operating conditions. Available from manufacturer specifications.

Power DCo (Wdc)

Input DC power level at which the inverter's output is equal to the maximum AC power level. Available from manufacturer specifications.

PowerSo (Wdc)

DC power required for the inverter to start converting DC electricity to AC. Also called the inverter's self-consumption power. Sometimes available from manufacturer specifications, and not to be confused with the nighttime AC power consumption.

PowerNTare (Wac)

AC power consumed by the inverter at night to operate voltage sensing circuitry when the photovoltaic array is not generating power. Available from manufacturer specifications.

Vdcmax (Vdc)

The inverter's maximum DC input voltage.

Idcmax (Adc)

The maximum DC voltage input, typically at or near the photovoltaic array's maximum power point current.

Coefficient 0 (1/V)

Empirically-determined coefficient that defines the relationship between AC and DC power levels at the reference operating condition.

Coefficient 1 (1/V)

Empirically-determined coefficient that defines the value of the maximum DC power level.

Coefficient 2 (1/V)

Empirically-determined coefficient that defines the value of the self-consumption power level.

Coefficient 3 (1/V)

Empirically-determined coefficient that defines the value of Coefficient 0.

MPPT-low (Vdc)

Manufacturer-specified minimum DC operating voltage, as described in CEC test protocol (see reference above).

Vdco (Vdc)

The average of MPPT-low and MPPT-high, as described in the CEC test protocol (see reference above).

MPPT-hi (Vdc)

Manufacturer-specified maximum DC operating voltage, as described in CEC test protocol (see reference above). The test protocol specifies that the inverter's maximum DC voltage should not exceed 80% of the array's maximum allowable open circuit voltage.

6.6 PVWatts

The PVWatts Solar Array page displays variables for SAM's implementation of NREL's PVWatts model.

SAM includes an implementation of NREL's PVWatts model to facilitate comparing results calculated by SAM's three other photovoltaic module performance models with PVWatts results, and to generate results based on the PVWatts performance model but using SAM's cost and financial model and assumptions.

> **Note.** NREL's PVWatts model is a web-based simulation model for grid-connected photovoltaic systems. To use the model or find out more about it, visit the PVWatts website at http://pvwatts.nrel.gov/ .
>
> The model is also described in the following documents:
>
> Marion B. (2010), Overview of the PV Module Model in PVWatts, http://www.nrel.gov/docs/fy10osti/49607.pdf
> Marion B et al. (2004), Recent and Planned Enhancements for PVWatts, http://www.nrel.gov/docs/fy05osti/37016.pdf
> Marion B et al. (2001), PVWatts Version 2: Enhanced Spatial Resolution for Calculated Grid-Connected PV Performance. http://www.nrel.gov/docs/fy02osti/30941.pdf.

The input pages for the PVWatts performance model are:

- PV System Costs
- Location and Resource
- PVWatts Solar Array

The input pages for the financial model depend on the financing option. See Financing Overview for details.

6.6.1 PVWatts Solar Array

The PVWatts Solar Array page displays variables for SAM's implementation of NREL's PVWatts model. For links to references describing the PVWatts model, see PVWatts.

PVWatts System Inputs

The system inputs define the size of the system, derate factor, and the array orientation.

Nameplate Capacity (kWdc)

The array's nameplate DC power rating in kilowatts under standard test conditions (STC). The DC rating is equal to a single module's DC power rating in watts at 25°C and 1,000 W/m^2 multiplied by the number of modules in the array divided by 1,000.

DC to AC Derate Factor

A factor accounting for conversion of the array's DC nameplate capacity to the system's AC power rating at STC. The default value is 0.77.

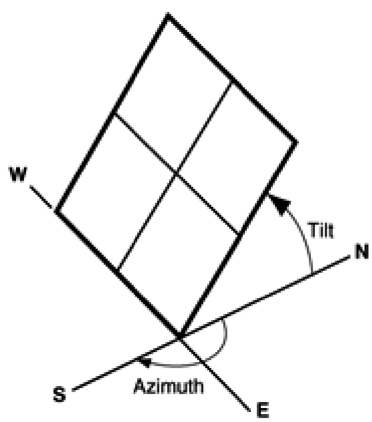
Note. SAM's implementation includes a separate shading model to estimate the effect of array shading. If you use the shading model, be sure not to include shading losses in the DC to AC Derate factor. (The default value of 0.77 does not include shading effects, assuming that the array is never shaded.)

Array Tracking Mode

The three array tracking modes are fixed, 1 axis, and 2 axis described below.

Fixed

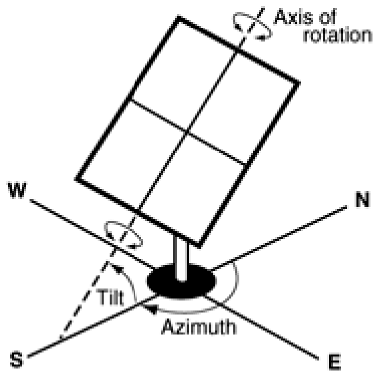
The array is fixed at the tilt and azimuth angles defined by the values of **Tilt** and **Azimuth** and does not follow the sun's movement.



PV array facing south at fixed tilt.

1 Axis

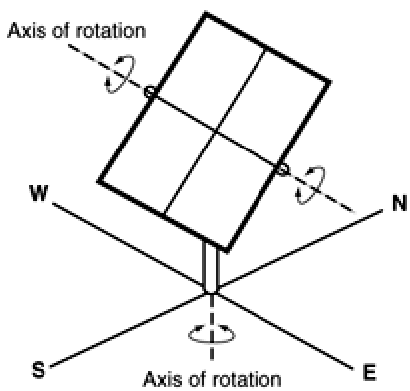
The array is fixed at the angle from the horizontal defined by the value of **Tilt** and rotates about the tilted axis from east in the morning to west in the evening to track the daily movement of the sun across the sky. **Azimuth** determines the array's orientation with respect to a line perpendicular to the equator.



One axis tracking PV array with axis oriented south.

2 Axis

The array rotates from east in the morning to west in the evening to track the daily movement of the sun across the sky, and north-south to track the sun's seasonal movement throughout the year. For two-axis tracking, SAM ignores the values of **Tilt** and **Azimuth**.



Two-axis tracking PV array

Tilt (degrees)

Applies only to fixed arrays and arrays with one-axis tracking.

The array's tilt angle in degrees from horizontal, where zero degrees is horizontal, and 90 degrees is vertical and facing the equator (in both the southern and northern hemispheres.

As a rule of thumb, system designers sometimes use the location's latitude (shown on the Location and Resource page) as the optimal array tilt angle. The actual tilt angle will vary based on project requirements.

Force Tilt = Latitude

Assigns the array tilt value with the latitude value stored in the weather file and displayed on the Location and Resource page. Note that SAM does not display the tilt value on the PVWatts Solar Array page, but does use the correct value during simulations.

Azimuth (degrees)

Applies only to fixed arrays with no tracking. The array's east-west orientation in degrees. An azimuth value of zero is facing north, 90 degrees = east, 180 degrees = south, and 270 degrees = west, regardless of whether the array is in the northern or southern hemisphere.

For systems north of the equator, a typical azimuth value would be 180 degrees. For systems south of the equator, a typical value would be 0 degrees.

Shading

The shading scene defines the effect of shadows from nearby objects on the subarray.

- Click **Edit shading** to specify a set of shading factors for each subarray. See Shading for details.

Advanced: Module thermal behavior

The module thermal behavior inputs allow you to adjust the parameters of PVWatts' temperature correction algorithm. You should not change these values unless you are familiar with the algorithm.

Installed nominal operating cell temp (INOCT)

The photovoltaic cell's nominal operating temperature.

Temperature coefficent

The cell's temperature coefficient of power.

The temperature correction algorithm is described in Fuentes, M. K. (1987). "A simplified thermal model for flat-plate photovoltaic arrays." Sandia National Laboratories. SAND85-0330. (PDF 3.6 MB).

Advanced: POA Irradiance Input

The POA Irradiance Input option allows you to model a system using your own measured hourly plane-of-array irradiance data as input. SAM calculates the system's AC electrical output using the POA irradiance data as input to the PVWatts model.

The option requires that you have an 8,760 data set of hourly POA irradiance values in Wh/m^2.

Use measured plane-of-array irradiance as model input

Check this option to use your own measured plane-of-array irradiance data instead of the solar resource data from the weather file.

SAM uses meteorological data (ambient dry-bulb temperature and wind speed) from the weather file that you specify on the Location and Resource page. If you have your own meteorological data that matches the POA irradiance data, you can use the TMY3 Creator to cut and paste your data into a TMY3 formatted weather file.

Enter hourly POA irradiance Data

1. Click **Edit Data** to open the Edit Data window.

   If your POA irradiance data is in a single column of 8,760 rows in a text file, spreadsheet file, or other file that allows you to copy it to your computer's clipboard as a single column: In your text editor, spreadsheet program, or other software, copy the column of data. In SAM's Edit Data window, click **Paste**.

If your POA irradiance data is in a text file with one row at the top containing header text followed by

8,760 rows of POA data, click **Import**,and navigate to the folder containing the text file to import it.

2. Scroll through the table to verify that all of the data was imported or pasted into the table.
3. Click **OK** to return to the PVWatts Array page.
4. On the Location and Resource page, either choose a weather file for the location where you measured the data, or use the TMY3 Creator to paste your own wind speed and ambient temperature data into a TMY3-formatted weather file.

Tip. If you are importing your POA irradiance data from a text file, before importing the data, you can export the sample data from the Edit Data window to a text file to see what the correct file format looks like.

7 Concentrating Solar Power

The Concentrating Solar Power (CSP) technologies that SAM can model are:

- Parabolic Trough (Physical)
- Parabolic Trough (Empirical)
- Power Tower Molten Salt
- Power Tower Direct Steam
- Linear Fresnel
- Dish Stirling
- Generic Solar System

For an overview of all technologies, see Technology Options.

7.1 Parabolic Trough Physical

The physical trough model calculates the electricity delivered to the grid by a parabolic trough solar field that delivers thermal energy to a power block for electricity generation, with an optional thermal energy storage system. The physical trough model characterizes many of the system components from first principles of heat transfer and thermodynamics, rather than from empirical measurements as in the empirical trough system model. While the physical trough model is more flexible than the empirical trough model, it adds more uncertainty to performance predictions than the empirical model.

For a general description of the model, see Overview.

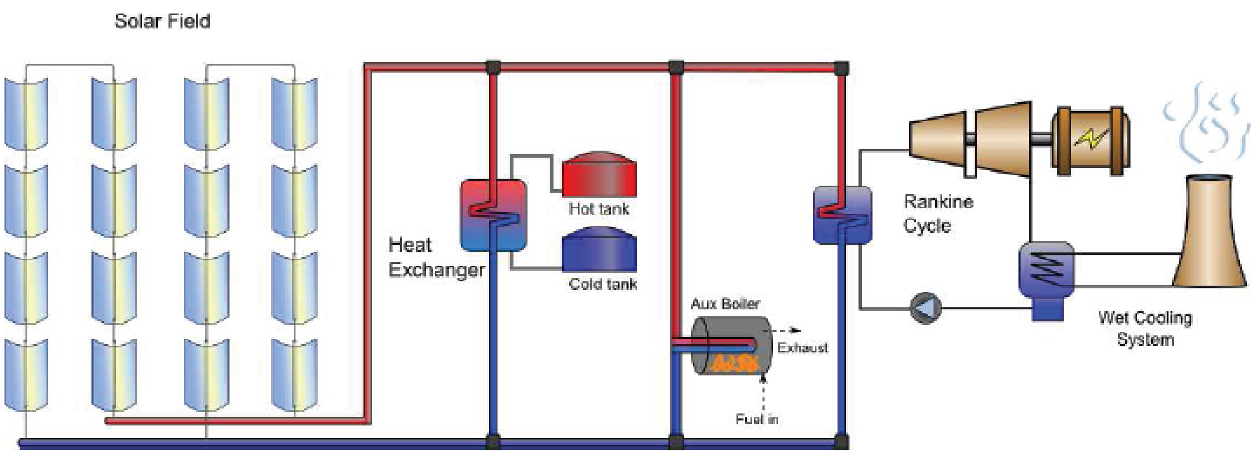
The parabolic trough input pages for this option described in this section are:

- Trough System Costs
- Solar Field
- Collectors (SCAs)

- Receivers (HCEs)
- Power Cycle
- Thermal Storage
- Parasitics

7.1.1 Trough Physical Overview

A parabolic trough system is a type of concentrating solar power (CSP) system that collects direct normal solar radiation and converts it to thermal energy that runs a power block to generate electricity. The components of a parabolic trough system are the solar field, power block, and in some cases, thermal energy storage and fossil backup systems. The solar field collects heat from the sun and consists of parabolic, trough-shaped solar collectors that focus direct normal solar radiation onto tubular receivers. Each collector assembly consists of mirrors and a structure that supports the mirrors and receivers, allows it to track the sun on one axis, and can withstand wind-induced forces. Each receiver consists of a metal tube with a solar radiation absorbing surface in a vacuum inside a coated glass tube. A heat transfer fluid (HTF) transports heat from the solar field to the power block (also called power cycle) and other components of the system. The power block is based on conventional power cycle technology, using a turbine to convert thermal energy from the solar field to electric energy. The optional fossil-fuel backup system delivers supplemental heat to the HTF during times when there is insufficient solar energy to drive the power block at its rated capacity.



The physical trough system model approaches the task of characterizing the performance of the many of the system components from first principles of heat transfer and thermodynamics, rather than from empirical measurements as in the empirical trough model. The physical model uses mathematical models that represent component geometry and energy transfer properties, which gives you the flexibility to specify characteristics of system components such as the absorber emissivity or envelope glass thickness. The empirical model, on the other hand, uses a set of curve-fit equations derived from regression analysis of data measured from real systems, so you are limited to modeling systems composed of components for which there is measured data. While the physical model is more flexible than the empirical model, it adds more uncertainty to performance predictions than the empirical model. In a physical model, uncertainty in the geometry and property assumptions for each system component results in an aggregated uncertainty at the system level that tends to be higher than the uncertainty in an empirical model. We've included both models in SAM so that you can use both in your analyses.

The following are some key features of the physical model:

- Includes transient effects related to the thermal capacity of the heat transfer fluid in the solar field piping, headers, and balance of plant.
- Allows for flexible specification of solar field components, including multiple receiver and collector types within a single loop.
- Relatively short simulation times to allow for parametric and statistical analyses that require multiple simulation runs.

As with the other SAM models for other technologies, the physical trough model makes use of existing models when possible:

- Collector model adapted from NREL's Excelergy model.
- Receiver heat loss model by Forristall (2003).
- Field piping pressure drop model by Kelley and Kearney (2006).
- Power cycle performance model by Wagner (2008) for the power tower (also known as a central receiver) CSP system model in SAM.

For publications describing the subcomponent models, see References, Parabolic Trough Technology and Modeling.

For a detailed description of SAM's physical trough model, see Wagner M, 2011. Technical Manual for the SAM Physical Trough Model. NREL/TP-550-51825. http://www.nrel.gov/docs/fy11osti/51825.pdf. You can also explore the source code written in FORTRAN for the physical trough model in the following folder of your SAM installation folder (c:\SAM\SAM 2014.1.14 by default): C:\exelib\trnsys\source. The physical trough model files are:

- Solar Field: sam_mw_trough_Type250.f90
- Collectors (SCAs): sam_mw_trough_Type250.f91
- Receivers (HCEs): sam_mw_trough_Type250.f91
- Power cycle: sam_mw_pt_TYPE224.f90
- Thermal Storage: sam_mw_trough_Type251.f90
- Parasitics: sam_mw_trough_Type251.f91 / sam_mw_pt_Type228.f90
- System control: sam_mw_trough_Type251.f90

The parabolic trough input pages for this option described in this section are:

- Trough System Costs
- Solar Field
- Collectors (SCAs)
- Receivers (HCEs)
- Power Cycle
- Thermal Storage
- Parasitics

7.1.2 Solar Field

To view the Solar Field page, click **Solar Field** on the main window's navigation menu. Note that for the physical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Physical Trough System.

The Solar Field page displays variables and options that describe the size and properties of the solar field, properties of the heat transfer fluid. It also displays reference design specifications of the solar field. See Input Variable Reference for a description of the solar field input variables.

SAM provides two options for specifying the size of the solar field: Option 1 specifies the field area as a multiple of the area required to drive the power cycle at its rated capacity under design conditions, and Option 2 specifies the field area as an explicit value in square meters. See Sizing the Solar Field for details.

You can specify the heat transfer fluid by choosing from a list of pre-defined fluids, or by creating your own fluid. See Specifying a Custom Heat Transfer Fluid for details.

SAM assumes that all collectors in the field use single-axis tracking with the collector tilt and azimuth defined by the collector orientation input variables. See the variable descriptions in Input Variable Reference for details.

The mirror washing variables determine the quantity of water required for mirror washing. See the variable descriptions in Input Variable Reference for details.

Note. For a detailed explanation of the physical trough model, see Wagner, M. J.; Gilman, P. (2011). *Technical Manual for the SAM Physical Trough Model*. 124 pp.; NREL Report No. TP-5500-51825. http://www.nrel.gov/docs/fy11osti/51825.pdf (3.7 MB)

Contents

Input Variable Reference

Solar Field Parameters

Option 1 and Option 2

For Option 1 (solar multiple mode), SAM calculates the total required aperture and number of loops based on the value you enter for the solar multiple. For option 2 (field aperture mode), SAM calculates the solar multiple based on the field aperture value you enter. Note that SAM does not use the value that appears dimmed for the inactive option. See Sizing the Solar Field for details.

Solar Multiple

The field aperture area expressed as a multiple of the aperture area required to operate the power cycle at its design capacity. See Sizing the Solar Field for details.

Field Aperture (m^2)

The total solar energy collection area of the solar field in square meters. Note that this is less than the total mirror surface area.

Note. SAM uses the **Actual Solar Multiple** and **Total Aperture Reflective Area** values shown under **Design Point** for simulations. The calculated value of the inactive option may differ from the value you see under **Solar Field Parameters**.

Row spacing (m)

The centerline-to-centerline distance in meters between rows of collectors, assuming that rows are laid out uniformly throughout the solar field. Default is 15 meters.

Stow angle (degrees)

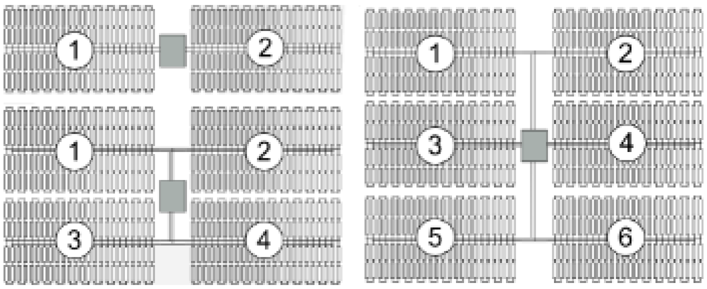
The collector angle during the hour of stow. A stow angle of zero for a northern latitude is vertical facing east, and 180 degrees is vertical facing west. Default is 170 degrees.

Deploy angle (degrees)

The collector angle during the hour of deployment. A deploy angle of zero for a northern latitude is vertical facing due east. Default is 10 degrees.

Number of field subsections

SAM assumes that the solar field is divided into between two and 12 subsections. Examples of solar field with 2, 4, and 6 subsections are shown below:



The number of field subsections determine the location and shape of header piping that delivers heat transfer fluid to the power block, which affects the heat loss calculation.

Header pipe roughness (m)

The header pipe roughness is a measure of the internal surface roughness of the header and runner piping. SAM uses this value in calculation of the shear force and piping pressure drop in the headers.

Surface roughness is important in determining the scale of the pressure drop throughout the system. As a general rule, the rougher the surface, the higher the pressure drop (and parasitic pumping power load). The surface roughness is a function of the material and manufacturing method used for the piping.

HTF pump efficiency

The electrical-to-mechanical energy conversion efficiency of the field heat transfer fluid pump. This value accounts for all mechanical, thermodynamic, and electrical efficiency losses.

Freeze protection temp (ºC)

The minimum temperature that the heat transfer fluid is allowed to reach in the field. The temperature at which freeze protection equipment is activated.

SAM assumes that electric heat trace equipment maintains the fluid at the freeze protection temperature during hours that freeze protection is operating.

Irradiation at design (W/m²)

The design point direct normal radiation value, used in solar multiple mode to calculate the aperture area required to drive the power cycle at its design capacity. Also used to calculate the design mass flow rate of the heat transfer fluid for header pipe sizing. See Sizing the Solar Field for details.

Allow partial defocusing

Partial defocusing assumes that the tracking control system can adjust the collector angle in response to the capacity of the power cycle (and thermal storage system, if applicable). See Defining Collector Defocusing for details.

Heat Transfer Fluid

Field HTF fluid

The heat transfer fluid (HTF) used in the heat collection elements and headers of the solar field. SAM includes the following options in the HTF library: Solar salt, Caloria, Hitec XL, Therminol VP-1, Hitec salt, Dowtherm Q, Dowtherm RP, Therminol 59, and Therminol 66. You can also define your own HTF using the user-defined HTF fluid option.

Note. During simulations, SAM counts the number of instances that the HTF temperature falls outside of the operating temperature limits in the table below. If the number of instances exceeds 50, it displays a simulation warning message on the Results page with the HTF temperature and time step number for the 50th instance.

Heat transfer fluids on the Field HTF Fluid list.

Name	Type	Min Optimal Operating Temp ºC	Max Optimal Operating Temp* ºC	Freeze Point ºC	Comments
Hitec Solar Salt	Nitrate Salt	238	593	238	
Hitec	Nitrate Salt	142	538	142	
Hitec XL	Nitrate Salt	120	500	120	
Caloria HT 43	Mineral Hydrocarbon	-12	315	-12 (pour point)	used in first Luz trough plant, SEGS I

Name	Type	Min Optimal Operating Temp ºC	Max Optimal Operating Temp* ºC	Freeze Point ºC	Comments
Therminol VP-1	Mixture of Biphenyl and Diphenyl Oxide	12	400	12 (crystallization point)	Standard for current generation oil HTF systems
Therminol 59	Synthetic HTF	-45	315	-68 (pour point)	
Therminol 66	?	0	345	-25 (pour point)	
Dowtherm Q	Synthetic Oil	-35	330	n/a	
Dowtherm RP	Synthetic Oil	n/a	330	n/a	

*The maximum optimal operating temperature is the value reported as "maximum bulk temperature" on the product data sheets.

Data Sources for HTF Properties

Hitec fluids: Raade J, Padowitz D, Vaughn J. Low Melting Point Molten Salt Heat Transfer Fluid with Reduced Cost. Halotechnics. Presented at SolarPaces 2011 in Granada, Spain.

Caloria HT 43: Product comparison tool on Duratherm website.

Therminol Fluids: Solutia Technical Bulletins 7239115C, 7239271A, 7239146D.

Dowtherm Fluids: Dow Data Sheet for Q, no data sheet available for RP (high temp is from website): http://www.dow.com/heattrans/products/synthetic/dowtherm.htm).

User-defined HTF fluid

To define your own HTF, choose User-defined for the Field HTF fluid and specify a table of material properties for use in the solar field. You must specify at least two data points for each property: temperature, specific heat, density, viscosity, and conductivity. See Specifying a Custom Heat Transfer Fluid for details.

Field HTF min operating temp (ºC)

The minimum HTF operating temperature recommended by the HTF manufacturer.

In some cases the minimum operating temperature may be the same as the fluid's freeze point. However, at the freeze point the fluid is typically significantly more viscous than at design operation temperatures, so it is likely that the "optimal" minimum operating temperature is higher than the freeze point.

Field HTF max operating temp (ºC)

The minimum HTF operating temperature recommended by the HTF manufacturer.

Operation at temperatures above this value may result in degradation of the HTF and be unsafe. To avoid this, you may want to include a safety margin and use a maximum operating temperature value slightly lower than the recommended value.

Design loop inlet temp (ºC)

The temperature of HTF at the loop inlet under design conditions. The actual temperature during operation may differ from this value. SAM sets the power cycle's design outlet temperature equal to this value.

Design loop outlet temp (ºC)

The temperature of the HTF at the outlet of the loop under design conditions. During operation, the actual value may differ from this set point. This value represents the target temperature for control of the HTF flow through the solar field and will be maintained when possible.

Min single loop flow rate (kg/s)

The minimum allowable flow rate through a single loop in the field.

During time steps that produce a solar field flow rate that falls below the minimum value, the HTF temperature leaving the solar field will be reduced in temperature according to the heat added and minimum mass flow rate.

Max single loop flow rate (kg/s)

The maximum allowable flow rate through a single loop in the field.

During time steps that produce a solar field flow rate that exceeds the maximum value, the solar field will be defocused according to the strategy selected by the user on the Solar Field page until the absorbed energy and corresponding mass flow rate fall below the maximum value.

Min field flow velocity (m/s)

The minimum allowable HTF flow velocity through the field.

Max field flow velocity (m/s)

The maximum allowable HTF flow velocity through the field.

The minimum and maximum solar field HTF flow velocity depend on the minimum and maximum HTF mass flow rates, HTF density at the design loop inlet temperature, and the absorber tube inner diameter specified on the Receivers page. SAM calculates the field HTF flow velocity for the receiver type with the smallest diameter.

Variable Name	Equation	Notes
Min field flow velocity	$= \frac{\dot{m}_{loop,min} * 4}{\rho_{HTF,in} * \pi * D^2_{tube,min}}$	Evaluate rho at SF inlet temp Minimum tube diameter is for tube diameters from whole loop
Max field flow velocity	$= \frac{\dot{m}_{loop,max} * 4}{\rho_{HTF,out} * \pi * D^2_{tube,min}}$	Evaluate rho at SF outlet temp

Header design min flow velocity (m/s)

The minimum allowable HTF flow velocity in the header piping under design conditions.

Header design max flow velocity (m/s)

The maximum allowable HTF flow velocity in the header piping under design conditions. The minimum/ maximum header flow velocities are used to determine the diameter of the header piping as flow is diverted to each loop in the field. After flow is distributed (or collected) to/from the loops, System Advisor calculates the flow velocity and resizes the piping to correspond to the maximum velocity if the calculated value falls outside of the user-specified range.

Design Point

The design point variables show values at the Irradiation at Design Value that SAM uses to determine the system capacity in sizing calculations, and for area-based costs on the System Costs page.

For a description of the equations for the design point variables, see See Equations for Calculated Values.

Single loop aperture (m^2)

The aperture area of a single loop of collectors, equal to the product of aperture width, reflective area, times the structure length times the number of collector assemblies per loop according to the distribution of the up to four collector types in the field. This area does not include non-reflective surface on the collector or non-reflective space between collectors.

Single Loop Aperture (m^2) = Sum of the SCA Reflective Aperture Area (m^2) values for each SCA in the loop

The SCA reflective aperture area for each SCA type is specified on the Collectors (SCAs) page. The number of each type of SCA in a single loop is specified under **Single Loop Configuration** as described in Specifying the Loop Configuration.

Loop optical efficiency

The optical efficiency when incident radiation is normal to the aperture plane, not including end losses or cosine losses. This value does not include thermal losses from piping and the receivers.

Loop Optical Efficiency = SCA Optical Efficiency at Design × HCE Optical Derate

The SCA and HCE optical efficiency values are from the Collectors (SCA) page and Receivers (HCEs) page, respectively.

Total loop conversion efficiency

The total conversion efficiency of the loop, including optical losses and estimated thermal losses. Used to calculate the required aperture area of the solar field.

Total required aperture, SM=1 (m^2)

The exact mirror aperture area required to meet the design thermal output for a solar multiple of 1.0. SAM uses the required aperture to calculate the total aperture reflective area. The total aperture reflective area may be slightly more or less than the required aperture, depending on the collector dimensions you specify on the Collectors page.

Required number of loops, SM=1

The exact number of loops required to produce the total required aperture at a solar multiple of 1.0. This number may be a non-integer value, SAM rounds this value to the nearest integer to calculate the value of the actual number of loops variable.

Actual number of loops

The actual number of loops in the field, equal to the solar multiple times the required number of loops at a solar multiple of 1.0. The required number of loops is rounded to the nearest integer to represent a realistic field layout.

Total aperture reflective area (m^2)

The actual aperture area based on the actual number of loops in the field, equal to the single loop aperture times the actual number of loops.

Actual solar multiple

For Option 1 (solar multiple mode), the calculated solar multiple based on the actual (rounded) number of loops in the field. For Option 2 (field aperture mode), the solar multiple value corresponding to the thermal output of the field based at design point: The total aperture reflective area divided by the field thermal output.

Field thermal output (MWt)

The thermal energy delivered by the solar field under design conditions at the actual solar multiple.

Equations for Calculated Values

The following table shows the equations SAM uses to calculate the values for the variables above that you cannot edit. (In Windows, the calculated values appear in blue.)

Variable Name	Equation	Notes
Single loop aperture	$= \Sigma_{i=0}^{N_{SCA}} A_{SCA,i}$	Sum of aperture area of each individual SCA in the loop
Loop optical efficiency	= Aggregate SCA Efficiency * Aggregate Receiver Optical Efficiency	Efficiencies are calculated elsewhere
Total loop conversion efficiency	= Loop Optical Efficiency * Receiver Heat Loss Efficiency	$\eta_{loop,tot}$ used in Total Required Aperture equation
Total required aperture, SM=1	$= \frac{W_{des,gross}}{\eta_{des} * DNI_{des} * \eta_{loop,tot}} * 1e6$	$A_{sf,SM1}$ used in Required Number of Loops equation
Required number of loops, SM=1	$= \frac{A_{sf,SM1}}{A_{loop}}$	
Actual number of loops	$round\left[SM * \frac{A_{sf,tot}}{A_{loop}}\right]$ $round\left[\frac{A_{sf,tot}}{A_{loop}}\right]$	Equation depends on solar field option: Option 1 uses the solar multiple value that you specify, Option 2 uses the field aperture area that you specify.
Total aperture reflective area	$= A_{loop} * N_{loop,actual}$	
Actual solar multiple	SM $\frac{A_{sf,tot}}{A_{sf,SM1}}$	Equation depends on solar field option: Option 1 is the solar multiple value that you specify, Option 2 is the ratio.
Field thermal output	$= SM * \frac{W_{des,gross}}{\eta_{pb,des}}$	pb = power block
Solar field area	$= A_{sf,tot} * \frac{L_{row\ spacing}}{\max[W_{SCA,i}]} * 0.0002471$	$W_{SCA,i}$ is the aperture width of each SCA i in the loop
Total land area	= Solar field area * Non-Solar field land area multiplier	

Collector Orientation

Collector tilt (degrees)

The angle of all collectors in the field in degrees from horizontal, where zero degrees is horizontal. A positive value tilts up the end of the array closest to the equator (the array's south end in the northern hemisphere), a negative value tilts down the southern end. SAM assumes that the collectors are fixed at the tilt angle.

Collector azimuth (degrees)

The azimuth angle of all collectors in the field, where zero degrees is pointing toward the equator, equivalent to a north-south axis. West is 90 degrees, and east is -90 degrees. SAM assumes that the collectors are oriented 90 degrees east of the azimuth angle in the morning and track the daily movement of the sun from east to west.

Mirror Washing

SAM reports the water usage of the system in the results based on the mirror washing variables. The annual water usage is the product of the water usage per wash and 365 (days per year) divided by the washing frequency.

Water usage per wash (L/m²,aper)

The volume of water in liters per square meter of solar field aperture area required for periodic mirror washing.

Washes per year

The number of washes in a single year.

Plant Heat Capacity

The plant heat capacity values determine the thermal inertia due to the mass of hot and cold headers, and of SCA piping, joints, insulation, and other components whose temperatures rise and fall with the HTF temperature. SAM uses the thermal inertia values in the solar field energy balance calculations.

You can use the hot and cold piping thermal inertia inputs as empirical adjustment factors to help match SAM results with observed plant performance.

Hot piping thermal inertia (kWht/K-MWt)

The thermal inertia of the hot header to account for any thermal inertia not accounted for in the HTF volume calculations: Thermal energy in kilowatt-hours per gross electricity capacity in megawatts needed to raise the hot side temperature one degree Celsius. The default value is 0.2 kWht/K-MWt.

Cold piping thermal inertia (kWht/K-MWt)

The thermal inertia of the cold header to account for any thermal inertia not accounted for in the HTF volume calculations: Thermal energy in kilowatt-hours per gross electricity capacity in megawatts needed to raise the hot side temperature one degree Celsius. The default value is 0.2 kWht/K-MWt.

Field loop thermal inertia (Wht/K-m)

The thermal inertia of piping, joints, insulation, and other SCA components: The amount of thermal energy per meter of SCA length required to raise the temperature of piping, joints, insulation, and other SCA components one degree K. The default value is 4.5 Wht/K-m.

Land Area

Solar Field Land Area (m²)

The actual aperture area converted from square meters to acres:

Solar Field Area (acres) = Actual Aperture (m²) × Row Spacing (m) / Maximum SCA Width (m) × 0.0002471 (acres/m²)

The maximum SCA width is the aperture width of SCA with the widest aperture in the field, as specified in the loop configuration and on the Collectors (SCA) page.

Non-Solar Field Land Area Multiplier

Land area required for the system excluding the solar field land area, expressed as a fraction of the solar field aperture area. A value of one would result in a total land area equal to the total aperture area. The default value is 1.4.

Total Land Area (acres)

Land area required for the entire system including the solar field land area

Total Land Area (acres) = Solar Field Area (acres) × (1 + Non-Solar Field Land Area Multiplier)

The land area appears on the System Costs page, where you can specify land costs in dollars per acre.

Single Loop Configuration

Number of SCA/HCE assemblies per loop

The number of individual solar collector assemblies (SCAs) in a single loop of the field. Computationally, this corresponds to the number of simulation nodes in the loop. See Specifying the Loop Configuration for details.

Edit SCAs

Click **Edit SCAs** to assign an SCA type number (1-4) to each of the collectors in the loop. Use your mouse to select collectors, and type a number on your keyboard to assign a type number to the selected collectors. SAM indicates the SCA type by coloring the rectangle representing the collector in the diagram, and displaying the type number after the word "SCA." See Specifying the Loop Configuration for details.

Edit HCEs

Click **Edit HCEs** to assign a receiver type number (1-4) to each of the collectors in the loop. Use your mouse to select collectors, and type a number on your keyboard to assign a type number. SAM indicates the HCE type by coloring the line representing the receiver, and displaying the type number after the word "HCE." See Specifying the Loop Configuration for details.

Edit Defocus Order

Click **Edit Defocus Order** to manually define the defocus order of the collectors in the field. Click an assembly to assign the defocus order. You should assign each collector a unique defocus order number. See Defining Collector Defocusing for details.

Reset Defocus

Click to reset the defocus order to the default values, starting at the hot end of the loop and proceeding sequentially toward the cold end of the loop. See Defining Collector Defocusing for details.

Sizing the Solar Field

Sizing the solar field of a parabolic trough system in SAM involves determining the optimal solar field aperture area for a system at a given location. In general, increasing the solar field area increases the system's electric output, thereby reducing the project's LCOE. However, during times there is enough solar resource, too large of a field will produce more thermal energy than the power block and other system components can handle. Also, as the solar field size increases beyond a certain point, the higher installation and operating costs outweigh the benefit of the higher output.

An optimal solar field area should:

- Maximize the amount of time in a year that the field generates sufficient thermal energy to drive the power block at its rated capacity.
- Minimize installation and operating costs.
- Use thermal energy storage and fossil backup equipment efficiently and cost effectively.

The problem of choosing an optimal solar field area involves analyzing the tradeoff between a larger solar field that maximizes the system's electrical output and electricity revenue, and a smaller field that minimizes installation and operating costs.

The levelized cost of energy (LCOE) is a useful metric for optimizing the solar field size because it includes the amount of electricity generated by the system, the project installation costs, and the cost of operating and maintaining the system over its life. Optimizing the solar field involves finding the solar field aperture area that results in the lowest LCOE. For systems with thermal energy storage systems, the optimization involves finding the combination of field area and storage capacity that results in the lowest LCOE.

For an example showing how to use parametric analysis to optmize the solar field for a trough system with storage, see the *Parabolic Trough Field and Storage Optimization* sample file: On the **File** menu, click **Open Sample File**, and choose the file from the list.

Option 1 and Option 2

SAM provides two options for specifying the solar field aperture area: Option 1 (solar multiple) allows you to specify the solar field area as a multiple of the power block's rated capacity (design gross output), and Option 2 (field aperture) allows you to specify the solar field aperture area as an explicit value in square meters.

- Option 1: You specify a solar multiple, and SAM calculates the solar field aperture area required to meet power block rated capacity.
- Option 2: You specify the aperture area independently of the power block's rated capacity.

If your analysis involves a known solar field area, you should use Option 2 to specify the solar field aperture area explicitly.

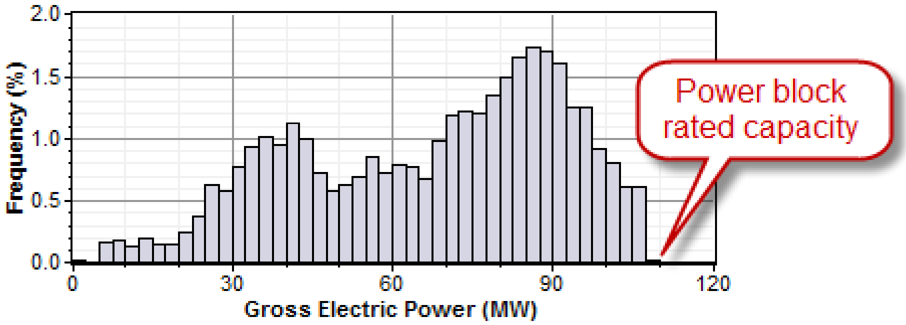
If your analysis involves optimizing the solar field area for a specific location, or choosing an optimal combination of solar field aperture area and thermal energy storage capacity, then you should choose Option 1, and follow the procedure described below to size the field.

Solar Multiple

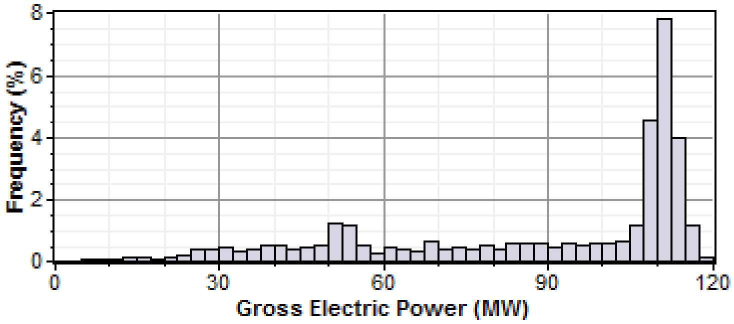
The solar multiple makes it possible to represent the solar field aperture area as a multiple of the power block rated capacity. A solar multiple of one (SM=1) represents the solar field aperture area that, when exposed to solar radiation equal to the design radiation value (irradiation at design), generates the quantity of thermal energy required to drive the power block at its rated capacity (design gross output), accounting for thermal and optical losses.

Because at any given location the number of hours in a year that the actual solar resource is equal to the design radiation value is likely to be small, a solar field with SM=1 will rarely drive the power block at its rated capacity. Increasing the solar multiple (SM>1) results in a solar field that operates at its design point for more hours of the year and generates more electricity.

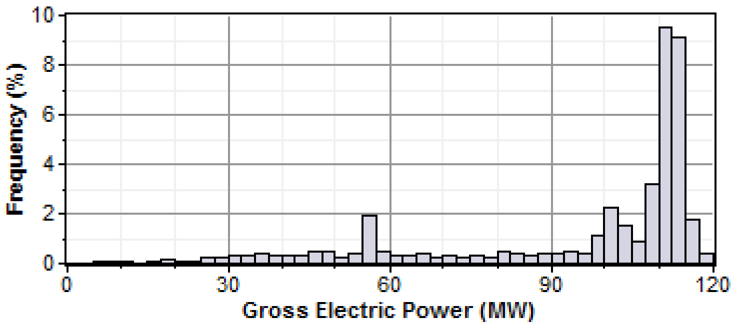
For example, consider a system with a power block design gross output rating of 111 MW and a solar multiple of one (SM=1) and no thermal storage. The following frequency distribution graph shows that the power block never generates electricity at its rated capacity, and generates less than 80% of its rated capacity for most of the time that it generates electricity:



For the same system with a solar multiple chosen to minimize LCOE (in this example SM=1.5), the power block generates electricity at or slightly above its rated capacity almost 15% of the time:



Adding thermal storage to the system changes the optimal solar multiple, and increases the amount of time that the power block operates at its rated capacity. In this example, the optimal storage capacity (full load hours of TES) is 3 hours with SM=1.75, and the power block operates at or over its rated capacity over 20% of the time:



Note. For clarity, the frequency distribution graphs above exclude nighttime hours when the gross power output is zero.

Reference Weather Conditions for Field Sizing

The design weather conditions values are reference values that represent the solar resource at a given location for solar field sizing purposes. The field sizing equations require three reference condition variables:

- Ambient temperature
- Direct normal irradiance (DNI)

- Wind velocity

The values are necessary to establish the relationship between the field aperture area and power block rated capacity for solar multiple (SM) calculations.

Note. The design values are different from the data in the weather file. SAM uses the design values to size the solar field before running simulations. During simulations, SAM uses data from the weather file you choose on the Location and Resource page.

The reference ambient temperature and reference wind velocity variables are used to calculate the design heat losses, and do not have a significant effect on the solar field sizing calculations. Reasonable values for those two variables are the average annual measured ambient temperature and wind velocity at the project location. For the physical trough model, the reference temperature and wind speed values are hard-coded and cannot be changed. The linear Fresnel and generic solar system models allow you to specify the reference ambient temperature value, but not the wind speed. The empirical trough model allows you to specify both the reference ambient temperature and wind speed values.

The reference direct normal irradiance (DNI) value, on the other hand, does have a significant impact on the solar field size calculations. For example, a system with reference conditions of 25°C, 950 W/m^2, and 5 m/s (ambient temperature, DNI, and wind speed, respectively), a solar multiple of 2, and a 100 MWe power block, requires a solar field area of 871,940 m^2. The same system with reference DNI of 800 W/m^2 requires a solar field area of 1,055,350 m^2.

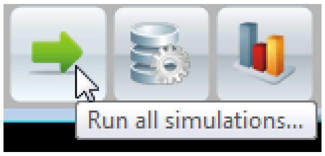
In general, the reference DNI value should be close to the maximum actual DNI on the field expected for the location. For systems with horizontal collectors and a field azimuth angle of zero in the Mohave Desert of the United States, we suggest a design irradiance value of 950 W/m2. For southern Spain, a value of 800 W/m2 is reasonable for similar systems. However, for best results, you should choose a value for your specific location using one of the methods described below.

Linear collectors (parabolic trough and linear Fresnel) typically track the sun by rotating on a single axis, which means that the direct solar radiation rarely (if ever) strikes the collector aperture at a normal angle. Consequently, the DNI incident on the solar field in any given hour will always be less than the DNI value in the resource data for that hour. The cosine-adjusted DNI value that SAM reports in simulation results is a measure of the incident DNI.

Using too low of a reference DNI value results in excessive "dumped" energy: Over the period of one year, the actual DNI from the weather data is frequently greater than the reference value. Therefore, the solar field sized for the low reference DNI value often produces more energy than required by the power block, and excess thermal energy is either dumped or put into storage. On the other hand, using too high of a reference DNI value results in an undersized solar field that produces sufficient thermal energy to drive the power block at its design point only during the few hours when the actual DNI is at or greater than the reference value.

To choose a reference DNI value:

1. Choose a weather file on the Location and Resource page.
2. Enter values for collector tilt and azimuth.
3. For systems with storage, specify the storage capacity and maximum storage charge rate defined on the Thermal Storage page.
4. Click run all simulations, or press Ctrl-G.



5. On the Results page, click Time Series.
6. On the Time Series tab, click Zoom to Fit (at the bottom of the input page).

Method 1: Maximum Cosine-adjusted DNI

7. Clear all of the check boxes and check DNI-cosine effect product (W/m2) variable.
8. Read the maximum annual value from the graph, and use this value for the reference DNI.

Method 2: Minimize "Dumped" Energy

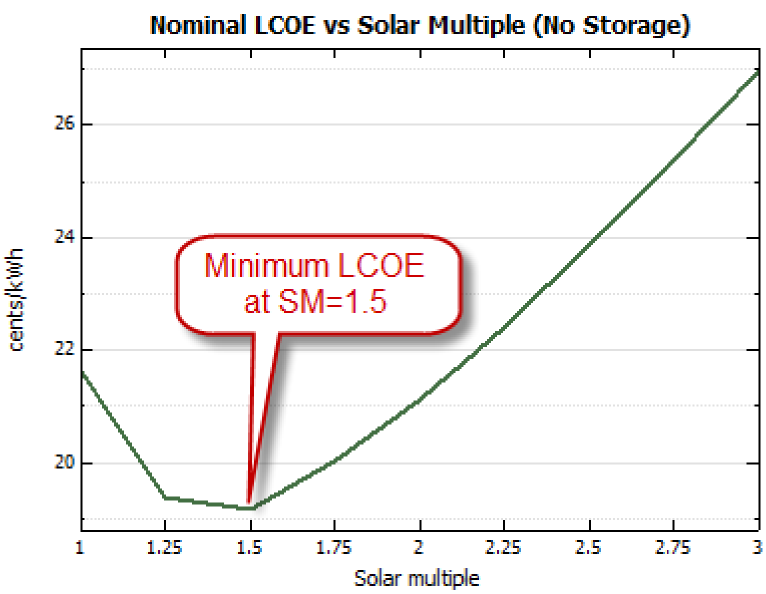
7. Clear all of the check boxes and check the dumped thermal energy variable(s).
8. If the amount of dumped thermal energy is excessive, try a lower value for the reference DNI value and run simulations again until the quantity of dumped energy is acceptable.

Optimizing the Solar Multiple

Representing the solar field aperture area as a solar multiple (Option 1) makes it possible to run parametric simulations in SAM and create graphs of LCOE versus solar multiple like the ones shown below. You can use this type of graph to find the optimal solar multiple.

For a parabolic trough system with no storage, the optimal solar multiple is typically between 1.4 and 1.5.

The graph shown below is for a system with no storage in Blythe, California, the optimal solar multiple is 2, meaning that the solar field aperture area should be chosen to be twice the area required to drive the power cycle at its rated capacity:

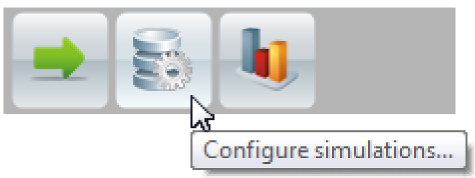


Because the optimal solar multiple depends on the LCOE, for accurate results, you should specify all of the project costs, financing, and incentive inputs in addition to the inputs specifying the physical characteristics of the solar field, power cycle and storage system before the optimization. However, for preliminary results, you can use default values for any variables for which you do not have values.

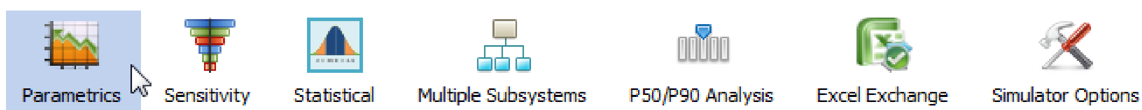
The following instructions describe the steps for optimizing the solar multiple for a preliminary system design that mostly uses default values except for a few key variables. This example is for a 50 MW system, but you can use the same procedure for a system of any size.

To optimize the solar field with no storage:

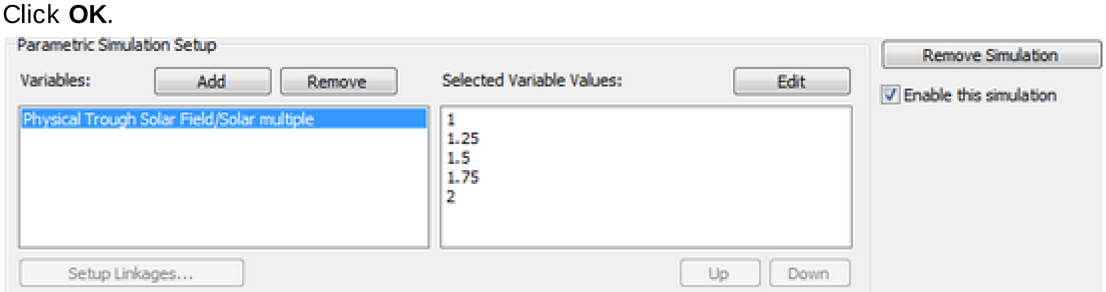
1. Create a new physical trough project with Utility IPP financing.
2. On the Location and Resource page, choose a location.
3. Follow the instructions above to find an appropriate irradiation at design value for your weather data. Use zero for both the collector tilt and azimuth variables.
4. On the Power Cycle page, for Design gross output, type 55 to specify a power block with a rated net electric output capacity of 50 MW (based on the default net conversion factor of 0.9).
5. On the Thermal Storage page, for **Full load hours of TES**, type 0 to specify a system with no storage.
6. On the Solar Field page, under **Solar Field Parameters**, choose **Option 1** (solar multiple) if it is not already active.
7. Click Configure simulations.



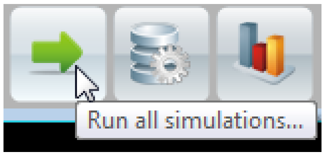
8. Click **Parametrics**.



9. Click **Add Parametric Simulation**.
10. Click **Add** to open the Choose Parametrics window.
11. In the Search box, type "solar multiple."
12. Check **Solar Multiple**.
13. Click **Edit** to open the Edit Parametric Values window.
14. Type the following values: Start Value = 1, End Value = 2, Increment = 0.25.
15. Click **Update**. The parametric simulation setup options should look like this:
16. Click **OK**.



17. Click Run all simulations. SAM will run a simulation for each of the 5 solar multiple values you specified. The simulations may take a few minutes to run.

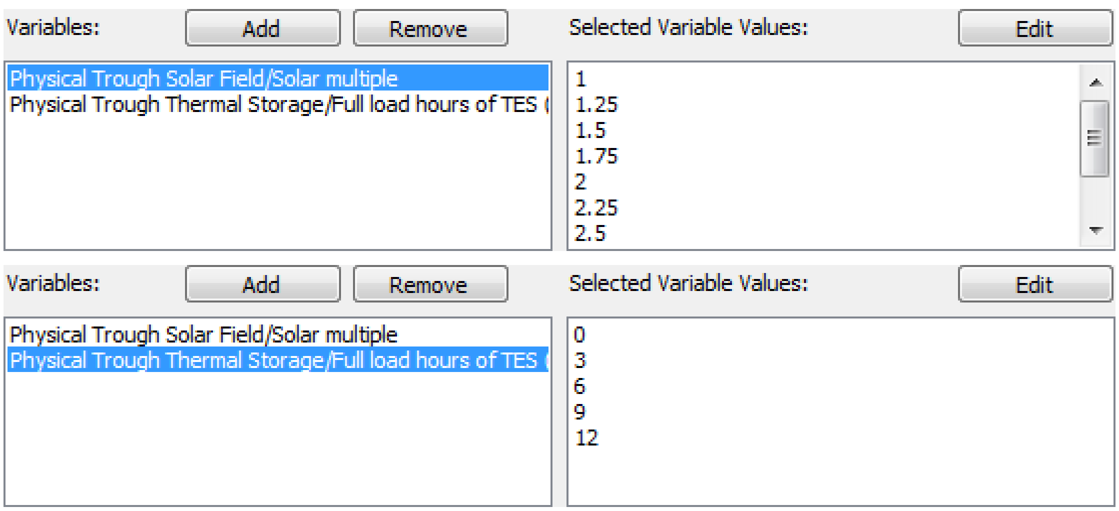


18. On the Results page, click **Add a new graph**.
19. Choose the following options: **Choose Simulation** = Parametric Set 1, **X Value** = {Solar Multiple}, **Y1 Values** = LCOE Nominal, **Graph Type** = Line Plot
20. Click **Accept**. SAM should display a graph that looks similar to the "Nominal LCOE vs Solar Multiple (No Storage)" graph above.
21. On the graph, find the solar multiple value that results in the lowest LCOE. If the minimum LCOE occurs at either end of the graph, you may need to add more values to the solar multiple parametric variable to find the optimal value.

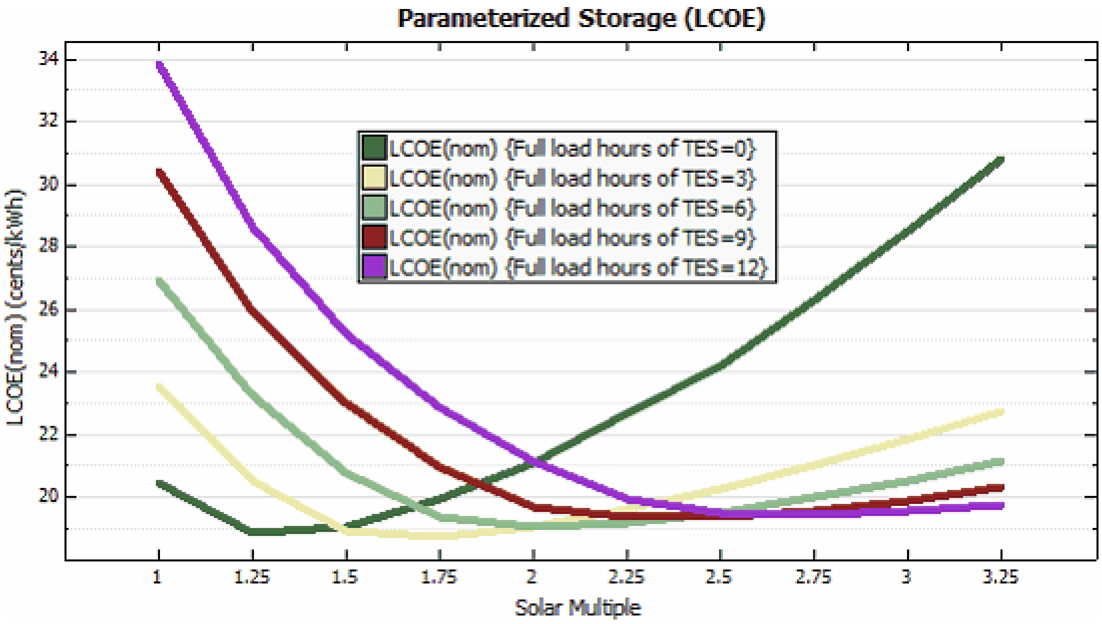
Optimal Solar Multiple for a System with Storage

Adding storage to the system introduces another level of complexity: Systems with storage can increase system output (and decrease the LCOE) by storing energy from an larger solar field for use during times when the solar field output is below the design point. However, the thermal energy storage system's cost and thermal losses also increase the LCOE.

To find the optimal combination of solar multiple and storage capacity for systems with thermal storage, run a parametric analysis as described above, but with two parametric variables instead of one: Solar multiple and Full load hours of TES (storage capacity). The parametric setup options should look similar to this:



After running simulations, you will be able to create a graph like the one below that allows you to choose the combination of solar multiple and storage capacity that minimizes the LCOE. For example, the following graph shows that for a system in Blythe, California, the optimal combination of solar multiple and thermal storage capacity is SM = 1.75 and Hours of TES = 3.



Each line in the graph represents a number of hours of thermal energy storage from the list we saw in the list of parametric values for the Equivalent Full Load Hours of TES variable: 0, 3, 6, 9, and 12 hours of storage.

For the no storage case (the dark green line, zero hours of storage), the lowest levelized cost of energy occurs at a solar multiple of 1.25. For a given storage capacity, as the solar multiple increases, both the area-dependent installation costs electricity output increase. The interaction of these factors causes the levelized cost of energy to decrease as the solar multiple increases from 1, but at some point the cost increase overwhelms the benefit of the increased electric energy output, and the levelized cost of energy begins to increase with the solar multiple.

Simplified Steps for Optimizing the Solar Field

If you are performing a preliminary analysis or learning to use SAM, you can use the following simplified steps, using default values for most of the inputs:

1. Choose a location on the Location and Resource page.
2. Specify the power cycle capacity on the Power Cycle page.
3. Choose an irradiation at design value on the Solar Field page.
4. Optimize the solar field aperture area using Option 1.

Overall Steps for Optimizing the Solar Field

1. Choose a location on the Location and Resource page.
2. Specify the power cycle capacity and other characteristics on the Power Cycle page.
3. Specify characteristics of the solar field components on the Receivers (HCEs) and Collectors (SCAs) pages.
4. If the system includes thermal energy storage, specify its characteristics on the Thermal Storage page. (Note. For systems with storage, use the optimization process in Step 8 below to find the optimal storage capacity.)

5. Define the project costs on the Trough System Costs page.
6. Configure a single loop and specify solar field heat transfer fluid (HTF) properties on the Solar Field page.
7. Specify the collector orientation on the Solar Field page.
8. Choose an irradiation at design value on the Solar Field page.
9. Either optimize the solar field aperture area using Option 1, or specify the solar field area explicitly using Option 2 on the Solar Field page.
10. Refine your analysis by adjusting other model parameters.

Specifying a Custom Heat Transfer Fluid

If the heat transfer fluid you want to use in the solar field is not included in the Field HTF Fluid list, you can define a custom heat transfer fluid using the User-defined option in the list. To define a custom fluid, you need to know the following properties for at least two temperatures:

- Temperature, ºC
- Specific heat, kJ/kg-K
- Density, kg/m³
- Viscosity, Pa-s
- Kinematic viscosity, m²-s
- Conductivity, W/m-K
- Enthalpy, J/kg

To define a custom heat transfer fluid:

1. In the Field HTF fluid list, click **User-defined**.
2. In the Edit Material Properties table, change **Number of data points** to 2 or higher. The number should equal the number of temperature values for which you have data.
3. Type values for each property in the table.

   You can also import data from a text file of comma-separated values. Each row in the file should contain properties separated by commas, in the same the order that they appear in the Edit Material Properties window. Do not include a header row in the file.

Notes

Each row in the materials property fluid table must be for a set of properties at a specific temperature. No two rows should have the same temperature value.

SAM calculates property values from the table using linear interpolation.

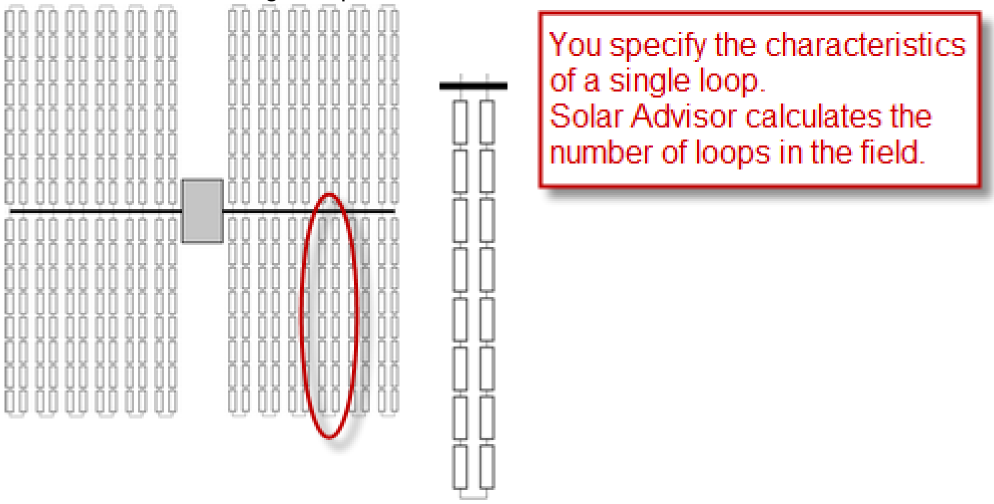
The rows in the table must sorted by the temperature value, in either ascending or descending order.

The physical trough model uses the temperature, specific heat, density, viscosity, and conductivity values. It ignores the enthalpy and kinematic viscosity values (the empirical trough model does use those values).

For the physical trough model, if you specify user-defined HTF fluids with the same properties for the solar field and thermal storage system, on the Thermal Storage page, you should set both the **Hot side HX approach temp** and **Cold side HX approach temp** to zero to represent a system with no heat exchanger. (When the hot and cold side approach temperatures are zero, **Heat exchanger derate** is one.)

Specifying the Loop Configuration

The solar field consists of loops of collector-receiver assemblies. On the Solar Field page, you specify the characteristics of a single loop in the field.



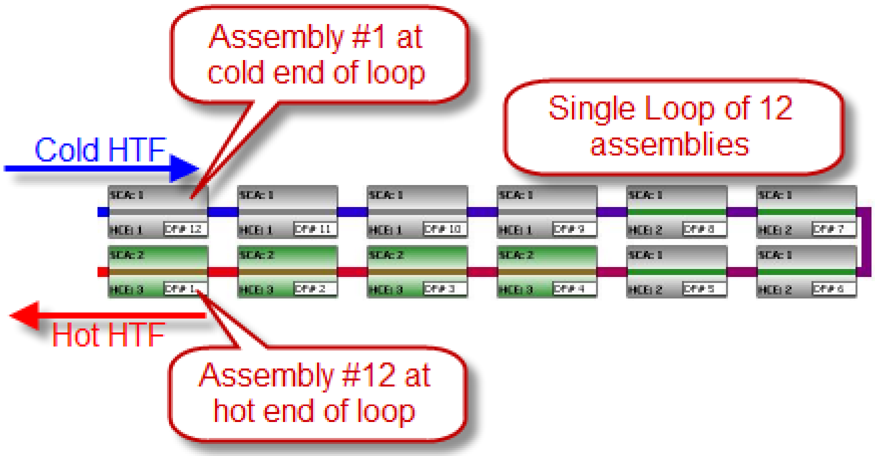
When you configure a loop, you specify the following characteristics using the single loop configuration diagram:

- Number of assemblies in a single loop.
- Collector (SCA) type of each assembly in the loop.
- Receiver (HCE) type of each assembly in the loop.
- Collector defocusing order, if applicable.

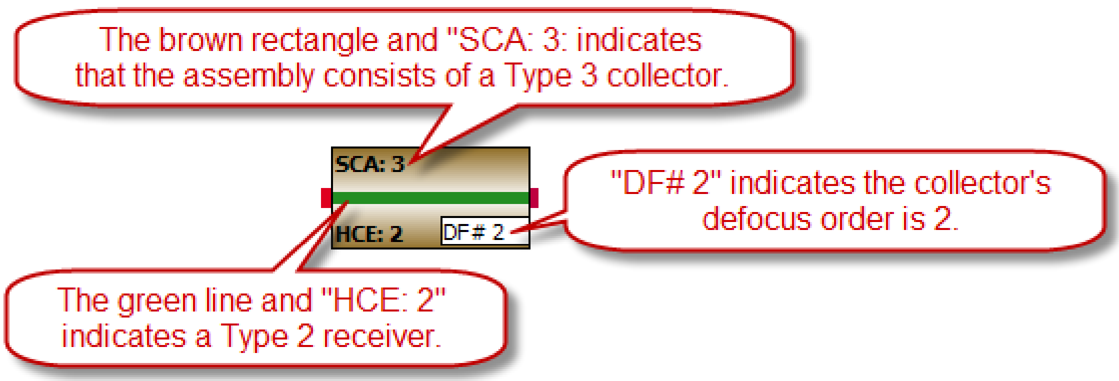
Each rectangle in the diagram represents a collector-receiver assembly. SAM allows you to specify a single loop of up to 35 collector-receiver assemblies, and up to four different receiver and collector types.

> **Note.** In the current version of SAM, it is not possible to specify more than one loop. If your field consists of different types of collectors and receivers, you must represent the proportion of different types in a single loop.

Assembly #1, at the cold end of the loop, appears at the top left corner of the diagram. Depending on the collector defocusing option you use, you may need to know each assembly's number to assign a collector defocusing order. See Defining Collector Defocusing for details.



The color of the rectangle and SCA number indicates the collector type of each assembly. Similarly, the color of the line representing the receiver and the HCE number indicates the receiver type. The "DF" number indicates the collector defocusing order:



The characteristics of each collector type are defined on the Collectors page, and of each receiver type on the Receivers page.

To specify the loop configuration:

1. In Number of SCA/HCE assemblies per loop, type a number between 1 and 32. SAM displays a rectangle for each assembly in the loop.
2. If the loop has more than one type of collector, define each of up to four collector types on the Collectors page. At this stage in your analysis, you can simply make note of the type number for each collector type you plan to include in the loop and define its characteristics on the Collectors page later.
3. Click **Edit SCAs**.

4. Use your mouse to select all of the collectors to which you want to assign a type number. You can use the Ctrl key to select individual collectors.
5. Use your keyboard to type the number corresponding to the collector's type number as defined on the Collectors page. SAM displays the collector (SCA) type number and color in the rectangle representing the collector type.
6. Repeat Steps 4-5 for each collector type in the loop.
7. If the loop includes more than one receiver type, click **Edit HCEs**, and follow Steps 4-6 for each receiver (HCE) type. You can define up to four receiver types on the Receivers page.

Defining Collector Defocusing

During hours when the solar field delivers more thermal energy than the power cycle (and thermal storage system, if available) can accept, or when the mass flow rate is higher than the maximum single loop flow rate defined on the Solar Field page, SAM defocuses collectors in the solar field to reduce the solar field thermal output. Mathematically, the model multiplies the radiation incident on the collector by a defocusing factor. In a physical system, the collector tracker would adjust the collector angle to reduce the amount of absorbed energy.

SAM provides three defocusing options:

- Option 1. No partial defocusing allowed: Collectors are either oriented toward the sun or in stow position. Collectors defocus in the order you specify. You should define a defocusing order as described below for this option.
- Option 2. Partial defocusing allowed with sequenced defocusing: Collectors can partially defocus by making slight adjustments in the tracking angle. Collectors defocus in the order you specify. You should define a defocusing order as described below for this option.
- Option 3. Partial defocusing allowed with simultaneous defocusing: Collectors can partially defocus by making slight adjustments in the tracking angle. All of the collectors in the field defocus by the same amount at the same time. You do not need to define a defocusing order for this option.

To define collector defocusing option:

- In the Solar Field Parameters options, choose a defocusing option (see descriptions above):

  Option 1: Clear **Allow partial defocusing**.

  Option 2: Check **Allow partial defocusing**, and choose **Sequenced**.

  Option 3: Check **Allow partial defocusing**, and choose **Simultaneous**.

If you choose Option 1 or Option 2, you should define the defocus order as described in the next procedure. If you choose Option 3, SAM ignores the defocusing order displayed in the single loop diagram.

To define the defocus order:

1. If you choose Option 1 or 2 for the defocusing option, under Single Loop Configuration, click Edit Defocus Order.
2. Click each collector-receiver assembly in the loop, and type a number in the Defocus Order window. Assemblies are numbered starting at the top right corner of the diagram, at the cold end of the loop. Be sure to assign a unique defocus order number to each assembly.

   Click **Reset Defocus** if you want the defocus order to start at the hot end of the loop and proceed sequentially to the cold end of the loop.

7.1.3 Collectors (SCAs)

To view the Collectors page, click **Collectors (SCAs)** on the main window's navigation menu. Note that for the physical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Physical Trough System.

A collector (SCA, solar collector assembly) is an individually tracking component of the solar field that includes mirrors, a supporting structure, and receivers.

Note. See the Troughnet website at http://www.nrel.gov/csp/troughnet/solar_field.html for more information about collectors.

On the Collectors page, you can define the characteristics of up to four collector types. On the Solar Field page, you specify how the different collector types are distributed in each loop of the field, assuming that the field consists of identical loops. SAM only uses data for collector types that you have included in the single loop specification on the Solar Field page

Note. For a detailed explanation of the physical trough model, see Wagner, M. J.; Gilman, P. (2011). *Technical Manual for the SAM Physical Trough Model*. 124 pp.; NREL Report No. TP-5500-51825. http://www.nrel.gov/docs/fy11osti/51825.pdf (3.7 MB)

Collector Type and Configuration Name

Collector Type

Choose the active SCA type (1-4). SAM displays the properties of the active SCA type on the Collectors page. You can assign different properties to each of the up to four collector types. See Specifying the Loop Configuration for details on including different SCA types in the solar field.

Configuration Name

The name of library entry for the receiver type.

Collector Geometry

Reflective aperture area (m^2)

The total reflective area of a single collector, used to calculate the loop aperture area of a loop, and number of loops required for a solar field with the aperture area defined on the Solar Field page.

Aperture width, total structure (m)

The structural width of the collector, including reflective and non-reflective area. SAM uses this value to calculate row-to-row shadowing and blocking effects.

Length of collector assembly (m)

The length of a single collector assembly.

Number of modules per assembly

The number of individual collector-receiver sections in a single collector.

Average surface-to-focus path length (m)

The average distance between the collector surface and the focus of the parabola. This value is not equal to the focal length of the collector. To calculate the value when you know the focal length and aperture width, use the following equation, where F_{avg} is the average surface-to-focus path length:

$$F_{\text{avg}} = w \cdot \sqrt{\frac{\left(4 \cdot a^2 + \left(\frac{w}{2}\right)^2\right)^2}{a^2}} \cdot \frac{12 \cdot a^2 + \left(\frac{w}{2}\right)^2}{12 \cdot w \cdot \left(4 \cdot a^2 + \left(\frac{w}{2}\right)^2\right)}$$

Where a is the focal length at the vertex, and w is the aperture width

Piping distance between assemblies (m)

Length of pipes and hoses connecting collectors in a single row, not including the length of crossover pipes.

Length of single module (m)

The length of a single collector-receiver module, equal to the collector assembly length divided by the number of modules per assembly.

Optical Parameters

Incidence angle modifier coef F0, F1, F2

Coefficients for a polynomial equation defining the incidence angle modifier equation. The equation captures the degradation of collector performance as the incidence angle (theta) of the solar radiation increases.

Tracking error

Accounts for reduction in absorbed radiation error in collectors tracking caused by poor alignment of sun sensor, tracking algorithm error, errors caused by the tracker drive update rate, and twisting of the collector end at the sun sensor mounting location relative to the tracking unit end.

Geometry effects

Accounts for errors in structure geometry caused by misaligned mirrors, mirror contour distortion caused by the support structure, mirror shape errors compared to an ideal parabola, and misaligned or distorted receiver.

Mirror reflectance

The mirror reflectance input is the solar weighted specular reflectance. The solar-weighted specular reflectance is the fraction of incident solar radiation reflected into a given solid angle about the specular reflection direction. The appropriate choice for the solid angle is that subtended by the receiver as viewed from the point on the mirror surface from which the ray is being reflected. For parabolic troughs, typical values for solar mirrors are 0.923 (4-mm glass), 0.945 (1-mm or laminated glass), 0.906 (silvered polymer), 0.836 (enhanced anodized aluminum), and 0.957 (silvered front surface).

Dirt on mirror

Accounts for reduction in absorbed radiation caused by soiling of the mirror surface. This value is not linked to the mirror washing variables on the Solar Field page.

General optical error

Accounts for reduction in absorbed radiation caused by general optical errors or other unaccounted error sources.

Optical Calculations

The optical calculations are values that SAM calculates using the equations described below. You cannot directly edit these values.

Variable Name	Equation	Note
Length of single module	= *Length of Collector Assembly ÷ Number of Modules per Assembly*	L_{col} used in End Loss at Design described below.
Incidence angle modifier at summer solstice	$= IAM_0 + \frac{\theta}{\cos\theta} * IAM_1 + \frac{\theta^2}{\cos\theta} * IAM_2$	Not used in actual efficiency calculation. Provided as reference only. Theta is in radians.
End loss at summer solstice	$= 1 - L_{f,ave} * \tan(\theta) - \left(\frac{N_{SCA}}{2} - 1\right) * \frac{2 * EG}{N_{SCA} * L_{col}}$ where: $EG = L_{f,ave} * \tan(\theta) - L_{row\ spacing}$	Optical end loss at noon on the summer solstice due to reflected radiation spilling off of the end of the collector assembly. This value is provided as a reference and is not used in determining the design of the solar field.
Optical efficiency at design	= *Tracking Error* × *Geometry Effects* × *Mirror Reflectance* × *Dirt on Mirror* × *General Optical Error*	The collector's optical efficiency under design conditions.

7.1.4 Receivers (HCEs)

To view the Receivers page, click **Receivers (HCEs)** on the main window's navigation menu. Note that for the physical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Physical Trough System.

A receiver (HCE, heat collection element) is a metal pipe contained in a vacuum within glass tube that runs through the focal line of the trough-shaped parabolic collector. Seals and bellows ensure that a vacuum is maintained in each tube. Anti-reflective coatings on the glass tube maximize the amount of solar radiation that enters the tube. Solar-selective radiation absorbing coatings on the metal tube maximize the transfer of energy from the solar radiation to the pipe.

> **Note.** See the Troughnet website at http://www.nrel.gov/csp/troughnet/solar_field.html for more information about receivers.

On the Receivers page, you define the characteristics of up to four receiver types. On the Solar Field page, you specify how the different receiver types are distributed in each loop of the field, assuming that the field consists of identical loops. SAM only uses data for receiver types that you have included in the single loop specification on the Solar Field page.

For each receiver type, you also specify up to four variations. You can use the variations to describe different conditions of the receiver type. For example, you may use one variation to describe the receiver type in good condition, and another to describe the receiver type with a damaged glass envelope.

Note. For a detailed explanation of the physical trough model, see Wagner, M. J.; Gilman, P. (2011). *Technical Manual for the SAM Physical Trough Model*. 124 pp.; NREL Report No. TP-5500-51825. http://www.nrel.gov/docs/fy11osti/51825.pdf (3.7 MB)

Contents

Input Variable Reference

Receiver Type and Configuration Name

Receiver Type

Choose the active receiver type (1-4). SAM displays the properties of the active receiver.

Configuration Name

The name of library entry for the receiver type.

Choose receiver from library

Allows you to choose a receiver from the library of available receivers.

Receiver Geometry

Absorber tube inner diameter (m)

Inner diameter of the receiver absorber tube, this surface in direct contact with the heat transfer fluid.

Absorber tube outer diameter (m)

Outer diameter of the receiver absorber tube, the surface exposed to the annular vacuum.

Glass envelope inner diameter (m)

Inner diameter of the receiver glass envelope tube, the surface exposed to the annular vacuum.

Glass envelope outer diameter (m)

Outer diameter of the receiver glass envelope tube, the surface exposed to ambient air.

Absorber flow plug diameter (m)

A non-zero value represents the diameter of an optional plug running axially and concentrically within the receiver absorber tube. A zero value represents a receiver with no plug. The plug allows for an increase in the receiver absorber diameter while maintaining the optimal heat transfer within the tube heat transfer fluid. For a non-zero value, be sure to use annular flow for the absorber flow pattern option.

Internal surface roughness

The surface roughness of the inner receiver pipe surface exposed to the heat transfer fluid, used to determine flow shear force and the corresponding pressure drop across the receiver.

Surface roughness is important in determining the scale of the pressure drop throughout the system. As a general rule, the rougher the surface, the higher the pressure drop (and parasitic pumping power load). The surface roughness is a function of the material and manufacturing method used for the piping. A conservative roughness value for extruded steel pipe (the type often used for the absorber pipe) is about 3e-6 meters. The default value of 4.5e-5 m is based on this value and the absorber tube inner diameter value of 0.066 m: 3e-6 m / 6.6e-2 m = 4.5e-5.

Absorber flow pattern (m)

Use standard tube flow when the absorber flow plug diameter is zero. Use annual flow with a non-zero absorber flow plug diameter.

Absorber material type

The material used for the absorber tube. Choose from stainless steel or copper.

Parameters and Variations

Variant weighting fraction

The fraction of the solar field that consists of the active receiver variation. For each receiver type, the sum of the four variations should equal one. See Specifying Receiver Type Variations for details.

Absorber absorptance

The ratio of radiation absorbed by the absorber to the radiation incident on the absorber.

Absorber emittance

The energy radiated by the absorber surface as a function of the absorber's temperature. You can either specify a table of emittance and temperature values, or specify a single value that applies at all temperatures.

Envelope absorptance

The ratio of radiation absorbed by the envelope to the radiation incident on the envelope, or radiation that is neither transmitted through nor reflected from the envelope. Used to calculate the glass temperature. (Does not affect the amount of radiation that reaches the absorber tube.)

Envelope emittance

The energy radiated by the envelope surface.

Envelope transmittance

The ratio of the radiation transmitted through the glass envelope to the radiation incident on the envelope, or radiation that is neither reflected nor refracted away from the absorber tube.

Broken glass

Option to specify that the envelope glass has been broken or removed, indicating that the absorber tube is directly exposed to the ambient air.

Annulus gas type

Gas type present in the annulus vacuum. Choose from Hydrogen, air, or Argon.

Annulus pressure (torr)

Absolute pressure of the gas in the annulus vacuum, in torr, where 1 torr = 133.32 Pa

Estimated avg heat loss (W/m)

An estimated value representing the total heat loss from the receiver under design conditions. SAM uses the value to calculate the total loop conversion efficiency and required solar field aperture area for the design point values on the Solar Field page. It does not use the value in simulation calculations.

Bellows shadowing

An optical derate factor accounting for the fraction of radiation lost after striking the mechanical bellows at the ends of the receiver tubes.

Dirt on receiver

An optical derate factor accounting for the fraction of radiation lost due to dirt and soiling on the receiver.

Total Weighted Losses

The total weighted losses are used in the solar field sizing calculations as an estimate of the optical and thermal losses in the solar field at the design point. SAM does not use the weighted loss variables in hourly simulations.

Heat loss at design

The total thermal loss expected from the active receiver type under design conditions accounting for the weighting fraction of the four receiver variations. SAM uses the value to calculate the design point total loop conversion efficiency and the solar field aperture area shown on the Solar Field page.

Optical derate

Represents the total optical losses expected from the active receiver type under design conditions accounting for the weighting fraction of the four receiver variations. SAM uses the value to calculate the design point total loop conversion efficiency and the solar field aperture area shown on the Solar Field page.

Variable	Equation	Note
Heat loss at design	$= \sum_{i=1}^{4} f_{weight,i} * \dot{q}_{hl,i}$	$f_{weight,i}$ is the weighting fraction for each variation
Optical derate	$= \sum_{i=1}^{4} f_{weight,i} * \eta_{bellows,i} * \eta_{rec,dirt,i} * \eta_{absorb,i} * \tau_{env,i}$	$\tau_{env,i}$ is the envelope transmittance

Specifying Receiver Type Variations

You can use the receiver variations to model a solar field with receivers in different conditions. If you want all of the receivers in the field to be identical, then you can use a single variation and assign it a variant weighting fraction of 1.

When you use more than one receiver variation, be sure that the sum of the four variant weighting fractions is 1.

Here's an example of an application of the receiver variations for a field that consists of a two receiver types. The first type, Type 1, represents receivers originally installed in the field. Type 2 represents replacement receivers installed as a fraction of the original receivers are damaged over time.

Over the life of the project, on average, 5 percent of the Type 1 receivers have broken glass envelopes, and another 5 percent have lost vacuum in the annulus. We'll also assume that degraded receivers are randomly distributed throughout the field -- SAM does not have a mechanism for specifying specific locations of different variations of a given receiver type. To specify this situation, we would start with Type 1, and use Variation 1 to represent the 90 percent of intact receivers, assigning it a variant weighting fraction of 0.90. We'll use Variation 2 for the 5 percent of receivers with broken glass envelopes, giving it a weighting fraction of 0.05, and Variation 3 for the other 5 percent of lost-vacuum receivers with a weighting fraction of 0.05. We'll assign appropriate values to the parameters for each of the two damaged receiver variations.

Next, we'll specify Type 2 to represent intact replacement receivers. We will us a single variation for the intact Type 2 receivers.

On the Solar Field page, we'll specify the single loop configuration (assuming a loop with eight assemblies), using Type 2 for the first and second assembly in the loop, and Type 1 receivers (with the variant weighting we assigned on the Receivers page) for the remaining six assemblies in the loop.

7.1.5 Power Cycle

To view the Power Cycle page, click **Power Cycle** on the main window's navigation menu. Note that for the physical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Physical Trough System.

The power cycle model represents a power block that converts thermal energy delivered by the solar field and optional thermal energy system to electric energy using a conventional steam Rankine cycle power plant.

The power cycle can use either an evaporative cooling system for wet cooling, or an air-cooled system for dry cooling.

The power cycle may include a fossil-fired backup boiler that heats the heat transfer fluid before it enters the power cycle during times when there is insufficient solar energy to drive the power cycle at its design load.

The power cycle model for the SAM physical trough model is the same as that used for the power tower model. For a detailed description of the power cycle model, see Chapter 4 of Wagner M, 2008. *Simulation and Predictive Performance Modeling of Utility-Scale Central Receiver System Power Plants*. Master of Science Thesis. University of Wisconsin-Madison. http://sel.me.wisc.edu/publications/theses/wagner08.zip.

> **Note.** For a detailed explanation of the physical trough model, see Wagner, M. J.; Gilman, P. (2011). *Technical Manual for the SAM Physical Trough Model*. 124 pp.; NREL Report No. TP-5500-51825. http://www.nrel.gov/docs/fy11osti/51825.pdf (3.7 MB)

Contents

- Input Variable Reference describes the input variables and options on the Power Cycle page.

- [Modeling a Fossil-fired Backup Boiler] describes the steps for including a backup boiler in the system.

Input Variable Reference

Plant Capacity

Design gross output (MWe)

The power cycle's design output, not accounting for parasitic losses. SAM uses this value to size system components, such as the solar field area when you use the solar multiple to specify the solar field size.

Estimated gross to net conversion factor

An estimate of the ratio of the electric energy delivered to the grid to the power cycle's gross output. SAM uses the factor to calculate the power cycle's nameplate capacity for capacity-related calculations, including the estimated total cost per net capacity value on the Trough System Costs page, capacity-based incentives on the Incentives page, and the capacity factor reported in the results.

Estimated net output design (nameplate) (MWe)

The power cycle's nameplate capacity, calculated as the product of the design gross output and estimated gross to net conversion factor.

Estimated Net Output at Design (MWe) = Design Gross Output (MWe) × Estimated Gross to Net Conversion Factor

Power Block Design Point

Rated cycle conversion efficiency

The thermal to electric conversion efficiency of the power cycle under design conditions.

Design inlet temperature (ºC)

The heat transfer fluid temperature at the power cycle inlet under design conditions. This value is the design loop outlet temperature from the Solar Field page.

Design outlet temperature (ºC)

The heat transfer fluid temperature at the power cycle outlet under design conditions. This value is the design loop inlet temperature from the Solar Field page.

Boiler operating pressure (bar)

The steam pressure in the main Rankine cycle boiler at design, used to calculate the steam saturation temperature in the boiler, and thus the driving heat transfer temperature difference between the inlet heat transfer fluid and the steam in the boiler.

Steam cycle blowdown fraction

The fraction of the steam mass flow rate in the power cycle that is extracted and replaced by fresh water. This fraction is multiplied by the steam mass flow rate in the power cycle for each hour of plant operation to determine the total required quantity of power cycle makeup water. The blowdown fraction accounts for water use related directly to replacement of the steam working fluid. The default value of 0.013 for the wet-cooled case represents makeup due to blowdown quench and steam cycle makeup during operation and startup. A value of 0.016 is appropriate for dry-cooled systems to account for additional wet-surface air cooling for critical Rankine cycle components.

Fossil backup boiler LHV efficiency

The back-up boiler's lower heating value efficiency, used to calculate the quantity of gas required by the back-up boiler for hours that the fossil backup system supplements solar energy from the solar field or thermal storage system.

The **boiler LHV efficiency** value determines the quantity of fuel used by the backup boiler. A value of 0.9 is reasonable for a natural gas-fired backup boiler. SAM includes the cost of fuel for the backup system in the levelized cost of energy and other metrics reported in the results, and reports the energy equivalent of the hourly fuel consumption in the time series simulation results. The cost of fuel for the backup boiler is defined on the Trough System Costs page.

The timing of the backup boiler's operation depends on the fossil fill fraction values from the Thermal Storage page. See Storage and Fossil Backup Dispatch Controls for details.

Aux heater outlet set temp (ºC)

The temperature set point for the auxiliary heaters for the fossil backup system.

Fossil Dispatch Mode

Determines how SAM operates the fossil backup system:

Minimum Backup Level:

In the Minimum Backup Level mode, whenever the **fossil fill fraction** is greater than zero for any dispatch period defined on the Thermal Storage page, the system is considered to include a fossil burner that heats the HTF before it is delivered to the power cycle.

In this mode, the fossil fill fraction defines the fossil backup as a function of the thermal energy from the solar field (and storage, if applicable) in a given hour and the **design turbine gross output**.

For example, for an hour with a fossil fill fraction of 1.0 when solar energy delivered to the power cycle is less than that needed to run at the power cycle design gross output, the backup heater would supply enough energy to "fill" the missing heat, and the power cycle would operate at the design gross output. If, in that scenario, solar energy (from either the field or storage system) is driving the power cycle at full load, the fossil backup would not operate. For a fossil fill fraction of 0.75, the heater would only be fired when solar output drops below 75% of the power cycle's design gross output.

Supplemental Operation:

In the Supplemental Operation mode, SAM assumes a fossil backup system of a fixed maximum capacity, for example, capable of supplying 10 MW of thermal energy to the HTF.

Heat capacity of balance of plant (kWht/ºC-MWhe)

A term to introduce additional thermal capacity into the solar field to account for thermal inertia effects not directly linked to the mass of heat transfer fluid in the solar field. The units for this value are thermal kilowatt-hours per megawatt of gross electric output capacity needed to raise the balance of plant temperature one degree Celsius.

Plant Control

Low resource standby period (hr)

During periods of insufficient flow from the heat source due to low thermal resource, the power block may enter standby mode. In standby mode, the cycle can restart quickly without the startup period required by a cold start. The standby period is the maximum number of hours allowed for standby mode. This option is only available for systems with thermal storage. Default is 2 hours.

Fraction of thermal power needed for standby

The fraction of the power cycle's design thermal input required from storage to keep the power cycle in standby mode. This thermal energy is not converted into electric power. SAM does not calculate standby energy for systems with no storage.

Power block startup time (hr)

The time in hours that the system consumes energy at the startup fraction before it begins producing electricity. If the startup fraction is zero, the system will operate at the design capacity during the startup time.

Fraction of thermal power needed for startup

The fraction of the turbine's design thermal input energy required during startup. This thermal energy is not converted to electric power.

Minimum required startup temp (ºC)

The temperature at which heat transfer fluid circulation through the power cycle heat exchangers begins, typically near the power block design heat transfer fluid outlet temperature.

Max turbine over design operation

The maximum allowable power cycle output as a fraction of the electric nameplate capacity. Whenever storage is not available and the solar resource exceeds the irradiation at design value from the Solar Field page, some collectors in the solar field are defocused to limit the power block output to the maximum load.

Min turbine operation

The fraction of the nameplate electric capacity below which the power cycle does not generate electricity. Whenever the power block output is below the minimum load and thermal energy is available from the solar field, the field is defocused. For systems with storage, solar field energy is delivered to storage until storage is full before the field is defocused.

Turbine Inlet Pressure Control

Determines the power cycle working fluid pressure during off-design loading.

Fixed Pressure: The power block maintains the design high pressure of the power cycle working fluid during off-design loading.

Sliding Pressure: The power block decreases the high pressure of the power cycle working fluid during off-design loading.

Cooling System

Condenser type

Choose either an air-cooled condenser (dry cooling), evaporative cooling (wet cooling), or hybrid cooling system.

In hybrid cooling a wet-cooling system and dry-cooling share the heat rejection load. Although there are many possible theoretical configurations of hybrid cooling systems, SAM only allows a parallel cooling option.

Hybrid Dispatch

For hybrid cooling, the hybrid dispatch table specifies how much of the cooling load should be handled by the wet-cooling system for each of 6 periods in the year. The periods are specified in the matrices on the Thermal Storage page. Each value in the table is a fraction of the design cooling load. For example, if you want 60% of heat rejection load to go to wet cooling in Period 1, type 0.6 for Period 1. Directing part of the heat rejection load to the wet cooling system reduces the total condenser temperature and improves performance, but increases the water requirement. SAM sizes the wet-cooling system to match the maximum fraction that you specify in the hybrid dispatch table, and sizes the air-cooling system to meet the full cooling load.

Ambient temp at design (ºC)

The ambient temperature at which the power cycle operates at its design-point-rated cycle conversion efficiency. For the air-cooled condenser option, use a dry bulb ambient temperature value. For the evaporative condenser, use the wet bulb temperature.

Ref Condenser Water dT (ºC)

For the evaporative type only. The temperature rise of the cooling water across the condenser under design conditions, used to calculate the cooling water mass flow rate at design, and the steam condensing temperature.

Approach temperature (ºC)

For the evaporative type only. The temperature difference between the circulating water at the condenser inlet and the wet bulb ambient temperature, used with the ref. condenser water dT value to determine the condenser saturation temperature and thus the turbine back pressure.

ITD at design point (ºC)

For the air-cooled type only. Initial temperature difference (ITD), difference between the temperature of steam at the turbine outlet (condenser inlet) and the ambient dry-bulb temperature.

Note. When you adjust the ITD, you are telling the model the conditions under which the system will achieve the thermal efficiency that you've specified. If you increase the ITD, you should also modify the thermal efficiency (and/or the design ambient temperature) to accurately describe the design-point behavior of the system. The off-design penalty in the modified system will follow once the parameters are corrected.

Condenser pressure ratio

For the air-cooled type only. The pressure-drop ratio across the air-cooled condenser heat exchanger, used to calculate the pressure drop across the condenser and the corresponding parasitic power required to maintain the air flow rate.

Min condenser pressure

The minimum condenser pressure in inches if mercury prevents the condenser pressure from dropping below the level you specify. In a physical system, allowing the pressure to drop below a certain point can result in physical damage to the system. For evaporative (wet cooling), the default value is 1.25 inches of mercury. For air-cooled (dry cooling), the default is 2 inches of mercury. For hybrid systems, you can use the dry-cooling value of 2 inches of mercury.

Cooling system part load levels

The cooling system part load levels tells the heat rejection system model how many discrete operating points there are. A value of 2 means that the system can run at either 100% or 50% rejection. A value of three means rejection operating points of 100% 66% 33%. The part load levels determine how the heat rejection operates under part load conditions when the heat load is less than full load. The default value is 2, and recommended range is between 2 and 10. The value must be an integer.

7.1.6 Thermal Storage

To view the Thermal Storage page, click **Thermal Storage** on the main window's navigation menu. Note that for the physical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Physical Trough System.

A thermal energy storage system (TES) stores heat from the solar field in a liquid medium. Heat from the storage system can drive the power block turbine during periods of low or no sunlight. A thermal storage system is beneficial in many locations where the peak demand for power occurs after the sun has set. Adding thermal storage to a parabolic trough system allows the collection of solar energy to be separated from the operation of the power block. For example, a system might be able to collect energy in the morning and use it to generate electricity late into the evening.

In direct storage systems, the solar field's heat transfer fluid itself serves as the storage medium. In indirect systems, a separate fluid is the storage fluid, and heat is transferred from the solar field's heat transfer fluid to the storage fluid through heat exchangers. The thermal storage system consists of one or more tank pairs, pumps to circulate the liquids, and depending on the design, heat exchangers. Each tank pair consists of a hot tank to store heat from the solar field, and a cold tank to store the cooled storage medium after the power block has extracted its energy.

Note. For more information on thermal energy storage systems for parabolic trough systems, see http://www.nrel.gov/csp/troughnet/thermal_energy_storage.html.

The storage system variables describe the thermal energy storage system. The thermal storage dispatch control variables determine when the system dispatches energy from the storage system, and from a fossil-fired backup system if the system includes one.

Note. For a detailed explanation of the physical trough model, see Wagner, M. J.; Gilman, P. (2011). *Technical Manual for the SAM Physical Trough Model*. 124 pp.; NREL Report No. TP-5500-51825. http://www.nrel.gov/docs/fy11osti/51825.pdf (3.7 MB)

Contents

Input Variable Reference

Storage System

Full Load Hours of TES (hours)

The thermal storage capacity expressed in number of hours of thermal energy delivered at the power block's design thermal input level. The physical capacity is the number of hours of storage multiplied by the power cycle design thermal input. Used to calculate the system's maximum storage capacity.

Storage volume (m^3)

SAM calculates the total heat transfer fluid volume in storage based on the storage hours at full load and the power block design turbine thermal input capacity. The total heat transfer fluid volume is divided among the total number of tanks so that all hot tanks contain the same volume of fluid, and all cold tanks contain the same volume of fluid. See Equations for Calcualated Values.

TES Thermal capacity (MWht)

The equivalent thermal capacity of the storage tanks, assuming the thermal storage system is fully charged. This value does not account for losses incurred through the heat exchanger for indirect storage systems. See Equations for Calcualated Values.

Parallel tank pairs

The number of parallel hot-cold storage tank pairs. Increasing the number of tank-pairs also increases the volume of the heat transfer fluid exposed to the tank surface, which increases the total tank thermal losses. SAM divides the total heat transfer fluid volume among all of the tanks, and assumes that each hot tank contains an equal volume of fluid, and each cold tank contains and equal volume.

Tank height (m)

The height of the cylindrical volume of heat transfer fluid in each tank.

Tank fluid min height (m)

The minimum allowable height of fluid in the storage tank(s). The mechanical limits of the tank determine this value.

Tank diameter (m)

The diameter of a storage tank, assuming that all tanks have the same dimensions. SAM calculates this value based on the specified height and storage volume of a single tank, assuming that all tanks have the same dimensions. See Equations for Calcualated Values.

Min fluid volume (m^3)

The volume of fluid in a tank that corresponds to the tank's minimum fluid height specified above. See Equations for Calcualated Values.

Tank loss coeff (W/m^2-K)

The thermal loss coefficient for the storage tanks. This value specifies the number of thermal watts lost from the tanks per square meter of tank surface area and temperature difference between the storage fluid bulk temperature and the ambient dry bulb temperature.

Estimated heat loss (MWt)

The estimated value of heat loss from all storage tanks. The estimate assumes that the tanks are 50% charged, so that the storage fluid is evenly distributed among the cold and hot tanks, and that the hot tank temperature is equal to the solar field hot (outlet) temperature, and the cold tank temperature is equal to the solar field cold (inlet) temperature. See Equations for Calcualated Values.

Cold and Hot tank heater set point (ºC)

The minimum allowable storage fluid temperature in the storage tanks. If the fluid temperature falls below the set point, the electric tank heaters deliver energy to the tanks, attempting to increase the temperature to the set point. SAM reports this energy in the performance model results as "Tank freeze protection energy."

Tank heater capacity (MWt)

The maximum rate at which heat can be added by the electric tank heaters to the storage fluid in the tanks.

Tank heater efficiency

The electrical to thermal conversion efficiency of the electric tank heaters.

Hot side HX approach temp (ºC)

Applies to systems with a heat exchanger only (indicated by a heat exchanger derate value of less than one). The temperature difference on the hot side of the solar-field-to-thermal-storage heat exchanger. During charge cycles, the temperature is the solar field hot outlet temperature minus the storage hot tank inlet temperature. During discharge cycles, it is defined as the storage hot tank temperature minus the power cycle hot inlet temperature.

Cold side HX approach temp (ºC)

Applies to systems with a heat exchanger only (indicated by a heat exchanger derate value less than one). The temperature difference on the cold side of the solar field-to-thermal-storage heat exchanger. During charge cycles, the temperature is the storage cold temperature (storage outlet) minus the heat exchanger cold temperature. During discharge cycles, it is the heat exchanger cold temperature minus the storage cold temperature (storage inlet).

Heat exchanger derate

A calculated value indicating the temperature derate caused by the heat exchanger approach temperatures. The derate factor is for reference only and not used in performance calculations. The derate is defined as the temperature difference between the hot and the cold field design temperatures minus the heat exchanger approach temperatures all divided by the difference between the hot and cold field design temperatures. A derate of one indicates a system that uses the same fluid for the solar field heat transfer fluid and for the storage fluid and therefore does not require a heat exchanger between the solar field and storage system. See Equations for Calcualated Values.

Initial TES Fluid temp (ºC)

The temperature of the storage fluid in the thermal energy storage system in the first time step of the simulation.

Storage HTF fluid

The storage fluid used in the thermal energy storage system.

When the storage fluid and solar field heat transfer fluid (HTF) are different, the system is an indirect system with a heat exchanger (heat exchanger derate is less than one).

When the storage fluid and solar field HTF are the same, the system is a direct system that uses the solar field HTF as the storage medium. For a direct system, SAM disables the **Hot side HX approach temp** and **Cold side HX approach temp** variables, and sets the **Heat exchanger derate** value to one. See the Solar Field page for table of fluid properties.

User-defined HTF fluid

When you choose user-defined from the Storage HTF fluid list, you can specify a table of material properties of a storage fluid. You must provide values for two temperatures (two rows of data) of specific heat, density, viscosity, and conductivity values. See Specifying a Custom Heat Transfer Fluid for details.

Storage HTF min operating temp (ºC)

The minimum HTF operating temperature recommended by the HTF manufacturer.

In some cases the minimum operating temperature may be the same as the fluid's freeze point. However, at the freeze point the fluid is typically significantly more viscous than at design operation temperatures, so it is likely that the "optimal" minimum operating temperature is higher than the freeze point.

Storage HTF max operating temp (ºC)

The minimum HTF operating temperature recommended by the HTF manufacturer.

Operation at temperatures above this value may result in degradation of the HTF and be unsafe. To avoid this, you may want to include a safety margin and use a maximum operating temperature value slightly lower than the recommended value.

Fluid Temperature (ºC)

A reference value indicating the temperature at which the substance properties are evaluated for thermal storage. See Equations for Calcualated Values.

TES fluid density (kg/m^3)

The density of the storage fluid at the fluid temperature, used to calculate the total mass of thermal fluid required in the storage system. See Equations for Calcualated Values.

TES specific heat (kJ/kg-K)

The specific heat of the storage fluid at the fluid temperature, used to calculate the total energy content of the fluid in the storage system. See Equations for Calcualated Values.

Equations for Calculated Values

The following table shows the equations SAM uses to calculate the values for the variables above that you cannot edit. (In Windows, the calculated values appear in blue.)

Variable	Equation	Note
Storage volume	$= \frac{t_{full\ load}}{\rho_{HTF} * c_{htf} * \left(T_{sf,out} - T_{sf,in}\right)} * 3.6e6$	$t_{full\ load}$ is the number of full-load hours of thermal storage
TES thermal capacity	$= \frac{W_{des,gross}}{\eta_{des}} * t_{full\ load}$	
Tank diameter	$= 2 * \sqrt{\frac{V_{TES}}{h_{tank} * \pi * N_{pairs}}}$	h_{tank} is the tank height; N_{pairs} is the number of tank pairs; V_{TES} is the Storage Volume

Min fluid volume	$= V_{TES} * \frac{h_{min}}{h_{tank}}$	
Estimated heat loss	$= \left(h_{tank} * \pi * D_{tank} + \pi * \left(\frac{D_{tank}}{2}\right)^2\right) * N_{pairs} * \left(T_{TES,ave} - 20\right) * C_{hl,tank}$	Equivalent to the product of the total interacting tank area, number of tank pairs, temperature difference with ambient, and heat loss coefficient
Heat exchanger derate	$= \frac{T_{hot,approach} + T_{cold,approach}}{T_{sf,out} - T_{sf,in}}$	
Fluid temperature	$= \frac{T_{sf,out} + T_{sf,in}}{2}$	Average fluid temperature for evaluating TES properties
TES fluid density		Lookup function for density, evaluated at Fluid temperature
TES specific heat		Lookup function for specific heat, evaluated at Fluid temperature

Thermal Storage Dispatch Control

The storage dispatch control variables each have six values, one for each of six possible dispatch periods. They determine how SAM calculates the energy flows between the solar field, thermal energy storage system, and power block. The fossil-fill fraction is used to calculate the energy from a backup boiler.

Storage Dispatch Fraction with Solar

The fraction of the TES maximum storage capacity indicating the minimum level of charge that the storage system can discharge to while the solar field is producing power. A value of zero will always dispatch the TES in any hour assigned to the given dispatch period; a value of one will never dispatch the TES. Used to calculate the storage dispatch levels.

Storage Dispatch Fraction without Solar

The fraction of the TES maximum storage capacity indicating the minimum level of charge that the storage system can discharge to while no solar resource is available. A value of zero will always dispatch the TES in any hour assigned to the given dispatch period; a value of one will never dispatch the TES. Used to calculate the storage dispatch levels.

Turbine Output Fraction

The fraction of design-point thermal load to the power block before part-load and temperature efficiency corrections. These values allow the user to dispatch the power cycle at a desired level according to the time-of-dispatch period. See Storage and Fossil Backup Dispatch Controls for details.

Fossil Fill Fraction

A fraction of the power block design turbine gross output from the Power Block page that can be met by the backup boiler. Used by the power block module to calculate the energy from the backup boiler. See Storage and Fossil Backup Dispatch Controls for details.

TOD Factor

The time-of-delivery (TOD) factors allow you to specify a set of TOD power price factors to model time-dependent pricing for projects with one of the Utility Financing options.

The TOD factors are a set of multipliers that SAM uses to adjust the PPA price based on time of day and month of year for utility projects. The TOD factors work in conjunction with the assumptions on the Financing page.

Note. For utility projects with no TOD factors, set the value for all periods to one.

For the CSP models, although the TOD power price factors are financial model inputs, they are on the Storage page because it includes other time-dependent variables, and there may be a relationship between the dispatch factors and the TOD power price factors. For PV and other technology models, the TOD power price factors are on a separate Time of Delivery Factors input page. For a description of how to specify the TOD power price factors for all technology models, see Time of Delivery Factors.

For a description of TOD-related simulation results, see PPA Revenue with TOD Factors.

Storage and Fossil Dispatch Controls

The thermal storage dispatch controls determine the timing of releases of energy from the thermal energy storage and fossil backup systems to the power block. When the system includes thermal energy storage or fossil backup, SAM can use a different dispatch strategy for up to six different dispatch periods.

Timing for Storage and Fossil Backup

SAM decides whether or not to operate the power cycle in each hour of the simulation based on how much energy is available in storage, how much energy is delivered by the solar field, and the values of the thermal storage dispatch control parameters. You can define a different dispatch strategy for each of six dispatch periods for weekdays and weekends. See Defining Dispatch Schedules for details. For each hour, SAM also decides whether to supplement solar energy with energy from the fossil backup system.

Storage Dispatch

For each hour in the simulation, SAM looks at the amount of energy in storage at the beginning of the hour and decides whether or not to operate the power cycle in that hour. For each dispatch period, there are two dispatch targets for starting or continuing to run the power cycle: one for periods of sunshine (**storage dispatch fraction w/solar**), and one for periods of no sunshine (**storage dispatch fraction w/o solar**). The dispatch target for each dispatch period is the product of the storage dispatch fraction for that period and the thermal storage capacity defined by the TES thermal capacity input variable.

- During periods of sunshine when there is insufficient energy from the solar field to drive the power cycle at its load requirement, the system dispatches energy from storage only when energy in storage is greater than or equal to the dispatch target.

- During periods of no sunshine, the power cycle will not run unless energy in storage is greater than or equal to the dispatch target.

The **turbine output fraction** for each dispatch period determines the power cycle output requirement for hours that fall within the dispatch period. A turbine output fraction of one defines an output requirement equivalent to the power cycle's design gross output defined on the Power Cycle page. For hours when the solar field energy is insufficient to drive the power cycle at the output requirement, the power cycle runs on energy from both the solar field and storage system. For hours when the solar field energy exceeds the output requirement, the power block runs at the required output level, and any excess energy goes to storage. If the storage system is at capacity, the collectors in the field defocus as specified on the Solar Field page to reduce the field's thermal output.

By setting the thermal storage dispatch control parameters, you can simulate a dispatch strategy for clear days when storage is at capacity that allows the operator to start the plant earlier in the day to avoid defocusing collectors in the field, for cloudy days that allows the operator to store energy for later use in a time period when the value of power is higher.

Fossil Fill

The **fossil fill fraction** defines the size of the fossil backup as a fraction of the power cycle design gross output. The quantity of fossil backup energy also depends on the **fossil backup boiler LHV efficiency**, **aux heater outlet set temp**, and **fossil dispatch mode parameters** on the Power Cycle page. is added to the input from the solar field and storage system.

Operation of the power block in a given hour with fossil backup is constrained by the **Turb out fraction** you specify for each period, and the **Max turbine over design operation** and **Min turbine operation** from the Power Cycle page. For hours that the added fossil energy is insufficient to meet the **Min turbine operation** requirement, fossil backup is not dispatched. For hours when the combined fossil and solar contribution exceeds the **Turb out fraction** for the hour, the amount of fossil energy dispatched is reduced until the required turbine output is met.

Defining Dispatch Schedules

The weekday and weekend dispatch schedules determine when each of the six dispatch periods apply during throughout the year. You can either choose an existing schedule from one of the schedules in the dispatch schedule library or define a custom schedule. For information about libraries, see Working with Libraries.

The dispatch schedule library only assigns period numbers to the weekday and weekend schedule matrices. The dispatch fractions that you specify are not stored in the library.

> **Note.** SAM also uses the dispatch schedules when you choose Hybrid Cooling on the Power Cycle page to assign hybrid dispatch fractions to the periods specified in the dispatch schedules..

To choose a schedule from the library:

1. Click **Dispatch schedule library**.
2. Choose a schedule from the list of four schedules. The schedules are based on time-of-use pricing schedules from four California utilities.
3. Click **OK**.

   You can modify a schedule using the steps described below. Modifying a schedule does not affect the schedule stored in the library.

4. For each of the up to six periods used in the schedule, enter values for the dispatch fractions (see Storage and Fossil Backup Dispatch Controls) described above. Use the period number and color to identify the times in the schedule that each period applies.

To specify a weekday or weekend schedule:

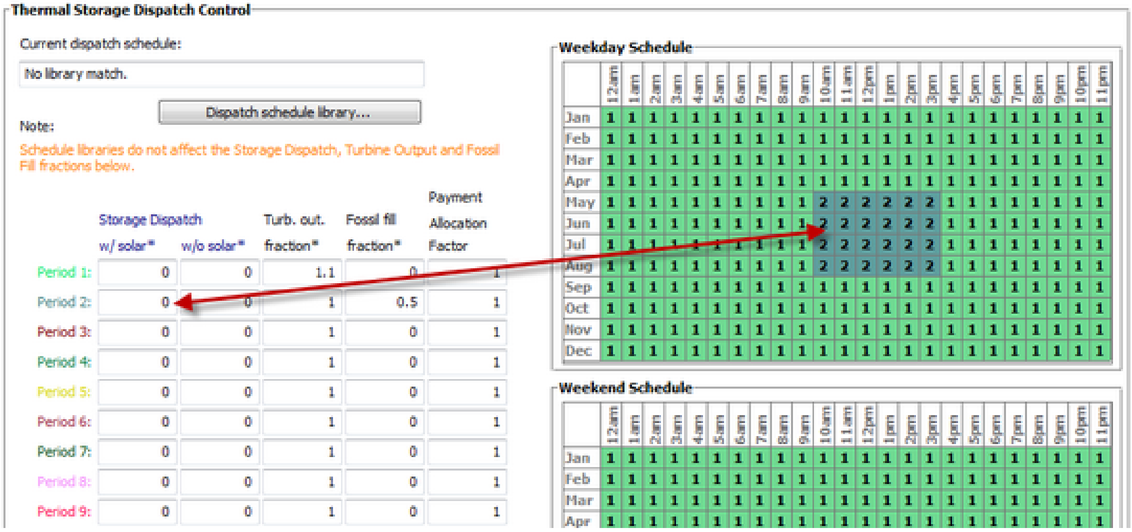
1. Assign values as appropriate to the Storage Dispatch, Turbine Output Fraction, Fossil Fill Fraction, and TOD Factor for each of the up to nine periods.
2. Click **Dispatch schedule library**.
3. Choose a **Uniform Dispatch**.
4. Click **OK**.
5. Use your mouse to draw a rectangle in the matrix for the first block of time that applies to period 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

6. Type the number 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

7. SAM shades displays the period number in the squares that make up the rectangle, and shades the rectangle to match the color of the period.



8. Repeat Steps 2-4 for each of the remaining periods that apply to the schedule.

7.1.7 Parasitics

To view the Parasitics page, click **Parasitics** on the main window's navigation menu. Note that for the physical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Physical Trough System.

The variables on the Parasitics page define electrical loads in the system. For each hour of the simulation, SAM calculates the parasitic load and subtracts it from the power cycle's gross electrical output to calculate the net electrical output.

Note. For a detailed explanation of the physical trough model, see Wagner, M. J.; Gilman, P. (2011). *Technical Manual for the SAM Physical Trough Model*. 124 pp.; NREL Report No. TP-5500-51825. http://www.nrel.gov/docs/fy11osti/51825.pdf (3.7 MB)

Parasitics

Piping thermal loss coefficient (W/m^2-K)

The thermal loss coefficient that is used to calculate thermal losses from piping between receivers, crossover piping, header piping, and runner piping. The coefficient specifies the number of thermal watts lost from the system as a function of the piping surface area, and the temperature difference between the fluid in the piping and the ambient air (dry bulb temperature). The length of crossover piping depends on the row spacing variable on the Solar Field page, and the piping distance between assemblies on the Collectors page.

Tracking power (W per collector)

The amount of electrical power consumed by a single collector tracking mechanism. SAM only calculates tracking losses during hours when collectors are actively tracking the sun. The total field tracking power is calculated by multiplying this value by the number of loops in the field and number of assemblies per loop specified on the Solar Field page.

Required pumping power for HTF through power block (kJ/kg)

A coefficient used to calculate the electric power required to pump heat transfer fluid through the power cycle. SAM applies the coefficient to all heat transfer fluid flowing through the power cycle. The coefficient can alternatively be defined as the pumping power divided by the mass flow rate kW/kg-s, which is equivalent to the units kJ/kg.

Required pumping power for HTF through storage (kJ/kg)

A coefficient used to calculate the electric power consumed by pumps to move heat transfer fluid through the storage heat exchanger on both the solar field side and the storage tank side (for cases where a heat exchanger exists, specified on the Thermal Storage page). This coefficient is applied separately to the solar field flow and the tank flow.

Fraction of rated gross power consumed at all times

A fixed electric load applied to all hours of the simulation, expressed as a fraction of rated gross power at design from the Power Cycle page.

Balance of plant parasitic (MWe/MWcap)

A parasitic load that is applied as a function of the thermal input to the power cycle.

Aux heater, boiler parasitic (MWe/MWcap)

A parasitic load that is applied as a function of the thermal output of the auxiliary fossil-fired heaters. Applies only when the system includes fossil backup. See the fossil backup inputs on the Power Cycle page.

Design Point Total Tracking (W)

A value displayed for reference indicating what the total tracking parasitic load would be if all collectors in the field were actively tracking simultaneously.

Design Point Total Fixed (MWe)

The value of the fixed parasitic load applied at all times.

Fixed (MWe) = Fraction of Gross Power Consumed at All Times × Design Gross Output (MWe)

Design Point Total BOP (MWe)

The value of the balance-of-plant parasitic load assuming design-point operation.

Design Point Total Aux (MWe)

The value of the auxiliary heater (for the backup gas boiler) parasitic load assuming the auxiliary heater is providing 100% of the thermal load required for the power cycle.

Design Point Totals

The design point total values represent the maximum limit of parasitic losses. SAM calculates actual parasitic losses during simulations.

Variable	Equation	Note
Tracking	$= N_{SCA} * N_{loops} * C_{tracking}$	
Fixed	$= W_{des,gross} * C_{fixed}$	
BOP	$= W_{des,gross} * C_{BOP}$	Only multiply gross power by the first coefficient

Aux	$= W_{des,gross} * C_{aux}$	Only multiply gross power by the first coefficient

7.2 Parabolic Trough Empirical

The empirical trough model models the same type of parabolic trough system as the physical trough model, but uses a set of curve-fit equations derived from regression analysis of data measured from the SEGS projects in the southwestern United States, so you are limited to modeling systems composed of components for which there is measured data. The model is based on Excelergy, originally developed for internal use at at the National Renewable Energy Laboratory.

For a general description of the model, see Overview.

The parabolic trough input pages for this option described in this section are:

- Trough System Costs
- Solar Field
- SCA / HCE (solar collector assembly / heat collection element)
- Power Block
- Thermal Storage
- Parasitics

7.2.1 Trough Empirical Overview

A parabolic trough system is a type of concentrating solar power (CSP) system that collects direct normal solar radiation and converts it to thermal energy that runs a power block to generate electricity. The components of a parabolic trough system are the solar field, power block, and in some cases, thermal energy storage and fossil backup systems. The solar field collects heat from the sun and consists of parabolic, trough-shaped solar collectors that focus direct normal solar radiation onto tubular receivers. Each collector assembly consists of mirrors and a structure that supports the mirrors and receivers, allows it to track the sun on one axis, and can withstand wind-induced forces. Each receiver consists of a metal tube with a solar radiation absorbing surface in a vacuum inside a coated glass tube. A heat transfer fluid (HTF) transports heat from the solar field to the power block (also called power cycle) and other components of the system. The power block is based on conventional power cycle technology, using a turbine to convert thermal energy from the solar field to electric energy. The optional fossil-fuel backup system delivers supplemental heat to the HTF during times when there is insufficient solar energy to drive the power block at its rated capacity.

The empirical parabolic trough model uses a set of equations based on empirical analysis of data collected from installed systems (the SEGS projects in the southwestern United States) to represent the performance of parabolic trough components. The model is based on Excelergy, a model initially developed for internal use at at the National Renewable Energy Laboratory. For information about the physical parabolic trough model, see Parabolic Trough Physical.

For a more detailed description of the empirical trough model, please download the draft empirical trough reference manual from the SAM website's support page: https://sam.nrel.gov/reference. You can also explore the source code written in FORTRAN for the empirical trough model in the following folder of your SAM installation folder (c:\SAM\SAM 2014.1.14 by default): C:\exelib\trnsys\source. The empirical trough model files are:

- Solar Field and SCA/HCE: sam_trough_model_type805.f90
- Power Block: sam_trough_plant_type807.f90
- Thermal Storage: sam_trough_storage_type806.f90
- Parasitics: sam_trough_plant_type807.f90

Note. Many of the input variables in the parabolic trough model are interrelated and should be changed together. For example, the storage capacity, which is expressed in hours of thermal storage, should not be changed without changing the tank heat loss value, which depends on the size of the storage system. Some of these relationships are described in this documentation, but not all.

The parabolic trough input pages for this option described in this section are:

- Trough System Costs
- Solar Field
- SCA / HCE (solar collector assembly / heat collection element)
- Power Block
- Thermal Storage
- Parasitics

7.2.2 Solar Field

To view the Solar Field page, click **Solar Field** on the main window's navigation menu. Note that for the empirical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Empirical Trough System.

The Solar Field page displays variables and options that describe the size and properties of the solar field, properties of the heat transfer fluid, reference design specifications of the solar field, and collector orientation.

Contents

Input Variable Reference

Field Layout

Options 1 and 2

For Option 1, (solar multiple mode), you specify a value for **Solar Multiple**, and SAM calculates the solar field area and displays it under **Calculated Values** as **Aperture Reflective Area**. In this mode, SAM ignores the solar field area value under **Field Layout**.

For Option 2 (solar field area mode), you specify a value for **Solar Field Area**, and SAM calculates the solar multiple and displays it under **Calculated Values**. In this mode, SAM ignores the Solar Multiple value under **Field Layout**.

See Sizing the Solar Field for details.

Distance Between SCAs in Row (m)

The end-to-end distance in meters between SCAs (solar collection elements, or collectors) in a single row, assuming that SCAs are laid out uniformly in all rows of the solar field. SAM uses this value to calculate the end loss. This value is not part of the SCA library on the SCA / HCE page, and should be verified manually to ensure that it is appropriate for the SCA type that appears on the SCA / HCE page.

Row spacing, center-to-center (m)

The centerline-to-centerline distance in meters between rows of SCAs, assuming that rows are laid out uniformly throughout the solar field. SAM uses this value to calculate the row-to-row shadowing loss factor. This value is not part of the SCA library, and should be verified manually to ensure that it is appropriate for the SCA type that appears on the SCA / HCE page.

Number of SCAs per Row

The number of SCAs in each row, assuming that each row in the solar field has the same number of SCAs. SAM uses this value in the SCA end loss calculation.

Deploy Angle (degrees)

The SCA angle during the hour of deployment. A deploy angle of zero for a northern latitude is vertical facing due east. SAM uses this value along with sun angle values to determine whether the current hour of simulation is the hour of deployment, which is the hour before the first hour of operation in the morning. SAM assumes that this angle applies to all SCAs in the solar field.

Stow Angle (degrees)

The SCA angle during the hour of stow. A stow angle of zero for a northern latitude is vertical facing east, and 180 degrees is vertical facing west. SAM uses this value along with the sun angle values to determine whether the current hour of simulation is the hour of stow, which is the hour after the final hour of operation in the evening.

Heat Transfer Fluid

Solar Field HTF Type

The heat transfer fluid (HTF) used in the heat collection elements and headers of the solar field. SAM includes the following options in the HTF library: Solar salt, Caloria, Hitec XL, Therminol VP-1, Hitec salt, Dowtherm Q, Dowtherm RP, Therminol 59, and Therminol 66. You can also define your own HTF using the user-defined HTF fluid option.

Note. During simulations, SAM counts the number of instances that the HTF temperature falls outside of the operating temperature limits in the table below. If the number of instances exceeds 50, it displays a simulation warning message on the Results page with the HTF temperature and time step number for the 50th instance.

Heat transfer fluids on the Field HTF Fluid list.

Name	Type	Min Optimal Operating Temp ºC	Max Optimal Operating Temp* ºC	Freeze Point ºC	Comments
Hitec Solar Salt	Nitrate Salt	238	593	238	
Hitec	Nitrate Salt	142	538	142	
Hitec XL	Nitrate Salt	120	500	120	
Caloria HT 43	Mineral Hydrocarbon	-12	315	-12 (pour point)	used in first Luz trough plant, SEGS I
Therminol VP-1	Mixture of Biphenyl and Diphenyl Oxide	12	400	12 (crystallization point)	Standard for current generation oil HTF systems
Therminol 59	Synthetic HTF	-45	315	-68 (pour point)	
Therminol 66	?	0	345	-25 (pour point)	
Dowtherm Q	Synthetic Oil	-35	330	n/a	
Dowtherm RP	Synthetic Oil	n/a	330	n/a	

*The maximum optimal operating temperature is the value reported as "maximum bulk temperature" on the product data sheets.

Data Sources for HTF Properties

Hitec fluids: Raade J, Padowitz D, Vaughn J. Low Melting Point Molten Salt Heat Transfer Fluid with Reduced Cost. Halotechnics. Presented at SolarPaces 2011 in Granada, Spain.

Caloria HT 43: Product comparison tool on Duratherm website.

Therminol Fluids: Solutia Technical Bulletins 7239115C, 7239271A, 7239146D.

Dowtherm Fluids: Dow Data Sheet for Q, no data sheet available for RP (high temp is from website): http://www.dow.com/heattrans/products/synthetic/dowtherm.htm).

Property table for user-defined HTF

When the Solar Field HTF type is "User-defined," click Edit to enter properties of a custom HTF.

Solar Field Inlet Temp (ºC)

Design temperature of the solar field inlet in degrees Celsius used to calculate design solar field average temperature, and design HTF enthalpy at the solar field inlet. SAM also limits the solar field inlet temperature to this value during operation and solar field warm up, and uses this value to calculate the actual inlet temperature when the solar field energy is insufficient for warm-up.

Solar Field Outlet Temp (ºC)

Design temperature of the solar field outlet in degrees Celsius, used to calculate design solar field average temperature. It is also used to calculate the design HTF enthalpy at the solar field outlet, which SAM uses to determine whether solar field is operating or warming up. SAM also uses this value to calculate the actual inlet temperature when the solar field energy is insufficient for warm-up.

Solar Field Initial Temp (ºC)

Initial solar field inlet temperature. The solar field inlet temperature is set to this value for hour one of the simulation.

Piping Heat Losses @ Design Temp (W/m²)

Solar field piping heat loss in Watts per square meter of solar field area when the difference between the average solar field temperature and ambient temperature is 316.5ºC. Used in solar field heat loss calculation.

Piping Heat Loss Coeff (1-3)

These three values are used with the solar field piping heat loss at design temperature to calculate solar field piping heat loss.

Solar Field Piping Heat Losses (W/m²)

Design solar field piping heat losses. This value is used only in the solar field size equations. This design value different from the hourly solar field pipe heat losses calculated during simulation.

$$\text{Solar Field Piping Heat Losses} = (PHLTC3 \times \Delta T^3 + PHLTC2 \times \Delta T^2 + PHLTC1 \times \Delta T) \times \text{Solar Field Piping Heat Losses @ Design } T$$

$$\Delta T = \text{Average Solar Field Temperature} - \text{Ambient Temp}$$

$$\text{Average Solar Field Temperature} = (\text{Solar Field Inlet Temp} + \text{Solar Field Outlet Temp}) \div 2$$

Where PHLTC1-3 are the Piping Heat Loss Coefficients you specify, and the temperature value are design point values that you specify as inputs. During simulations, SAM calculates the actual piping heat losses using simulated field temperatures and the ambient temperature from the weather file you specify on the Location and Resource page.

Minimum HTF Temp (ºC)

Minimum heat transfer fluid temperature in degrees Celsius. SAM automatically populates the value based on the properties of the solar field HTF type, i.e., changing the HTF type changes the minimum HTF temperature. The value determines when freeze protection energy is required, is used to calculate HTF enthalpies for the freeze protection energy calculation, and is the lower limit of the average solar field temperature. SAM assumes that heat protection energy is supplied by electric heat trace equipment.

HTF Gallons Per Area (gal/m²)

Volume at 25°C of HTF per square meter of solar field area, used to calculate the total mass of HTF in the solar field, which is used to calculate solar field temperatures and energies during hourly simulations. The volume includes fluid in the entire system including the power block and storage system if applicable. Example values are: SEGS VI: 115,000 gal VP-1 for a 188,000 m2 solar field is 0.612 gal/m2, SEGS VIII 340,500 gal VP-1 and 464,340 m2 solar field is 0.733 ga/m2.

Land Area

Solar Field Land Area (m²)

The actual aperture area converted from square meters to acres:

Solar Field Area (acres) = Actual Aperture (m^2) × Row Spacing (m) / Maximum SCA Width (m) × 0.0002471 (acres/m^2)

The maximum SCA width is the aperture width of SCA with the widest aperture in the field, as specified in the loop configuration and on the Collectors (SCA) page.

Non-Solar Field Land Area Multiplier

Land area required for the system excluding the solar field land area, expressed as a fraction of the solar field aperture area. A value of one would result in a total land area equal to the total aperture area. The default value is 1.4.

Total Land Area (acres)

Land area required for the entire system including the solar field land area

Total Land Area (acres) = Solar Field Area (acres) × (1 + Non-Solar Field Land Area Multiplier)

The land area appears on the System Costs page, where you can specify land costs in dollars per acre.

Solar Multiple (Design Point)

Note. The ambient temperature, direct normal radiation, and wind velocity reference variables differ from the hourly weather data that SAM uses for system output calculations. SAM uses the reference ambient condition variables to size the solar field. Hourly data from the weather file shown on the Location and Resource page determine the solar resource at the site.

Calculated Values

The two calculated values variables depend on whether you choose Option 1 or Option 2 to specify the solar field size. When you choose Option 1, the solar multiple calculated value is equal to the value you specify under **Field Layout** and SAM calculates the aperture reflective area. When you choose Option 2, the aperture reflective area is equal to the Solar Field Area value you specify, and SAM calculates the solar multiple.

Solar Multiple

The solar field area expressed as a multiple of the exact reflective area for a solar multiple of 1 (see "Reference Conditions (SM=1)" below). SAM uses the calculated solar multiple value to calculate the design solar field thermal energy and the maximum thermal energy storage charge rate.

Solar Multiple = Aperture Reflective Area ÷ Exact Aperture Reflective Area at SM=1

Aperture Reflective Area (m^2)

The total reflective area of collectors in solar field expressed in square meters. SAM uses this value in the delivered thermal energy calculations. This area is the total collection aperture area, which is less than the mirror area. The solar field area does not include space between collectors or the land required by the power block.

Aperture Reflective Area = Solar Multiple × Exact Aperture Reflective Area at SM=1

Solar Multiple Reference Conditions

Ambient Temp (ºC)

Reference ambient temperature in degrees Celsius. Used to calculate the design solar field pipe heat losses.

Direct Normal Radiation (W/m²)

Reference direct normal radiation in Watts per square meter. Used to calculate the solar field area that would be required at this insolation level to generate enough thermal energy to drive the power block at the design turbine thermal input level. SAM also uses this value to calculate the design HCE heat losses displayed on the SCA / HCE page. The appropriate value depends on the system location. For example, 950 W/m2 is an appropriate value for the Mohave Desert and typical locations under consideration for development in the U.S., and 800 W/m2 is appropriate for southern Spain. See Sizing the Solar Field for more information.

Note. Direct Normal Radiation does not represent weather conditions at the site, but is the reference radiation value used to calculate the solar field area when the solar multiple is one. The radiation values used during simulation are from the weather file specified on the Location and Resource page.

Wind Velocity (m/s)

Reference wind velocity in meters per second. SAM uses this value to calculate the design HCE heat losses displayed on the SCA / HCE page.

Reference Condition (SM=1)

Exact Aperture Reflective Area (m²)

The solar field area required to deliver sufficient solar energy to drive the power block at the design turbine gross output level under reference weather conditions. It is equivalent to a solar multiple of one, and used to calculate the solar field area when the Layout mode is Solar Multiple.

Exact Aperture Reflective Area = Design Turbine Thermal Input
÷ (Direct Normal Radiation × Optical Efficiency
- HCE Thermal Losses
- Solar Field Piping Heat Losses)

Exact Num. SCAs

The exact aperture reflective area divided by the SCA aperture reflective area. SAM uses the nearest integer greater than or equal to this value in the solar field size equations to calculate value of the Aperture Reflective Area variable described above. The exact number of SCAs represents the number of SCAs in a solar field for a solar multiple of one.

Exact Num SCAs = Exact Aperture Reflective Area ÷ Aperture Area per SCA

Values from Other Pages

Aperture Area per SCA (m²)

SCA aperture reflective area variable from the SCA / HCE page. SAM uses this value in the solar field size equations to calculate the value of the Aperture Reflective Area variable described above.

HCE Thermal Losses (W/m²)

Design HCE thermal losses based on the heat loss parameters from the SCA / HCE page. SAM uses this value only in the solar field size equations. This design value is different from the hourly HCE thermal losses calculated during simulation.

Optical Efficiency

Weighted optical efficiency variable from the SCA / HCE page. SAM uses this design value only in the solar field size equations. This design value is different from SCA efficiency factor calculated during simulations.

Design Turbine Thermal Input (MWt)

Design turbine thermal input variable from the Power Block page. Used to calculate the exact aperture reflective area described above.

Orientation

Collector Tilt (degrees)

The collector angle from horizontal, where zero degrees is horizontal. A positive value tilts up the end of the array closest to the equator (the array's south end in the northern hemisphere), a negative value tilts down the southern end. Used to calculate the solar incidence angle and SCA tracking angle. SAM assumes that the SCAs are fixed at the tilt angle.

Collector Azimuth (degrees)

The azimuth angle of the collector, where zero degrees is pointing toward the equator, equivalent to a north-south axis. Used to calculate the solar incidence angle and the SCA tracking angle. SAM calculates the SCAs' tracking angle for each hour, assuming that the SCAs are oriented 90 degrees east of the azimuth angle in the morning and track the daily movement of the sun from east to west.

Sizing the Solar Field

Sizing the solar field of a parabolic trough system in SAM involves determining the optimal solar field aperture area for a system at a given location. In general, increasing the solar field area increases the system's electric output, thereby reducing the project's LCOE. However, during times there is enough solar resource, too large of a field will produce more thermal energy than the power block and other system components can handle. Also, as the solar field size increases beyond a certain point, the higher installation and operating costs outweigh the benefit of the higher output.

An optimal solar field area should:

- Maximize the amount of time in a year that the field generates sufficient thermal energy to drive the power block at its rated capacity.
- Minimize installation and operating costs.
- Use thermal energy storage and fossil backup equipment efficiently and cost effectively.

The problem of choosing an optimal solar field area involves analyzing the tradeoff between a larger solar field that maximizes the system's electrical output and project revenue, and a smaller field that minimizes installation and operating costs.

The levelized cost of energy (LCOE) is a useful metric for optimizing the solar field size because it includes the amount of electricity generated by the system, the project installation costs, and the cost of operating and maintaining the system over its life. Optimizing the solar field involves finding the solar field aperture area that results in the lowest LCOE. For systems with thermal energy storage systems, the optimization involves finding the combination of field area and storage capacity that results in the lowest LCOE.

Option 1 and Option 2

SAM provides two options for specifying the solar field aperture area: Option 1 (solar multiple) allows you to specify the solar field area as a multiple of the power block's rated capacity (design gross output), and Option 2 (field aperture) allows you to specify the solar field aperture area as an explicit value in square meters.

- Option 1: You specify a solar multiple, and SAM calculates the solar field aperture area required to meet power block rated capacity.
- Option 2: You specify the aperture area independently of the power block's rated capacity.

If your analysis involves a known solar field area, you should use Option 2 to specify the solar field aperture area explicitly.

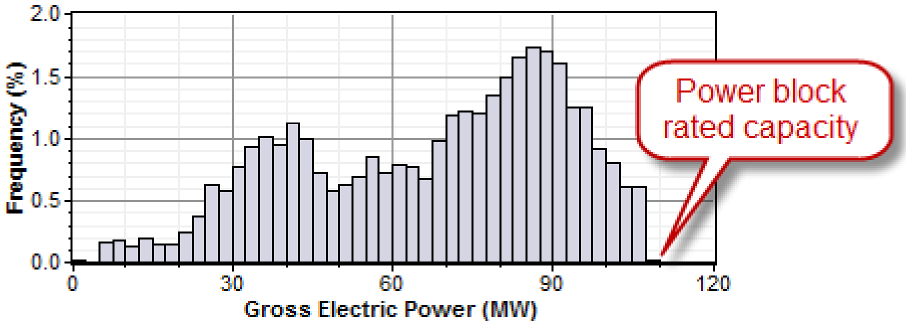
If your analysis involves optimizing the solar field area for a specific location, or choosing an optimal combination of solar field aperture area and thermal energy storage capacity, then you should choose Option 1, and follow the procedure described below to size the field.

Solar Multiple

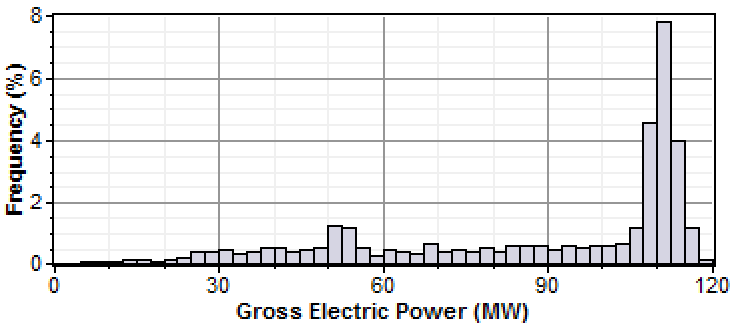
The solar multiple makes it possible to represent the solar field aperture area as a multiple of the power block rated capacity. A solar multiple of one (SM=1) represents the solar field aperture area that, when exposed to solar radiation equal to the design radiation value (irradiation at design), generates the quantity of thermal energy required to drive the power block at its rated capacity (design gross output), accounting for thermal and optical losses.

Because at any given location the number of hours in a year that the actual solar resource is equal to the design radiation value is likely to be small, a solar field with SM=1 will rarely drive the power block at its rated capacity. Increasing the solar multiple (SM>1) results in a solar field that operates at its design point for more hours of the year and generates more electricity.

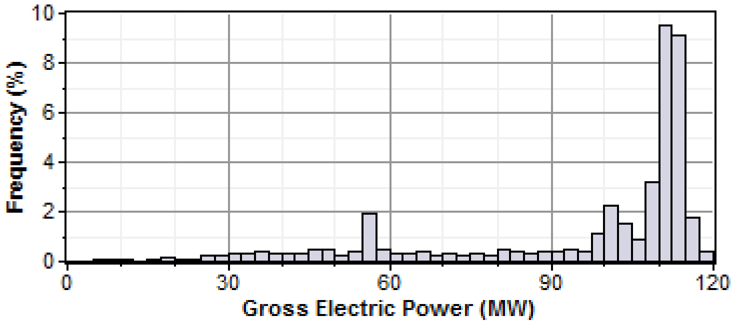
For example, consider a system with a power block design gross output rating of 111 MW and a solar multiple of one (SM=1) and no thermal storage. The following frequency distribution graph shows that the power block never generates electricity at its rated capacity, and generates less than 80% of its rated capacity for most of the time that it generates electricity:



For the same system with a solar multiple chosen to minimize LCOE (in this example SM=1.5), the power block generates electricity at or slightly above its rated capacity almost 15% of the time:



Adding thermal storage to the system changes the optimal solar multiple, and increases the amount of time that the power block operates at its rated capacity. In this example, the optimal storage capacity (full load hours of TES) is 3 hours with SM=1.75, and the power block operates at or over its rated capacity over 20% of the time:



Note. For clarity, the frequency distribution graphs above exclude nighttime hours when the gross power output is zero.

Reference Weather Conditions for Field Sizing

The design weather conditions values are reference values that represent the solar resource at a given location for solar field sizing purposes. The field sizing equations require three reference condition variables:

- Ambient temperature
- Direct normal irradiance (DNI)
- Wind velocity

The values are necessary to establish the relationship between the field aperture area and power block rated capacity for solar multiple (SM) calculations.

Note. The design values are different from the data in the weather file. SAM uses the design values to size the solar field before running simulations. During simulations, SAM uses data from the weather file you choose on the Location and Resource page.

The reference ambient temperature and reference wind velocity variables are used to calculate the design heat losses, and do not have a significant effect on the solar field sizing calculations. Reasonable values for those two variables are the average annual measured ambient temperature and wind velocity at the project location. For the physical trough model, the reference temperature and wind speed values are hard-coded and cannot be changed. The linear Fresnel and generic solar system models allow you to specify the reference ambient temperature value, but not the wind speed. The empirical trough model allows you to specify both the reference ambient temperature and wind speed values.

The reference direct normal irradiance (DNI) value, on the other hand, does have a significant impact on the solar field size calculations. For example, a system with reference conditions of 25°C, 950 W/m^2, and 5 m/s (ambient temperature, DNI, and wind speed, respectively), a solar multiple of 2, and a 100 MWe power block, requires a solar field area of 871,940 m^2. The same system with reference DNI of 800 W/m^2 requires a solar field area of 1,055,350 m^2.

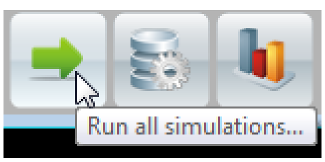
In general, the reference DNI value should be close to the maximum actual DNI on the field expected for the location. For systems with horizontal collectors and a field azimuth angle of zero in the Mohave Desert of the United States, we suggest a design irradiance value of 950 W/m2. For southern Spain, a value of 800 W/m2 is reasonable for similar systems. However, for best results, you should choose a value for your specific location using one of the methods described below.

Linear collectors (parabolic trough and linear Fresnel) typically track the sun by rotating on a single axis, which means that the direct solar radiation rarely (if ever) strikes the collector aperture at a normal angle. Consequently, the DNI incident on the solar field in any given hour will always be less than the DNI value in the resource data for that hour. The cosine-adjusted DNI value that SAM reports in simulation results is a measure of the incident DNI.

Using too low of a reference DNI value results in excessive "dumped" energy: Over the period of one year, the actual DNI from the weather data is frequently greater than the reference value. Therefore, the solar field sized for the low reference DNI value often produces more energy than required by the power block, and excess thermal energy is either dumped or put into storage. On the other hand, using too high of a reference DNI value results in an undersized solar field that produces sufficient thermal energy to drive the power block at its design point only during the few hours when the actual DNI is at or greater than the reference value.

To choose a reference DNI value:

1. Choose a weather file on the Location and Resource page.
2. Enter values for collector tilt and azimuth.
3. For systems with storage, specify the storage capacity and maximum storage charge rate defined on the Thermal Storage page.
4. Click run all simulations, or press Ctrl-G.



5. On the Results page, click Time Series.
6. On the Time Series tab, click Zoom to Fit (at the bottom of the input page).

Method 1: Maximum Cosine-adjusted DNI

7. Clear all of the check boxes and check DNI-cosine effect product (W/m2) variable.
8. Read the maximum annual value from the graph, and use this value for the reference DNI.

Method 2: Minimize "Dumped" Energy

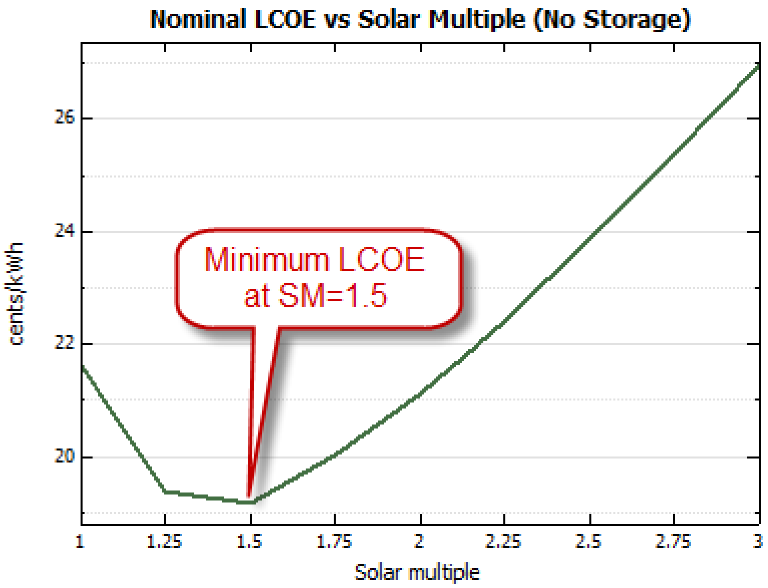
7. Clear all of the check boxes and check the dumped thermal energy variable(s).
8. If the amount of dumped thermal energy is excessive, try a lower value for the reference DNI value and run simulations again until the quantity of dumped energy is acceptable.

Optimizing the Solar Multiple

Representing the solar field aperture area as a solar multiple (Option 1) makes it possible to run parametric simulations in SAM and create graphs of LCOE versus solar multiple like the ones shown below. You can use this type of graph to find the optimal solar multiple.

For a parabolic trough system with no storage, the optimal solar multiple is typically between 1.4 and 1.5.

The graph shown below is for a system with no storage in Blythe, California, the optimal solar multiple is 2, meaning that the solar field aperture area should be chosen to be twice the area required to drive the power cycle at its rated capacity:



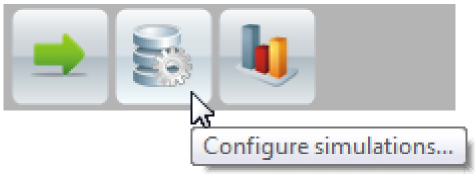
Because the optimal solar multiple depends on the LCOE, for accurate results, you should specify all of the project costs, financing, and incentive inputs in addition to the inputs specifying the physical characteristics of the solar field, power cycle and storage system before the optimization. However, for preliminary results, you can use default values for any variables for which you do not have values.

The following instructions describe the steps for optimizing the solar multiple for a preliminary system design that mostly uses default values except for a few key variables. This example is for a 50 MW system, but you can use the same procedure for a system of any size.

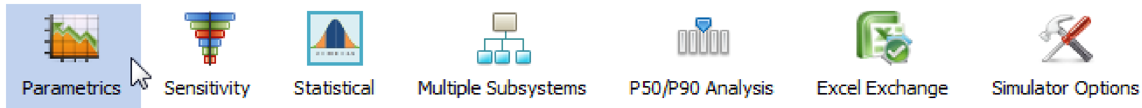
To optimize the solar field with no storage:

1. Create a new physical trough project with Utility IPP financing.
2. On the Location and Resource page, choose a location.
3. Follow the instructions above to find an appropriate irradiation at design value for your weather data. Use zero for both the collector tilt and azimuth variables.
4. On the Power Cycle page, for Design gross output, type 55 to specify a power block with a rated net electric output capacity of 50 MW (based on the default net conversion factor of 0.9).
5. On the Thermal Storage page, for **Full load hours of TES**, type 0 to specify a system with no storage.
6. On the Solar Field page, under **Solar Field Parameters**, choose **Option 1** (solar multiple) if it is not already active.

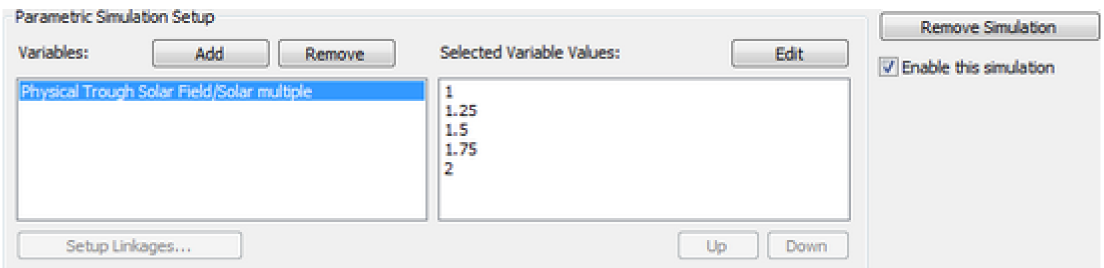
7. Click Configure simulations.



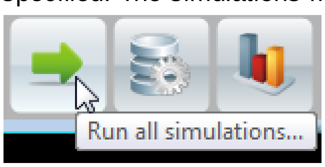
8. Click **Parametrics**.



9. Click **Add Parametric Simulation**.
10. Click **Add** to open the Choose Parametrics window.
11. In the Search box, type "solar multiple."
12. Check **Solar Multiple**.
13. Click **Edit** to open the Edit Parametric Values window.
14. Type the following values: Start Value = 1, End Value = 2, Increment = 0.25.
15. Click **Update**. The parametric simulation setup options should look like this:
16. Click **OK**.



17. Click Run all simulations. SAM will run a simulation for each of the 5 solar multiple values you specified. The simulations may take a few minutes to run.



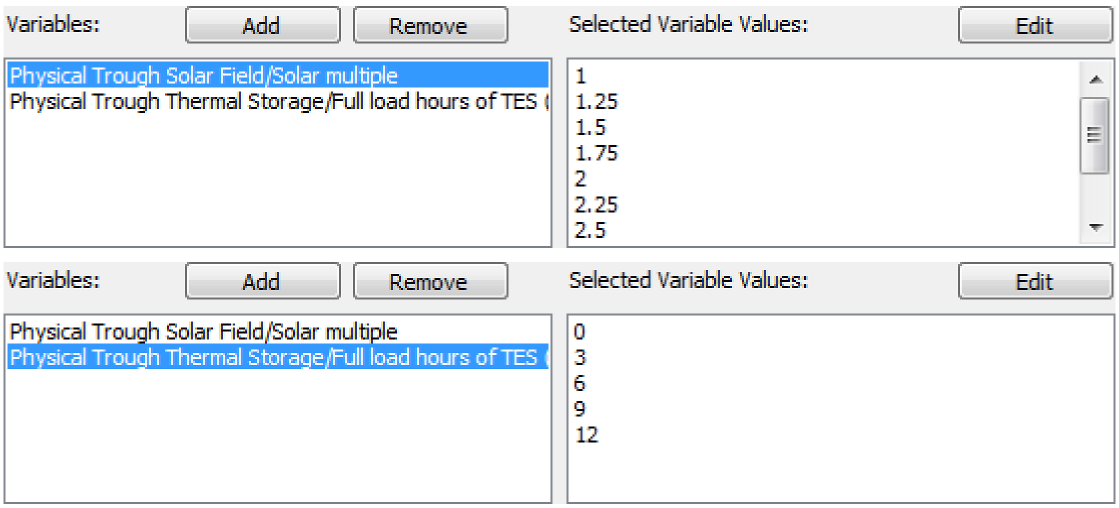
18. On the Results page, click **Add a new graph**.
19. Choose the following options: **Choose Simulation** = Parametric Set 1, **X Value** = {Solar Multiple}, **Y1 Values** = LCOE Nominal, **Graph Type** = Line Plot
20. Click **Accept**. SAM should display a graph that looks similar to the "Nominal LCOE vs Solar Multiple (No Storage)" graph above.
21. On the graph, find the solar multiple value that results in the lowest LCOE. If the minimum LCOE occurs at either end of the graph, you may need to add more values to the solar multiple parametric variable to find the optimal value.

Optimal Solar Multiple for a System with Storage

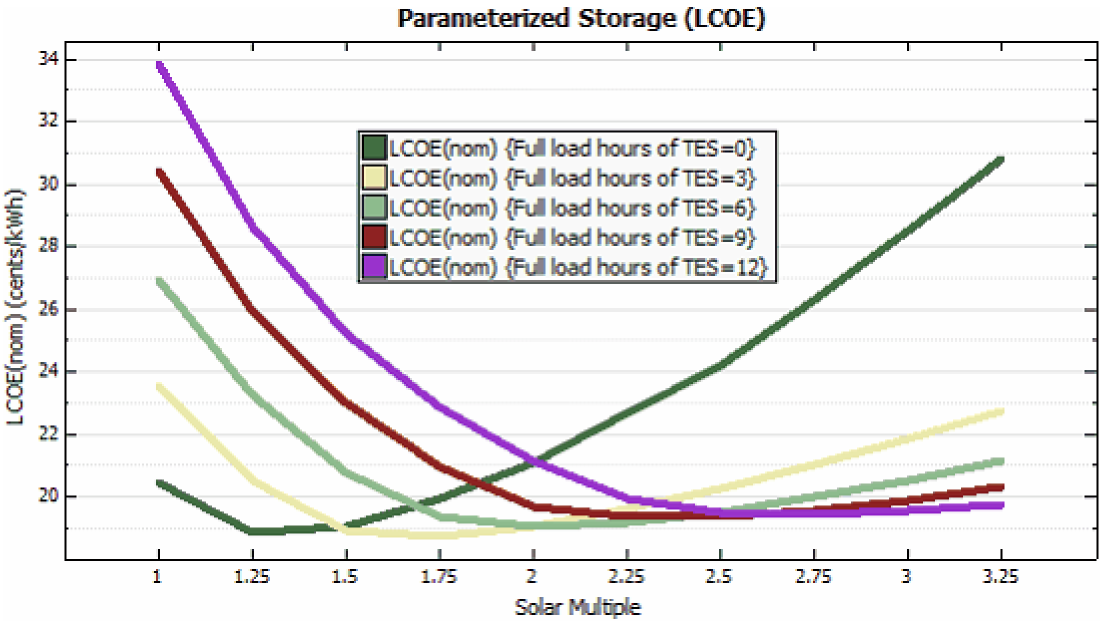
Note. The linear Fresnel model in the current version of SAM does not include a storage option.

Adding storage to the system introduces another level of complexity: Systems with storage can increase system output (and decrease the LCOE) by storing energy from an larger solar field for use during times when the solar field output is below the design point. However, the thermal energy storage system's cost and thermal losses also increase the LCOE.

To find the optimal combination of solar multiple and storage capacity for systems with thermal storage, run a parametric analysis as described above, but with two parametric variables instead of one: Solar multiple and Full load hours of TES (storage capacity). The parametric setup options should look similar to this:



After running simulations, you will be able to create a graph like the one below that allows you to choose the combination of solar multiple and storage capacity that minimizes the LCOE. For example, the following graph shows that for a system in Blythe, California, the optimal combination of solar multiple and thermal storage capacity is SM = 1.75 and Hours of TES = 3.



Each line in the graph represents a number of hours of thermal energy storage from the list we saw in the list of parametric values for the Equivalent Full Load Hours of TES variable: 0, 3, 6, 9, and 12 hours of storage.

For the no storage case (the dark green line, zero hours of storage), the lowest levelized cost of energy occurs at a solar multiple of 1.25. For a given storage capacity, as the solar multiple increases, both the area-dependent installation costs electricity output increase. The interaction of these factors causes the levelized cost of energy to decrease as the solar multiple increases from 1, but at some point the cost increase overwhelms the benefit of the increased electric energy output, and the levelized cost of energy begins to increase with the solar multiple.

Simplified Steps for Optimizing the Solar Field

If you are performing a preliminary analysis or learning to use SAM, you can use the following simplified steps, using default values for most of the inputs:

1. Choose a location on the Location and Resource page.
2. Specify the power cycle capacity on the Power Cycle page.
3. Choose an irradiation at design value on the Solar Field page.
4. Optimize the solar field aperture area using Option 1.

Overall Steps for Optimizing the Solar Field

1. Choose a location on the Location and Resource page.
2. Specify the power cycle capacity and other characteristics on the Power Cycle page.
3. Specify characteristics of the solar field components on the Receivers (HCEs) and Collectors (SCAs) pages.
4. If the system includes thermal energy storage, specify its characteristics on the Thermal Storage page. (Note. For systems with storage, use the optimization process in Step 8 below to find the optimal storage capacity.)

5. Define the project costs on the Trough System Costs page.
6. Configure a single loop and specify solar field heat transfer fluid (HTF) properties on the Solar Field page.
7. Specify the collector orientation on the Solar Field page.
8. Choose an irradiation at design value on the Solar Field page.
9. Either optimize the solar field aperture area using Option 1, or specify the solar field area explicitly using Option 2 on the Solar Field page.
10. Refine your analysis by adjusting other model parameters.

About the Heat Transfer Fluid Properties

The solar field heat transfer fluid (HTF) absorbs heat as it circulates through the heat collection elements in the solar field and transports the heat to the power block where it is used to run a turbine. Several types of heat transfer fluid are used for trough systems, including hydrocarbon (mineral) oils, synthetic oils, silicone oils and nitrate salts.

When you choose a heat transfer fluid, SAM populates the minimum HTF temperature variable with that oil's minimum operating temperature value. SAM will not allow the system to operate at a temperature below the minimum HTF temperature. Electric heaters in the system maintain the fluid temperature. SAM accounts for the electric power requirement for heating on the Parasitics page.

The remaining heat transfer fluid parameters describe characteristics of the solar field that affect the performance of the heat transfer fluid. The two area-related parameters refer to square meters of solar field area. If you are unsure of what values to use for these parameters, refer to the Solar Field page for the case in *Sample Parabolic Trough Systems.zsam*.

Note. Solar field outlet temperature and solar field area data for U.S. parabolic trough power plants are available on the Troughnet website at http://www.nrel.gov/csp/troughnet/power_plant_data.html.

If the heat transfer fluid you want to use in the solar field is not included in the Field HTF Fluid list, you can define a custom heat transfer fluid using the User-defined option in the list. To define a custom fluid, you need to know the following properties for at least two temperatures:

- Temperature, ºC
- Specific heat, kJ/kg-K
- Density, kg/m³
- Viscosity, Pa-s
- Kinematic viscosity, m²-s
- Conductivity, W/m-K
- Enthalpy, J/kg

To define a custom heat transfer fluid:

1. In the Field HTF fluid list, click **User-defined**.
2. In the Edit Material Properties table, change **Number of data points** to 2 or higher. The number should equal the number of temperature values for which you have data.
3. Type values for each property in the table.

   You can also import data from a text file of comma-separated values. Each row in the file should contain properties separated by commas, in the same the order that they appear in the Edit Material Properties window. Do not include a header row in the file.

Notes

Each row in the materials property fluid table must be for a set of properties at a specific temperature. No two rows should have the same temperature value.

SAM calculates property values from the table using linear interpolation.

The rows in the table must sorted by the temperature value, in either ascending or descending order.

The physical trough model uses the temperature, specific heat, density, viscosity, and conductivity values. It ignores the enthalpy and kinematic viscosity values (the empirical trough model does use those values).

For the physical trough model, if you specify user-defined HTF fluids with the same properties for the solar field and thermal storage system, on the Thermal Storage page, you should set both the **Hot side HX approach temp** and **Cold side HX approach temp** to zero to represent a system with no heat exchanger. (When the hot and cold side approach temperatures are zero, **Heat exchanger derate** is one.)

7.2.3 SCA / HCE

To view the SCA / HCE page, click **Solar Field** on the main window's navigation menu. Note that for the empirical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Empirical Trough System.

The SCA / HCE page displays the characteristics of the solar collector assembly (SCA) and heat collection elements (HCE) in the solar field. Note that the SCA is often referred to as the collector. The HCE is often referred to as the receiver.

A solar collector assembly (SCA) is an individually tracking component of the solar field that includes mirrors, a supporting structure, and heat collection elements or receivers.

A heat collection element (HCE) is a metal pipe contained in a vacuum within glass tube that runs through the focal line of the trough-shaped parabolic collector. Seals and bellows ensure that a vacuum is maintained in each tube. Anti-reflective coatings on the glass tube maximize the amount of solar radiation that enters the tube. Solar-selective radiation absorbing coatings on the metal tube maximize the transfer of energy from the solar radiation to the pipe.

Note. See http://www.nrel.gov/csp/troughnet/solar_field.html for more information on solar collector assemblies and heat collection elements. Also see relevant articles in the list of publications on the Troughnet website.

For a more detailed description of the model, please download the CSP trough reference manual from the SAM website's support page: https://sam.nrel.gov/reference.

Contents

Input Variable Reference

Solar Collector Assembly (SCA)

The solar collector assembly (SCA) input variables describe the dimensions and optical characteristics of the SCA or collector.

Current SCA inputs

The name of the collector in the SCA library

SCA Length (m)

The total length of a single SCA. Used in SCA end loss calculation.

SCA Aperture (m)

The structural width of a single SCA, including reflective area and gaps. Used in the row-to-row shadowing loss factor and HCE thermal loss calculations.

SCA Aperture Reflective Area (m^2)

The reflective area of a single SCA, not including gaps. Used in the solar field size calculations.

Average Focal Length (m)

Average trough focal length. Used in end gain and end loss factor calculations.

Incident Angle Modifier Coef F0, F1, F2

Incident angle modifier coefficients. Used to calculate the incident angle modifier factor, which is used to calculate the HCE absorbed energy and the solar field optical efficiency.

Tracking Error and Twist

Accounts for errors in the SCA's ability to track the sun. Sources of error may include poor alignment of sun sensor, tracking algorithm error, errors caused by the tracker drive update rate, and twisting of the SCA end at the sun sensor mounting location relative to the tracking unit end. A typical value is 0.985. Used to calculate SCA field error factor.

Geometric Accuracy

Accounts for SCA optical errors caused by misaligned mirrors, mirror contour distortion caused by the support structure, mirror shape errors compared to an ideal parabola, and misaligned or distorted HCE. A typical range of values is between 0.97 and 0.98. Used to calculate SCA field error factor.

Mirror Reflectance

The mirror reflectance input is the solar weighted specular reflectance. The solar-weighted specular reflectance is the fraction of incident solar radiation reflected into a given solid angle about the specular reflection direction. The appropriate choice for the solid angle is that subtended by the receiver as viewed from the point on the mirror surface from which the ray is being reflected. For parabolic troughs, typical values for solar mirrors are 0.923 (4-mm glass), 0.945 (1-mm or laminated glass), 0..906 (silvered polymer), 0.836 (enhanced anodized aluminum), and 0.957 (silvered front surface).

Mirror Cleanliness Factor (avg)

Accounts for dirt and dust on the mirrors that reduce their effective reflectivity. Typically, mirrors are continuously cleaned, but a single mirror may be cleaned once each one or two weeks. The expected overall effect on the total solar field would be an average loss of between one and two percent. A typical value would be 0.985. Used to calculate SCA field error factor.

Dust on Envelope (avg)

Accounts for dust on the HCE envelope that affects light transmission. A typical value would be 0.99. Used to calculate HCE heat loss.

Concentrator Factor

A additional error factor to make it possible to adjust the SCE performance without modifying the other error factors. Useful for modeling an improved or degraded SCE. The default value is 1. Used to calculate SCA field error factor.

Solar Field Availability

Accounts for solar field down time for maintenance and repairs. Used to calculate absorbed energy.

Heat Collection Element (HCE)

The HCE variables describe the properties of up to four HCE types that can make up the solar field. This makes it possible to model a solar field with HCEs in different states. Each set of properties applies to one of the HCE types. The Fraction of Field variable determines what portion of the solar field is made up of a given HCE type.

Current HCE inputs

The name of the receiver and its condition. Vacuum refers to an HCE in good condition, lost vacuum, broken glass, and hydrogen refer to different problem conditions. You can define up to four HCE (receiver) conditions.

Fraction of Field

Fraction of solar field using this HCE type and condition. Used to calculate HCE field error factor and HCE heat loss.

Bellows Shadowing

The portion of the HCE tube that does not absorb solar thermal radiation. Used to calculate HCE field error factor.

Envelope Transmissivity

Used to calculate HCE field error factor.

Absorber Absorption

Accounts for inefficiencies in the HCE black coating. Used to calculate HCE field error factor.

Unaccounted

Allows for adjustment of the HCE performance to explore effect of changes in performance of the HCE without changing the values of other correction factors. A typical value is 1. Used to calculate HCE field error factor.

Optical Efficiency (HCE)

The design optical efficiency of each of the four receiver type and condition options. SAM uses the values to calculate the design weighted optical efficiency.

Optical Efficiency = SCA Field Error × Dust on Envelope × Bellows Shadowing × Envelope Transmissivity × Absorber Absorption × Unaccounted

SCA Field Error = Tracking Error and Twist × Geometric Accuracy × Mirror Reflectivity × Mirror Cleanliness Factor × Concentrator Factor

Optical Efficiency (Weighted)

The design weighted optical efficiency, representing the average optical efficiency of all receivers in the field. SAM uses the value to calculate the solar field area. Note that SAM also calculates a separate HCE optical efficiency value for each hour during simulation that counts for the loss factors on the SCA / HCE page that also accounts for the incident angle modifier factor, which depends on the time of day and collector orientation.

Optical Efficiency Weighted = Optical Efficiency 1 × Percent of Solar Field 1 + Optical Efficiency 2 × Percent of Solar Field 2 + Optical Efficiency 3 × Percent of Solar Field 3 + Optical Efficiency 4 × Percent of Solar Field 4

Heat Loss Coefficient A0...A6

Used to calculate the HCE heat loss. The default values are based on NREL modeling and test results. (See Forristall R, 2003. Heat Transfer Analysis and Modeling of a Parabolic Trough Solar Receiver Implemented in Engineering Equation Solver. National Renewable Energy Laboratory NREL/TP-550-34169. http://www.nrel.gov/csp/troughnet/pdfs/34169.pdf., and Burkholder F et al, 2009, Heat Loss Testing of Schott's 2008 PTR70 Parabolic Trough Receiver. National Renewable Energy Laboratory NREL/TP-550-45633. http://www.nrel.gov/csp/troughnet/pdfs/45633.pdf)

Heat Loss Factor

The design heat loss factor that applies to the active HCE type and condition. Used to calculate design HCE heat loss that is part of the solar field area equation. The heat loss factor scales the heat loss equation and can be used to fine tune the results when measured heat loss data are available. The default value of 1.0 is valid for the current version of SAM using the default heat loss coefficients.

Min windspeed (m/s)

Used to calculate the HCE heat loss for hours when the wind speed from the weather file is lower than the minimum wind speed.

The following heat loss values are provided for reference. SAM calculates the HCE heat loss for each hour during simulation based on the loss factor coefficients on the SCA / HCE page and other values from the weather data.

HCE Heat Losses (W/m)

$$Q_{\mathrm{HCEHLD,n}} = \left(Q_{\mathrm{HCEHLD1,n}} + Q_{\mathrm{HCEHLD2,n}} + Q_{\mathrm{HCEHLD3,n}} + Q_{\mathrm{HCEHLD4,n}}\right) \cdot F_{\mathrm{HeatLoss,n}}$$

$$Q_{\mathrm{HCEHLD1,n}} = F_{\mathrm{HLA0}} + F_{\mathrm{HLA5}} \cdot \sqrt{v_{\mathrm{WindRef}}}$$

$$Q_{\mathrm{HCEHLD2,n}} = \left(F_{\mathrm{HLA1}} + F_{\mathrm{HLA6}} \cdot \sqrt{v_{\mathrm{WindRef}}}\right) \cdot \frac{T_{\mathrm{SFOutD}} + T_{\mathrm{SFInD}} - T_{\mathrm{AmbientRef}}}{2}$$

$$Q_{\mathrm{HCEHLD3,n}} = \left(F_{\mathrm{HLA2}} + F_{\mathrm{HLA4}} \cdot Q_{\mathrm{DNIRef}}\right) \cdot \frac{T_{\mathrm{SFOutD}}{}^2 + T_{\mathrm{SFOutD}} \cdot T_{\mathrm{SFInD}} + T_{\mathrm{SFInD}}{}^2}{3}$$

$$Q_{\mathrm{HCEHLD4,n}} = F_{\mathrm{HLA3}} \cdot \frac{\left(T_{\mathrm{SFOutD}}{}^2 + T_{\mathrm{SFInD}}{}^2\right) \cdot \left(T_{\mathrm{SFOutD}} + T_{\mathrm{SFInD}}\right)}{4}$$

Where,

$Q_{HCEHLD,n}$ (W/m)	HCE heat losses for HCE type *n* expressed in thermal Watts per meter
$F_{HeatLoss,n}$	Heat Loss Factor for HCE type *n*
$F_{A0} \ldots F_{A6}$	A0 Heat Loss Coefficient through A6 Heat Loss Coefficient
T_{SFin} (°C)	Solar Field Inlet Temperature from the Solar Field page
T_{SFout} (°C)	Solar Field Outlet Temperature from the Solar Field page
T_{Amb} (°C)	Reference ambient temperature from the Solar Field page
Q_{DNIRef}	Reference direct normal radiation from the Solar Field page
n_{Wind} (m/s)	Reference wind velocity from the Solar Field page

Thermal Losses (Weighted W/m)

Thermal Losses Weighted W/m = HCE Heat Losses 1 × Percent of Solar Field 1 + HCE Heat Losses 2 × Percent of Solar Field 2 + HCE Heat Losses 3 × Percent of Solar Field 3 + HCE Heat Losses 4 × Percent of Solar Field 4

Thermal Losses (Weighted W/m2)

Thermal Losses Weighted W/m2 = Thermal Losses Weighted W/m ÷ SCA Aperture

About the SCA Parameters

The default SCA library includes a set of parameters for four types of SCAs described in the table below. These SCA types are either installed in currently operating systems, or were used in past system designs. See Working with Libraries for information about managing libraries.

Table 8. Default collector types.

Name	Description	Location
Euro Trough ET150	Torque box, galvanized steel	SEGS V, Kramer Junction, California
Luz LS-2	Torque-tube, galvanized steel	SEGS I - VII, Kramer Junction, California
Luz LS-3	Bridge truss, galvanized steel	SEGS VII - IX, Kramer Junction, California

Solargenix SGX-1	Organic hubbing structure, extruded aluminum	Nevada Solar One, Boulder City, Nevada

The values of input variables on the SCA / HCE page are stored in libraries. See Working with Libraries for information about managing libraries.

About the HCE Parameters

The HCE library includes four HCE types, and for each HCE type, five HCE conditions. See Working with Libraries for information about managing libraries.

For each HCE type and condition, you can assign a Percent of Field value. For example, in the figure below, the receiver type is Schott PTR70, and 98.5% percent of the HCEs are in normal condition, 1.0% have lost vacuum, 0.5% have glass damage, and 0% have allowed hydrogen to enter the tube.

When you select a name from the Receiver Type and Condition list, SAM populates the optical and heat loss parameters using values stored in the library. When you change one or more of these values, SAM creates a copy of the parameter set and adds it to the library under the name "CUSTOM CUSTOM."

The four HCE types are described in the table below.

Table 9. Default HCE types.

HCE Type	Description
Luz Cermet	Original HCE design. Low reliability of seals.
Schott PTR70 Vacuum	Newer design with improved reliability. Two versions are available.
Solel UVAC2	Newer design with improved reliability.
Solel UVAC3	The newest HCE available as of May 2008.

The performance of the HCE is highly dependent on the quality of the vacuum in the glass tube. SAM models the HCE under the five conditions described in the following table.

Table 10. HCE conditions.

HCE Condition	Description
Broken glass	Glass tube is damaged, increasing heat transfer between tube and atmosphere.
Fluorescent	Selective coating on metal tube is compromised, reducing absorption of solar radiation
Hydrogen	Hydrogen from hydrocarbon-based heat transfer fluid (e.g., mineral oil) has permeated through metal tube into the vacuum, increasing heat transfer between metal tube and glass.
Lost vacuum	Glass-to-metal seal is compromised
Vacuum	HCE is not damaged and is operating as designed.

7.2.4 Power Block

To view the Power Block page, click **Power Block** on the main window's navigation menu. Note that for the empirical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Empirical Trough System.

The Power Block parameters describe the equipment in the system that converts thermal energy from the solar field or thermal energy storage system into electricity. The power block is based on a steam turbine that runs on a conventional Rankine power cycle and may or may not include fossil fuel backup. Power block components include a turbine, heat exchangers to transfer heat from the solar field or thermal energy storage system to the turbine, and a cooling system to dissipate waste heat. SAM considers the thermal energy storage system to be a separate component, which is described on the Thermal Storage page.

The input variables on the Power Block page are divided into two groups. The turbine ratings group determines the capacity of the power block, and the power cycle group defines the performance parameters of the reference turbine.

For a more detailed description of the model, please download the CSP trough reference manual from the SAM website's support page: https://sam.nrel.gov/reference.

Contents

Input Variable Reference

Plant Characteristics

Design Gross Output (MWe)

The power cycle's design output, not accounting for parasitic losses. SAM uses this value to size system components, such as the solar field area when you use the solar multiple to specify the solar field size.

Estimated Gross to Net Conversion Factor

An estimate of the ratio of the electric energy delivered to the grid to the power cycle's gross output. SAM uses the factor to calculate the system's nameplate capacity for capacity-related calculations, including the estimated total cost per net capacity value on the System Costs page, capacity-based incentives on the Incentives page, and the capacity factor reported in the results.

Estimated Net Output at Design (MWe)

The power cycle's nominal capacity, calculated as the product of the design gross output and estimated gross to net conversion factor. SAM uses this value to calculate the system's rated capacity for capacity-related calculations, including the estimated total cost per net capacity value on the System Costs page, capacity-based incentives on the Incentives page, and the capacity factor reported in the results.

Power Cycle

The variables in the power cycle group describe a reference steam turbine. SAM uses the reference turbine specifications to calculate the turbine output, and then scales the actual output based on the turbine rating variables. Each set of reference turbine specifications is stored in the reference turbine library.

Current Power Block

Name of the reference turbine. Selecting a reference system determines the values of the other power cycle variables.

Design Cycle Thermal Input (MWt)

The thermal energy required as input to the power block to generate the design turbine gross (electric) output. SAM uses the design turbine thermal input to calculate several power block capacity-related values, including the solar field size, power block design point gross output, and parasitic losses.

Design Cycle Thermal Input = Design Turbine Gross Output ÷ Rated Cycle Conversion Efficiency

Rated Cycle Conversion Efficiency

Total thermal to electric efficiency of the reference turbine. Used to calculate the design turbine thermal input.

Max Turbine Over Design Operation

The turbine's maximum output expressed as a fraction of the design turbine thermal input. Used by the dispatch module to set the power block thermal input limits.

Min Turbine Operation

The turbine's minimum load expressed as a fraction of the design turbine thermal input. Used by the dispatch module to set the power block thermal input limits.

Frac of Thermal Power for Startup

Fraction of the design turbine thermal input required to bring the system to operating temperature after a period of non-operation. Used by the dispatch module to calculate the required start-up energy.

Boiler LHV Efficiency

The back-up boiler's lower heating value efficiency. Used by the power block module to calculate the quantity of gas required by the back-up boiler.

Max Thermal Input (MWt)

The maximum thermal energy that can be delivered to the power block by the solar field, thermal energy storage system or both.

Max Thermal Input = Design Cycle Thermal Input × (F4 × Max Turbine Over Design Operation^4 + F3 × Max Turbine Over Design Operation^3 + F2 × Max Turbine Over Design Operation^2 + F1 × Max Turbine Over Design Operation + F0)

Where F0-4 are the Cycle Part-load Elec to Therm factors that you specify.

Min Thermal Input (MWt)

The minimum thermal energy that can be delivered to the power block by the solar field, thermal energy storage system or both.

Max Thermal Input = Design Cycle Thermal Input × (F4 × Min Turbine Operation^4 + F3 × Max Turbine Over Design Operation^3 + F2 × Min Turbine Operation^2 + F1 × Min Turbine Operation + F0)

Where F0-4 are the Cycle Part-load Elec to Therm factors that you specify.

Cycle Part-load Therm to Elec

Factors for the turbine thermal-to-electric efficiency polynomial equation. Used to calculate the design point gross output, which is the portion of the power block's electric output converted from solar energy before losses. See Power Block Simulation Calculations for details.

Cycle Part-load Elec to Therm

Factors for turbine's part load electric-to-thermal efficiency polynomial equation. Used to calculate the energy in kilowatt-hours of natural gas equivalent required by the backup boiler. SAM dispatches the backup boiler based on the fossil-fill fraction table in the thermal storage dispatch parameters on the Thermal Storage page.

Cooling Tower Correction

Cooling tower correction factor. Used to calculate the temperature correction factor that represents cooling tower losses. To model a system with no cooling tower, set F0 to 1, and F1 = F2 = F3 = F4 =0.

Temperature Correction Mode

In the dry bulb mode, SAM calculates a temperature correction factor to account for cooling tower losses based on the ambient temperature from the weather data set. In wet bulb mode, SAM calculates the wet bulb temperature from the ambient temperature and relative humidity from the weather data.

Power Cycle Library Options

The power cycle library includes six reference turbines. See Working with Libraries for information about managing libraries.

The reference turbines include five conventional Rankine-cycle steam turbines in a range of sizes, and one organic Rankine-cycle turbine. Conventional Rankine-cycle turbines are similar to those used in coal, nuclear, or natural gas power plants. A heat exchanger transfers energy from the solar field's heat transfer fluid to generate steam that drives the turbine. The organic Rankine-cycle turbine operates on the same principle as the conventional turbine, but uses an organic fluid, typically butane or pentane, to run the turbine instead of water.

Table 11. Power cycle reference systems.

Reference System	Approximate Solar Field Size Range m^2	Approximate Operating Temperature °C	Suggested Modeling Application
APS Ormat 1 MWe 300C	10,000	300	Organic Rankine-cycle power block
Nexant 450C HTF	-	450	High-temperature heat transfer fluid (molten salt)
Nexant 500C HTF	-	500	High-temperature heat transfer fluid (molten salt)
SEGS 30 MWe Turbine	180,000 - 230,000	300 - 400	Typical applications
SEGS 80 MWe Turbine	460,000 - 480,000	400	Typical applications

Siemens 400C HTF		400	High-temperature heat transfer fluid

When you choose a turbine from the reference system library, SAM changes the values of the Power Cycle variables. The following table shows the power cycle parameters for the standard reference systems. Note that you can use any value for the Rated Turbine Net Capacity and Design Turbine Gross Output variables, SAM will use the reference system parameters with the rated and design turbine parameters.

Table 12. Reference system parameters.

Parameter Name	SEGS 30	SEGS 80	APS ORC	Nexant 450	Nexant 500	Siemens 400
Estimated Net Output at Design	30	80	1	100	100	50
Design Gross Output	35	89	1.160	110	110	55
Design Cycle Thermal Input	93.3	235.8	5.600	278.0	269.9	147.2
Rated Cycle Conversion Efficiency	0.3749	0.3774	0.2071	0.3957	0.4076	0.3736
Max Turbine Over Design Operation	1.15	1.15	1.15	1.15	1.15	1.15
Min Turbine Operation	0.15	0.15	0.15	0.15	0.15	0.15
Cycle Part-load Therm to Elec F0	-0.0571910	-0.0377260	-0.1593790	-0.0240590	-0.0252994	-0.0298
Cycle Part-load Therm to Elec F1	1.0041000	1.0062000	0.9261810	1.0254800	1.0261900	0.7219
Cycle Part-load Therm to Elec F2	0.1255000	0.0763160	1.1349230	0.0000000	0.0000000	0.7158
Cycle Part-load Therm to Elec F3	-0.0724470	-0.0447750	-1.3605660	0.0000000	0.0000000	-0.5518
Cycle Part-load Therm to Elec F4	0.0000000	0.0000000	0.4588420	0.0000000	0.0000000	0.1430
Cycle Part-load Elec to Therm F0	0.0565200	0.0373700	0.1492050	0.0234837	0.0246620	0.044964
Cycle Part-load Elec to Therm F1	0.9822000	0.9882300	0.8521820	0.9751230	0.9744650	1.182900
Cycle Part-load Elec to Therm F2	-0.0982950	-0.0649910	-0.3247150	0.0000000	0.0000000	-0.563880
Cycle Part-load Elec to Therm F3	0.0595730	0.0393880	0.4486300	0.0000000	0.0000000	0.467190
Cycle Part-load Elec to Therm F4	0.0000000	0.0000000	-0.1256020	0.0000000	0.0000000	-0.130090

You can use any of the built-in power cycle options to model most systems expected to run at or near the power block's design point for most operating hours. You can specify your own power cycle if you have a set of part load coefficients from the manufacturer, or if you have calculated coefficients using power plant simulation or equation solving software. The part load equation is a fourth-order or lower polynomial equation that describes the relationship between power cycle efficiency and operating load.

Power Block Simulation Calculations

The equations below show how SAM uses the Power Cycle parameters during simulations to calculate the thermal energy delivered to the power block, Q_{pb}. You can use this information to develop your own set of coefficients instead of coefficients from the power cycle library.

$$\overline{\dot{Q}_{pb}} = \frac{\dot{Q}_{pb}}{\dot{Q}_{design}}$$

This is the non-dimensional thermal energy into the power block. This fractional value is input into the **Cycle Part-load Therm to Elec** polynomial equation that describes non-dimensional net electric output as a function of load:

$$\overline{\dot{W}_{gr}} = F_0 + F_1 \cdot \overline{\dot{Q}_{pb}} + F_2 \cdot \overline{\dot{Q}_{pb}}^2 + F_3 \cdot \overline{\dot{Q}_{pb}}^3 + F_4 \cdot \overline{\dot{Q}_{pb}}^4$$

This non-dimensional gross cycle output is multiplied by the design-point gross cycle output to get the preliminary dimensional gross power output:

$$\dot{W}_{gr} = \dot{W}_{gr} \cdot \dot{W}_{gr,design}$$

The gross power output is also adjusted by the ambient temperature using the **Cooling Tower Correction** polynomial. It generally follows the same form as the polynomial for load shown above, except the non-dimensional load term (Q_{pb}) is replaced by the actual wet or dry-bulb temperature in units of °C. The temperature adjustment factor is calculated as follows:

$$X_T = F_{T0} + F_{T1} \cdot T_{amb} + F_{T2} \cdot T_{amb}^2 + F_{T3} \cdot T_{amb}^3 + F_{T4} \cdot T_{amb}^4$$

The gross power cycle output is then multiplied by the temperature correction factor to increase or decrease the total power cycle productivity.

$$\dot{W}_{gr} = \dot{W}_{gr} \cdot X_T$$

The **Cycle Part-load Elec to Therm** polynomial equation is used to determine the performance and fuel consumption of the fossil backup system. Note that this relationship is only used when the fossil backup system is running and is not part of the normal solar-to-electric conversion process. The formula for obtaining heat input from a fossil backup using the polynomial coefficients depends on whether the fossil backup in combination with thermal storage and energy from the solar field can meet the design-point thermal input of the power cycle. If the total thermal input including fossil backup meets the thermal load requirement for the power cycle, the fuel usage is calculated at the design-point as follows:

$$\dot{Q}_{gas} = X_{fossil} \cdot \frac{\dot{Q}_{pb,design}}{\dot{W}_{pb,design} \cdot \eta_{LHV}}$$

The fraction of the thermal load that is supplied by fossil energy is indicated as X_{fossil} in this equation, and the lower-heating-value efficiency of the fossil source is η_{LHV}. In cases where the total thermal input to the power cycle falls short of the amount required to power the cycle at full load, a polynomial equation with user-defined coefficients is used to calculate the conversion efficiency.

$$\dot{Q}_{gas} = \left[\dot{Q}_{pb,design} \cdot \left(F_{f0} + F_{f1} \cdot \overline{\dot{Q}_{pb}} + F_{f2} \cdot \overline{\dot{Q}_{pb}}^2 + F_{f3} \cdot \overline{\dot{Q}_{pb}}^3 + F_{f4} \cdot \overline{\dot{Q}_{pb}}^4\right) - \left(\dot{Q}_{sf} + \dot{Q}_{TES}\right)\right] \cdot \frac{1}{\eta_{LHV}}$$

In this case, the total non-dimensional energy to the power cycle Q_{pb} is equal to the sum of the contributions from thermal storage, the solar field, and the fossil backup. Consequently, the non-fossil contributions are subtracted after the polynomial result has been applied. The total fuel consumption is calculated by converting from thermal energy to fuel usage with the lower-heating-value efficiency.

7.2.5 Thermal Storage

To view the Thermal Storage page, click **Thermal Storage** on the main window's navigation menu. Note that for the empirical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Empirical Trough System.

A thermal energy storage system (TES) stores heat from the solar field in a liquid medium. Heat from the storage system can drive the power block turbine during periods of low or no sunlight. A TES is beneficial in many places where the peak demand for power occurs after the sun has set. Adding TES to a parabolic trough system allows the collection of solar energy to be separated from the operation of the power block. For example, a system might be able to collect energy in the morning and use it to generate electricity late into the evening.

In direct systems, the heat transfer fluid itself serves as the storage medium. In indirect systems, a separate fluid is the storage medium, and heat is transferred from the HTF to the storage medium through heat exchangers. The TES system two tanks, pumps to circulate the liquids, and depending on the design, heat exchangers. The two-tank system consists of a hot tank to store heat from the solar field, and a cold tank to store the cooled storage medium after the power block has extracted its energy.

Note. For more information on thermal energy storage systems for parabolic trough systems, see http://www.nrel.gov/csp/troughnet/thermal_energy_storage.html.

The user inputs on the Thermal Storage page are divided into two groups. The thermal energy storage (TES) group defines the thermal energy storage capacity and type along with some efficiency parameters. The thermal storage dispatch controls group variables determine the operation of the storage and fossil back up systems.

For a more detailed description of the model, please download the CSP trough reference manual from the SAM website's support page: https://sam.nrel.gov/reference.

Contents

- Input Variable Reference describes the input variables and options on the Thermal Storage page.
- Storage and Fossil Backup Dispatch Controls describes the dispatch controls that determine the timing of energy releases from the storage and fossil back up systems, and explains how to assign dispatch periods to weekday and weekend schedules.

Input Variable Reference

Thermal Energy Storage (TES)

Equiv Full Load Hours of TES hours (hours)

The thermal storage capacity expressed in number of hours of thermal energy delivered at the power block's design thermal input level. The physical capacity is the number of hours of storage multiplied by the power block design thermal input. Used to calculate the TES maximum storage capacity.

Storage System Configuration

The current version of SAM models a two-tank TES consisting of a cold storage tank and hot storage tank.

Storage Fluid Type

The Storage fluid used in the TES. When the storage fluid and solar field heat transfer fluid (HTF) are different, the system is an indirect system with a heat exchanger. When the storage fluid and solar field HTF are the same, the system is a direct system that uses the solar field HTF as the storage medium. Used to calculate the heat exchanger duty. See the Solar Field page for a table of fluid properties.

Turbine TES Adj Efficiency

SAM applies the TES efficiency adjustment factor to the turbine efficiency for trough systems with storage to account for the lower steam temperature that results from imperfect heat exchange in the storage system. Used to calculate maximum TES discharge rate. Also used to calculate a TES correction factor.

Turbine TES Adj Gross Output

Efficiency adjustment factor. Used to calculate maximum TES discharge rate.

Initial Thermal Storage (MWht)

The amount of energy in storage when the simulation starts, at midnight on January 1. The default value is zero.

Tank Heat Losses (MWht)

Storage tank thermal losses. SAM subtracts value from the total energy in storage at the end of each simulation hour. See the table below for suggested values.

An increase in the hours of thermal storage requires a both an increase in the solar field size to minimize the levelized cost of energy for the system, and an increase in the tank heat losses to account for the larger tank. See Sizing the Solar Field for a discussion of an approach to optimize the solar field for system with storage.

The following table shows suggested tank heat loss values for three sample systems over a range of thermal storage capacities. The relationship between tank heat losses and hours of thermal storage is linear, so you can extrapolate to estimate values for storage capacity values not on the table.

System Description	Hours of Thermal Storage					
	0	3	6	9	12	15
100 MW Two Tank Indirect VP-1/Nitrate Salt	0	0.62	0.96	1.23	1.56	1.87
200 MW Two Tank Indirect VP-1/Nitrate Salt	0	1.0	1.61	2.21	2.81	3.56
200 MW Two Tank Direct Hitec Salt	0	0.34	0.64	0.93	1.24	1.52

Maximum Energy Storage (MWht)

The maximum thermal energy storage capacity of the TES.

Maximum Energy Storage = Equiv. Full Load Hours of TES × Design Turbine Thermal Input

Design Turbine Thermal Input (MWt)

The thermal input requirement of the power block to operate at its design point. Used to calculate the following dispatch parameters: power block input limits, power block load requirement, TES maximum storage capacity, and the start-up requirement

Max Power to Storage (MWt)

Maximum TES charge rate. Used in the dispatch calculation when energy from the solar field exceeds the power block load requirement.

When Storage Fluid Type is different from Solar Field HTF Type on the Solar Field page, SAM assumes that the TES includes a heat exchanger, and Heat Exchanger Duty > 1:

Max Power to Storage = Heat Exchanger Duty × Design Turbine Thermal Input

When the TES and Solar Field fluids are the same, SAM assumes there is no heat exchanger, and Heat Exchanger Duty = 1:

Max Power to Storage = Solar Multiple Calc × Max Turbine Over Design Operation × Design Turbine Thermal Input

Where Design Turbine Thermal Input is the Design Cycle Thermal Input value from the Power Block page, Max Turbine Over Design Operation is from the Power Block page, and Solar Multiple Calc is from the Solar Field page.

Max Power From Storage (MWt)

Maximum TES discharge rate. Used in the dispatch calculation when energy from the solar field is less or equal to than the power block load requirement.

When Storage Fluid Type is different from Solar Field HTF Type on the Solar Field page, SAM assumes that the TES includes a heat exchanger, and Heat Exchanger Duty > 1:

Max Power From Storage = Maximum Power to Storage × (Turbine TES Adj Gross Output ÷ Turbine TES Adj Efficiency)

When the TES and Solar Field fluids are the same, SAM assumes there is no heat exchanger, and Heat Exchanger Duty = 1:

Max Power From Storage = Design Turbine Thermal Input × Max Turbine Over Design Operation × (Turbine TES Adj Gross Output ÷ Turbine TES Adj Efficiency)

Where Design Turbine Thermal Input is the Design Cycle Thermal Input value from the Power Block page, Max Turbine Over Design Operation is from the Power Block page.

Heat Exchanger Duty

Applies only to indirect thermal storage systems that use a different storage fluid and solar field HTF. Used to calculate the maximum TES charge rate.

When the solar multiple is greater than one:

Heat Exchanger Duty = Solar Multiple Calc - 1

When the solar multiple is equal to or less than one:

Heat Exchanger Duty = 0

Where Solar Multiple Calc is from the Solar Field page.

Thermal Storage Dispatch Control

The thermal storage dispatch control variables determine how energy is dispatched from the TES, what load level the power block and optional backup boiler operate, and the times that the optional PPA power price multipliers apply.

Current Dispatch Schedule

The name of the dispatch schedule displayed in the Weekday and Weekend schedule matrices.

Dispatch Schedule Library

Click to choose a dispatch schedule from the library. See Storage and Fossil Dispatch Controls for details.

The storage dispatch control variables each have six values, one for each of six possible dispatch periods. They determine how SAM calculates the energy flows between the solar field, thermal energy storage system, and power block. The fossil-fill fraction is used to calculate the energy from a backup boiler.

Storage Dispatch Fraction with Solar

The fraction of the TES maximum storage capacity indicating the minimum level of charge that the storage system can discharge to while the solar field is producing power. A value of zero will always dispatch the TES in any hour assigned to the given dispatch period; a value of one will never dispatch the TES. Used to calculate the storage dispatch levels.

Storage Dispatch Fraction without Solar

The fraction of the TES maximum storage capacity indicating the minimum level of charge that the storage system can discharge to while no solar resource is available. A value of zero will always dispatch the TES in any hour assigned to the given dispatch period; a value of one will never dispatch the TES. Used to calculate the storage dispatch levels.

Turbine Output Fraction

The fraction of design-point thermal load to the power block before part-load and temperature efficiency corrections. These values allow the user to dispatch the power cycle at a desired level according to the time-of-dispatch period.

Fossil Fill Fraction

A fraction of the power block design turbine gross output from the Power Block page that can be met by the backup boiler. Used by the power block module to calculate the energy from the backup boiler.

TOD Factor

The time-of-delivery (TOD) factors allow you to specify a set of TOD power price factors to model time-dependent pricing for projects with one of the Utility Financing options.

The TOD factors are a set of multipliers that SAM uses to adjust the PPA price based on time of day and month of year for utility projects. The TOD factors work in conjunction with the assumptions on the Financing page.

Note. For utility projects with no TOD factors, set the value for all periods to one.

For the CSP models, although the TOD power price factors are financial model inputs, they are on the Storage page because it includes other time-dependent variables, and there may be a relationship between the dispatch factors and the TOD power price factors. For PV and other technology models, the TOD power price factors are on a separate Time of Delivery Factors input page. For a description of how to specify the TOD power price factors for all technology models, see Time of Delivery Factors.

For a description of TOD-related simulation results, see PPA Revenue with TOD Factors.

Storage and Fossil Dispatch Controls

The thermal storage dispatch controls determine the timing of releases of energy from the thermal energy storage and fossil backup systems to the power block. When the system includes thermal energy storage or fossil backup, SAM can use a different dispatch strategy for up to six different dispatch periods.

Storage Dispatch

SAM decides whether or not to operate the power block in each hour of the simulation based on how much energy is stored in the TES, how much energy is provided by the solar field, and the values of the thermal storage dispatch controls parameters. You can define when the power block operates for each of the six dispatch periods. For each hour in the simulation, if the power block is not already operating, SAM looks at the amount of energy that is in thermal energy storage at the beginning of the hour and decides whether it should operate the power block. For each period, there are two targets for starting the power block: one for periods of sunshine (w/solar), and one for period of no sunshine (w/o solar).

The turbine output fraction for each dispatch period determines at what load level the power block runs using energy from storage during that period. The load level is a function of the turbine output fraction, design turbine thermal input, and the five turbine part load electric to thermal factors on the Power Block page.

For each dispatch period during periods of sunshine, thermal storage is dispatched to meet the power block load level for that period only when the thermal power from the solar field is insufficient and available storage is equal to or greater than the product of the storage dispatch fraction (with solar) and maximum energy in storage. Similarly, during periods of no sunshine when no thermal power is produced by the solar field, the power block will not run except when the energy available in storage is equal to or greater than the product of storage dispatch fraction (without solar) and maximum energy in storage.

By setting the thermal storage dispatch controls parameters, you can simulate the effect of a clear day when the operator may need to start the plant earlier in the day to make sure that the storage is not filled to capacity and solar energy is dumped, or of a cloudy day when the operator may want to store energy for later use in a higher value period.

Fossil Dispatch

When the fossil fill fraction is greater than zero for any dispatch period, the system is considered to include fossil backup. The fossil fill fraction defines the solar output level at which the backup system runs during each hour of a specific dispatch period. For example, a fossil fill fraction of 1.0 would require that the fossil backup operate to fill in every hour during a specified period to 100% of design output. In that case, during periods when solar is providing 100% output, no fossil energy would be used. When solar is providing less than 100% output, the fossil backup operates to fill in the remaining energy so that the system achieves 100% output. For a fossil fill fraction of 0.5, the system would use energy from the fossil backup only when solar output drops below 50%.

The boiler LHV efficiency value on the Power Block page determines the quantity of fuel used by the fossil backup system. A value of 0.9 is reasonable for a natural gas-fired backup boiler. SAM includes the cost of fuel for the backup system in the levelized cost of energy and other metrics reported in the results, and reports the energy equivalent of the hourly fuel consumption in the time series simulation results. The cost of fuel for the backup system is defined on the Trough System Costs page.

TOD Factor

The time-of-delivery (TOD) factors allow you to specify a set of TOD power price factors to model time-dependent pricing for projects with one of the Utility Financing options.

The TOD factors are a set of multipliers that SAM uses to adjust the PPA price based on time of day and month of year for utility projects. The TOD factors work in conjunction with the assumptions on the Financing page.

Note. For utility projects with no TOD factors, set the value for all periods to one.

For the CSP models, although the TOD power price factors are financial model inputs, they are on the Storage page because it includes other time-dependent variables, and there may be a relationship between the dispatch factors and the TOD power price factors. For PV and other technology models, the TOD power price factors are on a separate Time of Delivery Factors input page. For a description of how to specify the TOD power price factors for all technology models, see Time of Delivery Factors.

For a description of TOD-related simulation results, see PPA Revenue with TOD Factors.

Defining Dispatch Schedules

The storage dispatch schedules determine when each of the six periods apply during weekdays and weekends throughout the year. You can either choose an existing schedule from one of the schedules in the CSP trough TES dispatch library or define a custom schedule. For information about libraries, see Working with Libraries.

The TES dispatch library only assigns period numbers to the weekday and weekend schedule matrices. The dispatch fractions assigned to each of the six periods are not stored in the library.

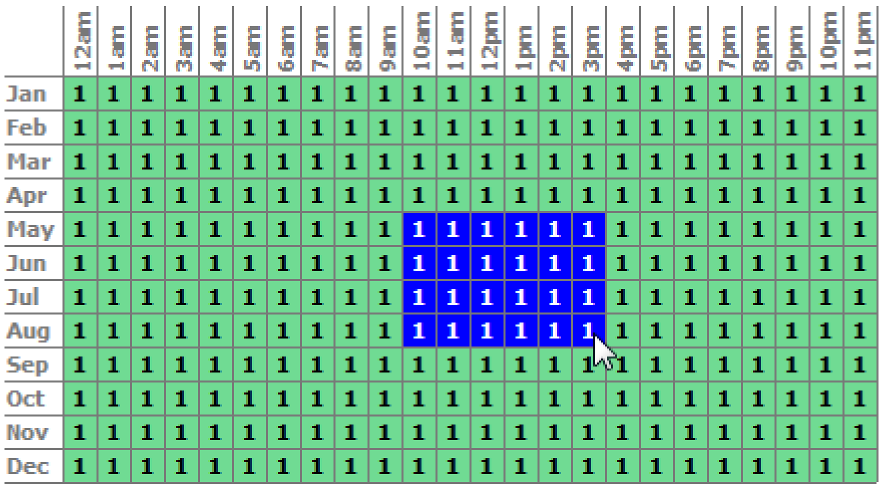
To choose a schedule from the library:

1. Click **Dispatch schedule library**.
2. Choose a schedule from the list of four schedules. The schedules are based on time-of-use pricing schedules from four California utilities.
3. Click **OK**.

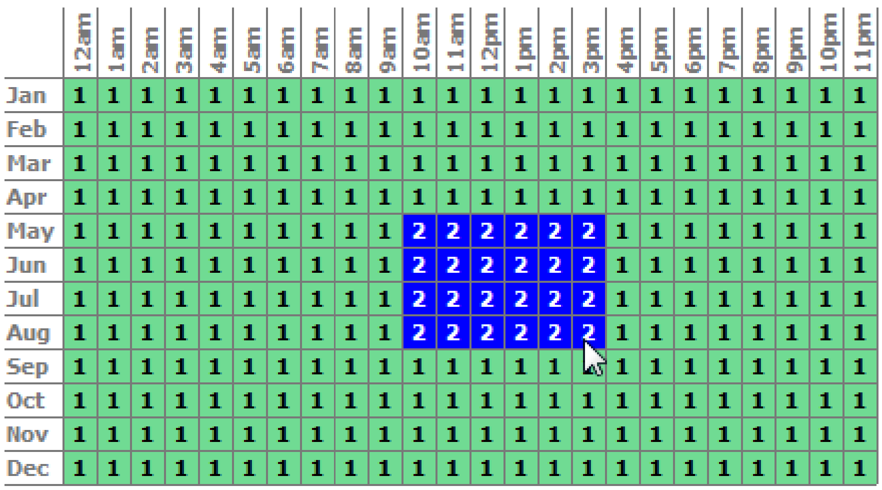
   You can modify a schedule using the steps described below. Modifying a schedule does not affect the schedule stored in the library.
4. For each of the up to six periods used in the schedule, enter values for the dispatch fractions described above. Use the period number and color to identify the times in the schedule that each period applies.

To specify a weekday or weekend schedule:

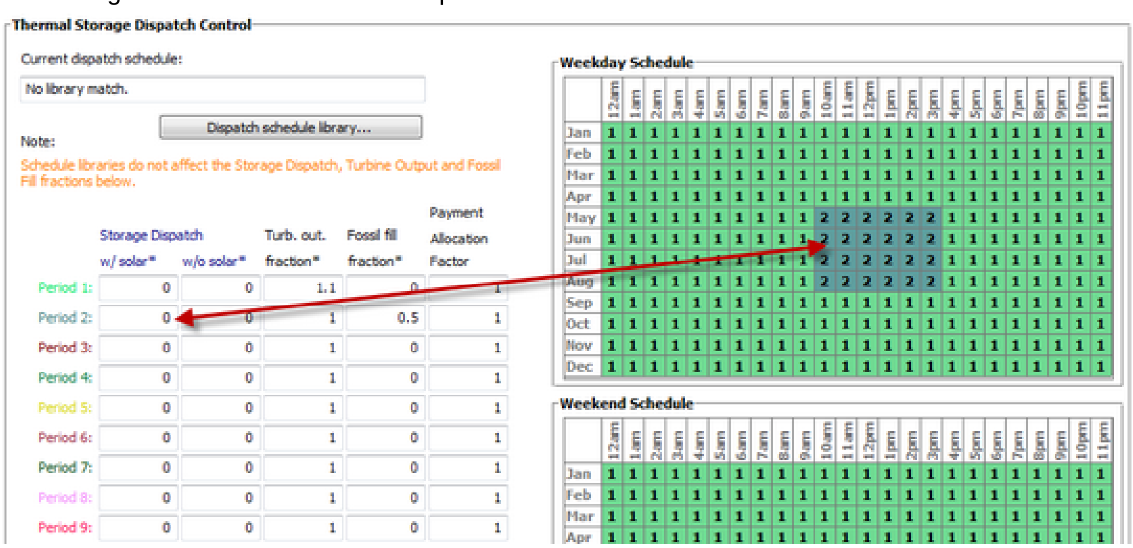
1. Assign values as appropriate to the Storage Dispatch, Turbine Output Fraction, Fossil Fill Fraction, and TOD Factor for each of the up to nine periods.
2. Click **Dispatch schedule library**.
3. Choose a **Uniform Dispatch**.
4. Click **OK**.
5. Use your mouse to draw a rectangle in the matrix for the first block of time that applies to period 2.



6. Type the number 2.



7. SAM shades displays the period number in the squares that make up the rectangle, and shades the rectangle to match the color of the period.



8. Repeat Steps 2-4 for each of the remaining periods that apply to the schedule.

7.2.6 Parasitics

To view the Parasitics page, click **Parasitics** on the main window's navigation menu. Note that for the empirical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Empirical Trough System.

The Parasitics page displays parameters describing losses due to parasitic electrical loads, such as drive motors, electronic circuits, and pump motors. SAM includes a set of default parasitic parameters for a range of solar trough power systems. Choose a reference parasitic system option that is the same or similar to the system you are modeling. SAM will automatically adjust the total parasitic load to match the size of the solar field and power block in the system you are modeling.

The design point parasitic values are the maximum possible values for each parasitic loss category. SAM calculates the hourly parasitic loss value for each category during simulation based on the design point, the PF and F0-F2 coefficients, and the solar field thermal output and power block load in each hour, and reports them in the time series simulation results. The calculated parasitic loss values are never as high as the total design point parasitic losses.

For a more detailed description of the model, please download the CSP trough reference manual from the SAM website's support page: https://sam.nrel.gov/reference.

The values of input variables on the Parasitics page are stored in a library of reference solar fields. You can change the parameter values without changing the values stored in the library. For information about libraries, See Working with Libraries.

Parasitic Electric Energy Use

Current reference parasitic system

The reference system from the CSP trough parasticis library. SAM stores a set of parasitic parameters for reference systems.

Solar Field Area (m^2)

The calculated solar field area from the Solar Field page. Used to calculate parasitic losses that are based on the solar field size with units of MWe/m^2.

Gross Turbine Output (MWe)

The design turbine gross output value from the Power Block page. Used to calculate parasitic losses that are based on the power block capacity with units of MWe/Mwe.

SCA Drives and Electronics (MWe)

Electrical losses from electric or hydraulic SCA drives that position the collector to track the sun and from electronic SCA tracking controllers and alarm monitoring devices. For hours when the solar field is operating, SAM calculates the loss as the product of the value you specify and the solar field area. For hours when the solar field is not operating, the value of the loss is zero.

Note. SAM does not use the "PF" value for the SCA Drives and Electronics loss calculation.

Solar Field HTF Pumps

Electrical losses from cold HTF pumping in the solar field. Calculated as a function of the solar field area. These losses are calculated only in hours when the solar field is operating, which is defined as when the solar field load is greater than zero.

$$Solar\ Field\ HTF\ Pumps\ Parasitic = Design\ Point * \left[F0 + F1\frac{\dot{Q}_{sf}}{\dot{Q}_{sf,design}} + F2\left(\frac{\dot{Q}_{sf}}{\dot{Q}_{sf,design}}\right)^2\right]$$

TES Pumps

Electrical losses from pumps in the TES system. Calculated as a function of the design turbine gross output.

Antifreeze Pumping (MWe)

Electrical losses from HTF pumps in the solar field. Calculated as a function of the solar field area, calculated as a fraction of the solar field HTF pumps design point parasitic loss. These losses are used only in hours when the solar field is not operating, which is defined as when the solar field load is zero.

Power Block Fixed (MWe)

These fixed losses apply 24 hours per day, for all of the 8,760 hours of the year.

Balance of Plant (MWe)

Electrical losses that apply in hours when the power block operates at part or full load.

Heater and Boiler (MWe)

Losses that apply only when the back-up boiler is in operation.

Cooling Towers (MWe)

The cooling tower parasitic losses are electrical losses that occur when the power block operates at part or full load. Calculated either as a function of power block load or at a fixed 50% or 100% of the design cooling tower parasitic losses.

Cooling Tower Operation Mode

Determines how cooling tower parasitic losses are calculated. For "Cooling Tower at 50% or 100%," parasitic losses are calculated as 50% of the design cooling tower parasitic losses when the power block load is 0.5 or less, and as or 100% of the design parasitic losses when the power block load is greater than 0.5. For "Cooling Tower parasitics a function of load," cooling tower parasitic losses are calculated as a function of power block load.

Total Design Parasitics (MWe)

The sum of collector drives and electronics, solar field HTF pump, night circulation pumping, power block fixed, balance of plant, heater/boiler, and cooling towers design loss values. This value represents the maximum possible value if all parasitic losses were to occur simultaneously in a given hour, and is typically greater than the actual parasitic losses. SAM displays the value for reference only, and does not use it in simulation calculations.

Each parasitic loss type has a set of parameters that includes a factor, PF and F0, F1, and F2 coefficient. The design point values are maximum values and are calculated using the factor and PF coefficient. SAM uses the F0-F2 coefficients in calculations for the hourly simulations, which are described in the reference manual.

Table . Design point parasitic loss equations for each parasitic loss category.

Source of Parasitic Loss	Equation
SCA Drives and Electronics	Factor x PF x Solar Field Area
Solar Field HTF Pumps	Factor x PF x Solar Field Area
TES Pumps	Factor x PF x Gross Turbine Output
Antifreeze Pumping	Factor x Solar Field HTF Pump losses
Power Block Fixed	Factor x Gross Turbine Output
Balance of Plant	Factor x PF x Gross Turbine Output
Heater and Boiler	Factor x PF x Gross Turbine Output
Cooling Towers	Factor x PF x Gross Turbine Output

The Total Design Point Parasitics is the sum of the design point parasitic loss categories:

- SCA Drives and Electronics
- Solar Field HTF Pumps
- TES Pumps
- Power Block Fixed
- Balance of Plant
- Heater and Boiler
- Cooling Towers

7.3 Power Tower Molten Salt

A power tower system (also called a central receiver system) is a type of concentrating solar power (CSP) system that consists of a heliostat field, tower and receiver, power block, and optional storage system. The field of flat, sun-tracking mirrors called heliostats focus direct normal solar radiation onto a receiver at the top of the tower, where a heat-transfer fluid is heated and pumped to the power block. The power block generates steam that drives a conventional steam turbine and generator to convert the thermal energy to electricity.

For a general description of the model, see Overview.

For a description of the solar field optimization process, see Optimization Wizard.

The molten salt power tower model input pages are:

- Location and Resource
- Tower System Costs
- Heliostat Field
- Tower and Receiver
- Power Cycle
- Thermal Storage
- Parasitics

7.3.1 Tower Molten Salt Overview

A power tower system (also called a central receiver system) is a type of concentrating solar power (CSP) system that consists of a heliostat field, tower and receiver, power block, and optional storage system. The field of flat, sun-tracking mirrors called heliostats focus direct normal solar radiation onto a receiver at the top of the tower, where a heat-transfer fluid is heated and pumped to the power block. The power block generates steam that drives a conventional steam turbine and generator to convert the thermal energy to electricity.

SAM's power tower performance model uses TRNSYS components developed at the University of Wisconsin and described in *Simulation and Predictive Performance Modeling of Utility-Scale Central Receiver System Power Plants*, Wagner (2008) http://sel.me.wisc.edu/publications/theses/wagner08.zip (32 MB).

The solar field optimization algorithm is based on the DELSOL3 model developed at Sandia National Laboratories, and described in *A User's Manual for DELSOL3: A Computer Code for Calculating the Optical Performance and Optimal System Design for Solar Thermal Central Receiver Plants*, Kistler (1986), (SAND86-8018) http://www.prod.sandia.gov/cgi-bin/techlib/access-control.pl/1986/868018.pdf (10 MB). The DELSOL software and user's manual is available from Sandia here: http://energy.sandia.gov/?page_id=6530.

For a description of the solar field optimization process, see Optimization Wizard.

You can explore the source code written in FORTRAN for the tower molten salt model in the following folder of your SAM installation folder (c:\SAM\SAM 2014.1.14 by default): C:\exelib\trnsys\source. The files are:

- Heliostat Field: sam_mw_pt_Type221.for
- Tower and Receiver: sam_mw_pt_Type222.f90
- Power Cycle: sam_mw_pt_TYPE224.f90
- Thermal Storage: sam_mw_trough_Type251.f90
- Parasitics: sam_mw_trough_Type251.f91 / sam_mw_pt_Type228.f90

To use the power tower model:

1. Start SAM.
2. Under **Enter a new project name to begin**, type a name for your project. For example, "Power Tower System."
3. Click **Create New File**.
4. Under **1. Select a technology**, click **Concentrating Solar Power**.
5. Click **Power Tower System**.
6. Under **2. Select a financing option**, click an appropriate financing option. You may want to start with the **Utility Independent Power Producer (IPP)** option.
7. Click **OK**.

   SAM creates a new .zsam file with a single case populated with default input values for a 100 MW power tower system.

This section describes the system input pages that are available when the technology option in the Technology and Market window is Concentrating Solar Power - Power Tower System.

The molten salt power tower model input pages are:

- Location and Resource
- Tower System Costs
- Heliostat Field

- Tower and Receiver
- Power Cycle
- Thermal Storage
- Parasitics

7.3.2 Heliostat Field

To view the Heliostat page, click **Heliostat Field** on the main window's navigation menu. Note that for the power tower input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Power Tower System.

The Heliostat Field page displays the variables that specify the position of the heliostats in the solar field along with the heliostat geometry and optical properties. Unlike parabolic trough and dish system designs, which can be based on modular designs of individual components, power tower system designs typically require optimization of the tower height, receiver geometry, and distribution of heliostats around the receiver as a complete system.

Page numbers relevant to this section from the Wagner (2008) and Kistler B (1986) references are:

- Wagner p 10, 23-42, 49
- Kistler p 25-37, 39-47, 74-75

You can define the heliostat field layout in two ways: If you have a field layout in mind, you can enter values by hand. Or, you can use SAM's optimization wizard to determine the optimal layout for you.

For an example of a SamUL script that optimizes the solar field and storage capacity, see the sample file *Power Tower Field and Storage Optimization with SamUL*: On the **File** menu, click **Open Sample File** and choose the file from the list.

Input Variable Reference

Heliostat Properties

The heliostat properties define the area of a single heliostat mirrored surface, shape of the heliostat, and the boundaries of the solar field area. Note that SAM assumes that each heliostat employs a two-axis drive system with a pivot at the center of the mirrored surface.

Heliostat Width, m

The width of the heliostat surface in meters, including the mirrored surface, edge supports and any cutouts.

Heliostat Height, m

The height of the heliostat surface in meters, including the mirrored surface, edge supports and any cutouts or slots.

Ratio of Reflective Area to Profile

The fraction of the area defined by the heliostat width and height that actually reflects sunlight. This value determines the ratio of reflective area on each heliostat to the total projected area of the heliostat on a plane normal to the heliostat surface. The ratio accounts for non-reflective area on the heliostat that may cause shading of neighboring heliostats.

Use Round Heliostats (D=W)

Check the box to use round heliostats in place of the standard rectangular shape. For round heliostats, the heliostat diameter is equal to the value of the Heliostat Width variable.

Heliostat Area, m²

The area of the heliostat mirrored area. For rectangular heliostats, the area is the product of the heliostat width and height (or the product of the square of half the width and pi for round heliostats) and the ratio of reflective area to heliostat profile.

Mirror Reflectance and Soiling

The mirror reflectance input is the solar weighted specular reflectance. The solar-weighted specular reflectance is the fraction of incident solar radiation reflected into a given solid angle about the specular reflection direction. The appropriate choice for the solid angle is that subtended by the receiver as viewed from the point on the mirror surface from which the ray is being reflected. For parabolic troughs, typical values for solar mirrors are 0.923 (4-mm glass), 0.945 (1-mm or laminated glass), 0..906 (silvered polymer), 0.836 (enhanced anodized aluminum), and 0.957 (silvered front surface).

Heliostat Availability

An adjustment factor that accounts for reduction in energy output due to downtime of some heliostats in the field for maintenance and repair. A value of 1 means that each heliostat in the field operates whenever sufficient solar energy is available. SAM multiplies the solar field output for each hour by the availability factor.

Image Error, radians

A measure of the deviation of the actual heliostat image on the receiver from the expected or ideal image that helps determine the overall shape and distribution of the reflected solar flux on the receiver. This value specifies the total conical error distribution for each heliostat at one standard deviation in radians. SAM applies the value to each heliostat in the field regardless of its distance from the tower. The image error accounts for all error sources, including tracking imprecision, foundation motion, mirror waviness, panel alignment problems, atmospheric refraction and tower sway.

Heliostat Stow Deploy Angle, degrees

Solar elevation angle below which the heliostat field will not operate.

Wind Stow Speed, m/s

Wind velocity from the weather file at which the heliostats defocus and go into stowed position. At wind speeds above the stow speed, SAM assumes that the heliostats move into stow position to protect the mirror surface and support structure from wind damage. SAM accounts for the parasitic tracking power required to stow the heliostats, and to reposition them when the wind speed falls below the stow speed.

Circular Field Optimization Wizard

When the you are specifying the heliostat field using radial sections, SAM can find the optimal number of heliostats for each section automatically. See Optimization Wizard for more information.

Note. The optimization wizard will not work if you are specifying the solar field using x-y coordinates.

Field Parameters

Total Reflective Area, m²

Total mirrored area of the heliostat field, equal to the heliostat reflective area multiplied by the number of heliostats. SAM uses the total field area to calculate the site improvements and heliostat costs on the

Tower System Costs page.

Number of Heliostats

The total number of individual heliostats in the field. SAM displays the number of heliostats based either on the results of the optimization wizard, or based on the data in the heliostat layout file when the heliostat locations are loaded from a text file.

Radial Step Size for Layout, m

The radial distance between centers of heliostat field zones. The zone centers are indicated by the symbol + in the zone layout sample diagram shown on the Heliostat Field page.

In the x-y coordinate mode, SAM disables the radial step size variable.

When you define the number of heliostats per zone by entering values in the field layout table by hand or by loading a file, the radial step size is the difference between the initial maximum distance from the tower and initial minimum distance from the tower divided by the number of radial zones.

When you use the optimization wizard to specify the field, SAM calculates the radial step size as a function of the initial minimum and maximum distances from the tower, which it in turn calculates as a function of the ratio of the optimized tower height to the minimum and maximum tower height specified on the Receiver/Tower Sizing tab of the optimization wizard.

Solar Field Layout Constraints

Max Heliostat Distance to Tower Height Ratio and **Min Heliostat Distance to Tower Height Ratio**

The maximum and minimum ratio of the distance from the heliostat furthest and closest from the tower to the tower height.

Max Distance to Tower and **Min Distance from Tower, m**

The maximum and minimum allowable radial distances in meters between the center of the tower base and heliostats furthest from the tower. Under certain conditions, SAM uses this value to calculate the radial step size. (See radial step size variable description below.)

Tower Height, m

The height of the tower in meters. Specify this value on the Tower and Receiver page.

Mirror Washing

SAM reports the water usage of the system in the results based on the mirror washing variables. The annual water usage is the product of the water usage per wash and 365 (days per year) divided by the washing frequency.

Water usage per wash

The volume of water in liters per square meter of solar field aperture area required for periodic mirror washing.

Washes Per Year

Number of times per year that heliostats mirrors are washed.

Land Area

Non-Solar Field Land Area, acres

The land area in acres occupied by the project, not including the heliostat field.

Solar Field Land Area Multiplier

The total solar field land area, including the area occupied by heliostats and space between heliostats, expressed as a multiple of the area occupied by heliostats. The default value is 1.3, which represents a total solar field land area that is 1.3 times the area occupied by heliostats.

Calculated Total Land Area, acres

Land area required for the entire system including the solar field land area.

Total Land Area (acres) = Non-Solar Field Area (acres) + Area of Zones Occupied by Heliostats (m²) × Solar Field Land Area Multiplier × 0.0002471 (acres/m)

The area of zones occupied by heliostats depends on the field geometry, which is either calculated by the field optimization wizard, or for a rectangular field, depends on the geometry you specify.

The land area appears on the System Costs page, where you can specify land costs in dollars per acre.

Specifying the Field

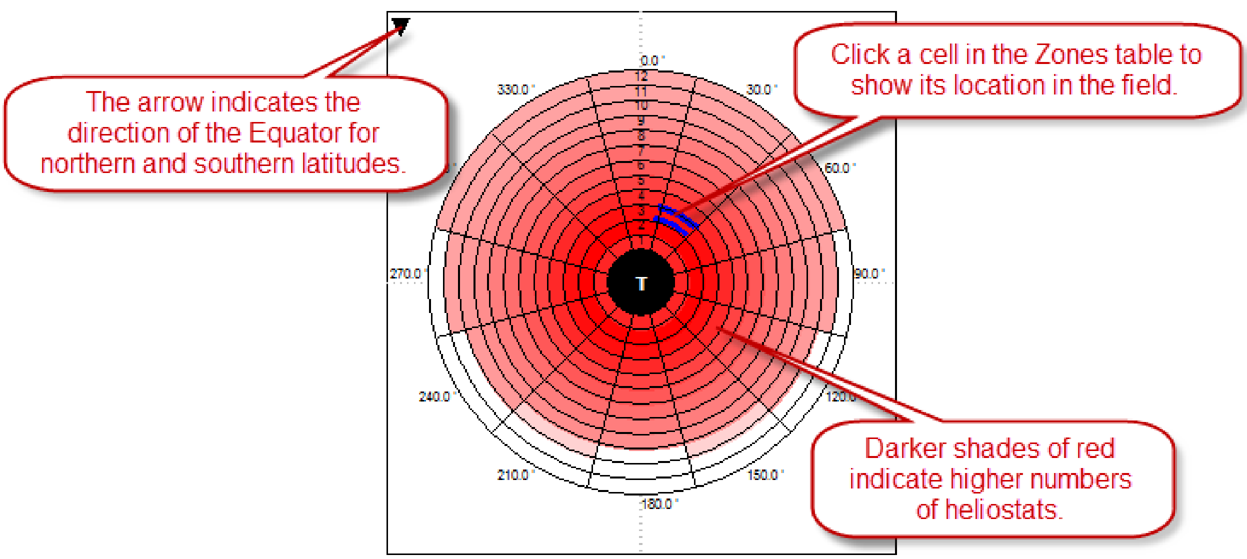
SAM allows the heliostat locations in the field to be specified either by a set of rectangular coordinates (x-y) or as a number of heliostats per radial section of the field (number of radial and azimuthal zones).

Span Angle

For external receivers the span angle should be 360 degrees. For a cavity receiver, specify a span angle less than 180 degrees. The default value for cavity receivers is 120 degrees. Specify the receiver type on the Tower and Receiver page.

Radial and Azimuthal Zones

To specify the field as a number of heliostats per radial zone enter the number of radial zones and azimuthal zones to divide the heliostat field into radial zones shown in the field diagram. You can then specify the field manually or automatically. To specify the field manually, either type values in the Number of Heliostats Per Zone table or import the data as a text file. To specify the field automatically, use the optimization wizard to specify a set of optimization parameters and allow SAM to optimize the heliostat field design and calculate the optimal number of heliostats per zone, receiver tower height, receiver height and diameter, and other variables.



The diagram shows that solar field is divided into evenly distributed sections of a circle called zones. The rows of the Zones table specify the radial position if each zone relative to the tower located at the center of the field. The zone closest to the tower is assigned the number one, with each successively farther zone incrementing by one. The columns specify the position of the zone's center in degrees east of due north, where zero is north, 90 degrees is east, 180 degrees is south, and 270 degrees is west. The number of heliostats per zone can be a non-integer value because SAM converts the value to a mirror surface area for each zone that is equivalent to the total mirrored surface of all heliostats in the zone.

Rectangular (x-y) Coordinates

To specify the field as a set of rectangular coordinates, change the value of Azimuthal Zones to 2, and enter the number of heliostats for # of Heliostats. You can then either type the x-y coordinates of each heliostat in the field, or import a text file of x-y coordinates. SAM displays the location of each heliostat on the field diagram. It models the system based on the heliostat locations specified by the set of x-y locations, and based on the values you specify for the tower height, receiver height, receiver diameter, and other input values. This approach is appropriate for predicting the output of a system with a known design. The optimization wizard does not work in the x-y coordinate mode.

Each row specifies the position of an individual heliostat relative to the tower. The first column in the table specifies the x-coordinate along the east-west axis of the field, with negative values indicating positions west of the tower, and positive values indicating positions east of the tower. The second column specifies the y-coordinate along the north-south axis, with positive values indicating positions north of the tower, and negative values indicating positions south of the tower. The tower is assumed to be at 0,0. Note that this convention also applies to systems in the southern hemisphere. In the x-y coordinate mode, SAM requires that the field be symmetric about the north-south axis.

Working with Heliostat Field Files

SAM allows you to use text files to save and load field layout data when you specify the field layout by hand instead of relying on the optimization wizard to calculate the optimal layout.

For radial zone data, each row in the file represents a radial step (distance away from the center of the circle), and each column represents an azimuthal division (distance clockwise around the circle from the zero degree line pointing north), as shown on the sample layout diagram. The first row must contain data for the radial step closest to the center of the field, and subsequent rows should be in consecutive order away from the center. The first column of each row must contain data for the azimuthal division containing the north line at zero degrees, and the second column the next division moving counterclockwise from the first column, and so on. Zones with no heliostats should be indicated by a zero. Each column in the file should be separated by a space, and each row by a new line. For example, a text file with the following contents would describe a field with three radial steps and four azimuthal divisions:

```
9.0 10.0 9.0 10.0
15.5 15.5 15.5 15.5
22.5 18.0 18.5 22.5
```

For rectangular coordinate data, each row represents an individual heliostat position in the field, with the x coordinate in the first column and the y coordinate in the second column. A positive x value is east, and a positive y value is north of the tower. Use negative values for positions west and south of the tower. The heliostat coordinates do not have to be in a particular order in the file. Each column in the file should be separated by a space, and each row by a new line. A file with the following contents would describe a solar field with three heliostats at (x = 0.0, y = 75.0), (x = 7.5, y = 70.0), and (x = 15.0, y = 65.0):

```
0.0 75.0
7.5 70.0
```

15.0 65.0

7.3.3 Tower and Receiver

To view the Tower and Receiver page, click **Tower and Receiver** on the main window's navigation menu. Note that for the power tower input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Power Tower System.

Overview

The Tower and Receiver page displays variables that specify the geometry of the heat collection system. The receiver model uses semi-empirical heat transfer and thermodynamic relationships to determine the thermal performance of the receiver. This allows the model to represent a wide array of geometries without deviating from a hypothetical reference system.

Page numbers relevant to this section from the Wagner (2008) and Kistler B (1986) references are:

- Wagner p 43-47, 68-71

The model makes several assumptions about the system geometry for external receivers:

- The receiver consists of a discrete number of panels.
- Each panel in the receiver consists of a set of parallel tubes in thermal contact that share a common heat transfer fluid (HTF) header.
- The panel tubing is vertical and the heat transfer fluid flows through each sequential panel in a serpentine pattern (up one panel and down the adjacent panel).
- The number of tubes per panel is a function of the Number of Panels, Receiver Diameter, and Tube Outer Diameter variables.

The model varies the heat transfer fluid mass flow rate through the receiver to maintain the required outlet heat transfer fluid temperature. The model includes several practical safeguards to ensure realistic behavior in the receiver. For example, the mass flow rate through the receiver is limited to the value of the Max Flow Rate to Receiver variable, and the maximum receiver heat transfer fluid inlet temperature is kept at a value below the value of the Max Temp to Receiver variable.

SAM allows several options for the heat transfer fluid flow patterns through the receiver as indicated by the diagrams on the Receiver / Tower page. The Flow Pattern variable specifies the path taken by the fluid as it passes through the receiver. Options include a full circle around the receiver, a split path around the receiver, and a split pass with a single cross-over.

Input Variable Reference

SAM models power tower systems with either an external receiver or cavity receiver. When you change the receiver option, you should run the optimization wizard to optimize the field for the new receiver type.

External Receiver

Note. The external receiver parameters are only active when you select **External Receiver**.

For analyses involving the optimization wizard to optimize the heliostat field layout, SAM populates these variables with optimal values. You can change the values after running the optimization wizard, but results will no longer be for the optimal system.

Receiver Height, m

Height in meters of the receiver panels.

Receiver Diameter, m

Total diameter in meters of the receiver. The distance from center of the receiver to center of a receiver panel. The width of a single panel is the circumference of receiver divided by number of panels.

Number of Panels

Number of vertical panels in the receiver.

Note. For **Flow Pattern** options 1-4, **Number of Panels** must be a multiple of 2. If you specify an invalid number, the simulation will fail, and SAM will generate an error message.

Coating Emittance

The emissivity of the receiver coating, assumed to be black-body emissivity constant over the range of wavelengths.

Enable Night Recirculation through Receiver

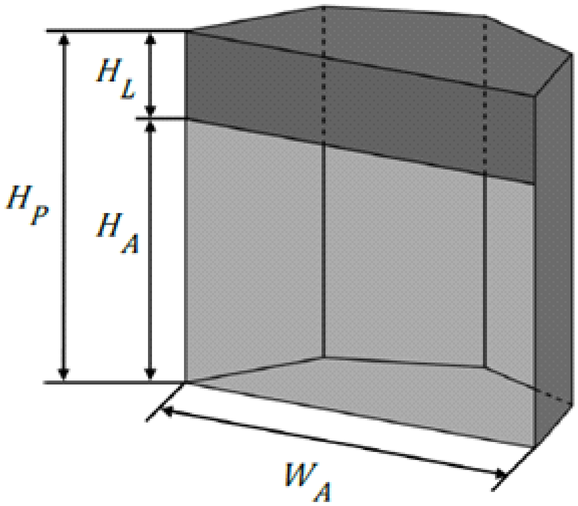
With night circulation enabled, whenever the radiation incident on the receiver is zero, hot heat transfer fluid circulates through the receiver to prevent fluid in the receiver from freezing. For systems with storage, the system pumps heat transfer fluid from hot storage. For systems with no storage, or when there is insufficient energy in storage, the circulating fluid is heated with an electric heater. The heat transfer fluid is assumed to enter the receiver at the temperature required for it to exit the receiver at the required outlet temperature, accounting for thermal losses. SAM adjusts the heat transfer fluid mass flow rate accordingly.

Recirculation Heater Efficiency

With night circulation enabled, the electric-to-thermal conversion efficiency of the heater used to supply thermal energy for preventing the receiver heat transfer fluid from freezing. SAM calculates the heater electricity based on the required thermal recirculation energy and the heater efficiency, and reports the hourly electricity required by the heater as Par_recirc_htr in the hourly results.

Cavity Receiver

SAM assumes that the cavity receiver consists of four panels arranged at the circumference of a semicircle:



Where:

- H_L: Lip height
- H_A: Aperture height
- H_P: Internal panel height
- W_A: Aperture width

SAM also assumes that the aperture of the cavity faces north when the location specified on the Location and Resource page the northern hemisphere, and south when the location is in the southern hemisphere.

Notes.

The cavity receiver parameters are only active when you select **Cavity Receiver**.

If you run the optimization wizard, SAM automatically populates the cavity receiver values. If you modify these values, they will be inconsistent with other values calculated by the wizard.

Aperture Width

The width of the rectangle in the plane of the cavity opening.

Aperture Height To Width Ratio

The ratio of aperture height to aperture width.

Aperture Height

The height of the rectangle in the plane of the cavity opening: Aperture Height = Aperture Width × Aperture Height to Width Ratio. Note that the receiver height may be greater than the aperture height.

Lip to Height Ratio

The "lip" is the difference between the aperture height and receiver height.

Internal Panel Height

The internal height of the panel: Internal Height = Aperture Height × (1 + Lip to Height Ratio).

Aperture Lip Height

The height of the aperture lip: Aperture Lip Height = Internal Panel Height × Lip to Height Ratio

Receiver Thermodynamic Characteristics

Tube Outer Diameter, mm

The outer diameter in millimeters of the tubing that carries the heat transfer fluid through the receiver panels. Typical values range from 25 mm to 50 mm.

Tube Wall Thickness, mm

The thickness in millimeters of the individual receiver panel tube walls.

Required Outlet HTF Temp, °C

The temperature set point in degrees Celsius for the heat transfer fluid at the receiver outlet.

Max Temp to Receiver, °C

The maximum allowable temperature of the heat transfer fluid at the receiver inlet.

Coating Absorptance

Absorptance fraction of receiver tube coating. Typical values are 0.91 to 0.95.

Heat Loss Factor

A receiver heat loss adjustment factor that can be used when the calculated heat loss value deviates from an expected value. The default value is 1, corresponding to no heat loss correction. The calculated receiver heat loss is the sum of convection and radiation losses from the receiver, reported in the hourly results as Rec_conv_loss and Rec_rad_loss, respectively.

Max Flow Rate to Receiver, kg/s

The maximum heat transfer fluid flow rate at the receiver inlet. SAM calculates this value as a function of the maximum heat transfer fluid velocity in the receiver.

Max Receiver Flux, kWt/m^2

The upper limit of solar radiation incident on the receiver allowed to be reflected from the heliostat field. SAM ensures that the optimal receiver size and heliostat positions do not result in a receiver flux that exceeds this value.

Materials and Flow

HTF Type

One of two types of solar salt used for the heat transfer fluid, also called the working fluid. You can also add a user defined HTF by choosing the user defined option and clicking the Edit button to open the HTF properties editor.

Property table for user-defined HTF

When the HTF type is "user defined," the Edit button provides access to the HTF properties editor.

Material Type

The material of the receiver panel tubes, typically a stainless-steel alloy. The current version of SAM allows only one material type.

Flow Pattern

One of eight available heat transfer fluid flow configurations shown in the diagram.

For an external receiver, the views are from the top of the receiver, assuming that panels are arranged in a circle around the center of the receiver. Arrows show the direction of heat transfer fluid flow into, through, and out of the receiver.

Note. For **Flow Pattern** options 1-4, **Number of Panels** must be a multiple of 2. If you specify an invalid number, the simulation will fail, and SAM will generate an error message.

Design Operation

Solar Multiple

This value is populated by the optimization wizard, but you can modify it to use a different value than the one calculated by the wizard. If you modify the solar multiple without running the optimization wizard, the receiver design thermal power will change, but the solar field will not. The solar multiple is the ratio of the receiver's design thermal output to the power block's design thermal input. For systems with no storage, the solar multiple should be close to or equal to one.

Min receiver turndown fraction

The minimum allowable fraction of the maximum flow rate to receiver.

Max receiver operation fraction

The maximum allowable fraction of the maximum flow rate to receiver. SAM removes heliostats from operation if the HTF mass flow rate exceeds the maximum allowable value.

Receiver design thermal power

Product of solar multiple and power cycle design thermal power on the Power Cycle page.

Receiver startup delay time

The time in hours required to start the receiver. The receiver starts whenever the radiation incident on the field in the previous hour is zero, and there is sufficient thermal energy in the current hour to meet the thermal design requirement. SAM calculates the start up energy as the product of the available thermal energy, startup delay time, and startup delay energy fraction.

Receiver startup delay energy fraction

Fraction of receiver design thermal power required by the receiver during the startup period.

Tower Dimension

Tower Height, m

Height in meters of the tower structure from the ground, equal to the vertical distance between the heliostat pivot points and the vertical center of receiver.

7.3.4 Power Cycle

To view the Power Cycle page, click **Power Cycle** on the main window's navigation menu. Note that for the power tower input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Power Tower System.

The power cycle converts thermal energy to electric energy. The power cycle is assumed to consist of a Rankine-cycle steam engine, two open feed-water heaters, and a pre-heater, boiler and super-heater.

The parameters on the Power cycle page describe the steam turbine size and other properties.

Page numbers relevant to this section from the Wagner (2008) and Kistler B (1986) references are:

- Wagner 83, 86, 114, 164
- Kistler 224

The power cycle page displays variables that specify the design operating conditions for the steam Rankine cycle used to convert thermal energy to electricity.

Input Variable Reference

Plant Capacity

Design Turbine Gross Output, MWe

The power cycle's design output, not accounting for parasitic losses.

Estimated Gross to Net Conversion Factor

An estimate of the ratio of the electric energy delivered to the grid to the power cycle's gross output. SAM uses the factor to calculate the power cycle's nameplate capacity for capacity-related calculations, including the estimated total cost per net capacity value on the System Costs page, and the capacity factor reported in the results.

Estimated Net Output at Design (Nameplate), MWe

The power cycle's nameplate capacity, calculated as the product of the design gross output and estimated gross to net conversion factor.

Estimated Net Output at Design (MWe) = Design Gross Output (MWe) × Estimated Gross to Net Conversion Factor

Power Block Design Point

Rated Cycle Conversion Efficiency

The thermal to electric conversion efficiency of the power cycle under design conditions.

Design Thermal Power, MWt

The turbine's design thermal input. It is the thermal energy required at the power block inlet for it to operate at its design point, as defined by the value of the nameplate electric capacity and an estimate of the parasitic losses: Design thermal power = nameplate electric capacity + total parasitic loss estimate. (See the Parasitics page for a description of the total parasitic loss estimate.)

Design HTF Inlet Temp, °C

The design temperature in degrees Celsius of the hot heat transfer fluid at the power block inlet.p 114. design htf inlet temperature can be different from receiver outlet temperature when power block design specifications require a different inlet temperature for maximum efficiency. The design values are the operating conditions at which the power block operates at its nameplate capacity.

Design HTF Outlet Temp, °C

The design temperature in degrees Celsius of the cold heat transfer fluid at the power block outlet.p 114 The design values are the operating conditions at which the power block operates at its nameplate capacity.

Boiler Operating Pressure, Bar

The saturation pressure of the steam as it is converted from liquid to vapor in the boiler or steam generator. SAM uses this value to determine the steam's saturation temperature and thus the superheating capability of the heat exchangers. The temperature difference that drives the steam mass flow rate in the Rankine cycle is the difference between the hot heat transfer fluid inlet temperature and the saturation temperature of the steam boiler pressure.

Fossil Backup Boiler LHV Efficiency

The back-up boiler's lower heating value efficiency, used to calculate the quantity of gas required by the back-up boiler for hours that the fossil backup system supplements solar energy from the solar field or thermal storage system.

The **boiler LHV efficiency** value determines the quantity of fuel used by the backup boiler. A value of 0.9 is reasonable for a natural gas-fired backup boiler. SAM includes the cost of fuel for the backup system in the levelized cost of energy and other metrics reported in the results, and reports the energy equivalent of the hourly fuel consumption in the time series simulation results. The cost of fuel for the backup boiler is defined on the Tower System Costs page.

The timing of the backup boiler's operation depends on the fossil fill fraction values from the Thermal Storage page. See Storage and Fossil Backup Dispatch Controls for details.

Steam cycle blowdown fraction

The fraction of the steam mass flow rate in the power cycle that is extracted and replaced by fresh water. This fraction is multiplied by the steam mass flow rate in the power cycle for each hour of plant operation to determine the total required quantity of power cycle makeup water. The blowdown fraction accounts for water use related directly to replacement of the steam working fluid. The default value of 0.013 for the wet-cooled case represents makeup due to blowdown quench and steam cycle makeup during operation and startup. A value of 0.016 is appropriate for dry-cooled systems to account for additional wet-surface air cooling for critical Rankine cycle components.

Aux heater outlet set temp (ºC)

The temperature set point for the auxiliary heaters for the fossil backup system.

Fossil Dispatch Mode

Determines how SAM operates the fossil backup system:

Minimum Backup Level

In the Minimum Backup Level mode, whenever the **fossil fill fraction** is greater than zero for any dispatch period defined on the Thermal Storage page, the system is considered to include a fossil burner that heats the HTF before it is delivered to the power cycle.

In this mode, the fossil fill fraction defines the fossil backup as a function of the thermal energy from the solar field (and storage, if applicable) in a given hour and the **design turbine gross output**.

For example, for an hour with a fossil fill fraction of 1.0 when solar energy delivered to the power cycle is less than that needed to run at the power cycle design gross output, the backup heater would supply enough energy to "fill" the missing heat, and the power cycle would operate at the design gross output. If, in that scenario, solar energy (from either the field or storage system) is driving the power cycle at full load, the fossil backup would not operate. For a fossil fill fraction of 0.75, the heater would only be fired when solar output drops below 75% of the power cycle's design gross output.

Supplemental Operation

In the Supplemental Operation mode, SAM assumes a fossil backup system of a fixed maximum capacity, for example, capable of supplying 10 MW of thermal energy to the HTF.

Plant Control

Min Required Temp for Startup, °C

The temperature at which heat transfer fluid circulation through the power cycle heat exchangers begins, typically near the power block design heat transfer fluid outlet temperature. Default is 500 degrees.

Low-Resource Standby Period, hours

During periods of insufficient flow from the heat source due to low thermal resource, the power block may enter standby mode. In standby mode, the cycle can restart quickly without the startup period required by a cold start. The standby period is the maximum number of hours allowed for standby mode. This option is only available for systems with thermal storage. Default is 2 hours.

Fraction of Thermal Power Needed for Standby

The fraction of the turbine's design thermal input required from storage to keep the power cycle in standby mode. This thermal energy is not converted into electric power. Default is 0.2.

Power Block Startup Time, hours

The time in hours that the system consumes energy at the startup fraction before it begins producing electricity. If the startup fraction is zero, the system will operate at the design capacity over the startup time. Default is 0.5 hours.

Fraction of Thermal Power Needed for Startup

The fraction of the turbine's design thermal input required by the system during startup. This thermal energy is not converted to electric power. Default is 0.75.

Min Turbine Operation

The fraction of the nameplate electric capacity below which the power block does not generate electricity. Whenever the power block output is below the minimum load and thermal energy is available from the solar field, the field is defocused. For systems with storage, solar field energy is delivered to storage until storage is full. Default is 0.25.

Max Turbine Over Design Operation

The maximum allowable power block output as a fraction of the electric nameplate capacity. Whenever storage is not available and the solar resource exceeds the design value of 950 W/m2, some heliostats in the solar field are defocused to limit the power block output to the maximum load. Default is 1.05

Turbine Inlet Pressure Control

Determines the power cycle working fluid pressure during off-design loading.

Fixed Pressure: The power block maintains the design high pressure of the power cycle working fluid during off-design loading.

Sliding Pressure: The power block decreases the high pressure of the power cycle working fluid during off-design loading.

Cooling System

Condenser type

Choose either an air-cooled condenser (dry cooling), evaporative cooling (wet cooling), or hybrid cooling system.

In hybrid cooling a wet-cooling system and dry-cooling share the heat rejection load. Although there are many possible theoretical configurations of hybrid cooling systems, SAM only allows a parallel cooling option.

Hybrid Dispatch

For hybrid cooling, the hybrid dispatch table specifies how much of the cooling load should be handled by the wet-cooling system for each of 6 periods in the year. The periods are specified in the matrices on the Thermal Storage page. Each value in the table is a fraction of the design cooling load. For example, if you want 60% of heat rejection load to go to wet cooling in Period 1, type 0.6 for Period 1. Directing part of the heat rejection load to the wet cooling system reduces the total condenser temperature and improves performance, but increases the water requirement. SAM sizes the wet-cooling system to match the maximum fraction that you specify in the hybrid dispatch table, and sizes the air-cooling system to meet the full cooling load.

Ambient temp at design , ºC

The ambient temperature at which the power cycle operates at its design-point-rated cycle conversion efficiency. For the air-cooled condenser option, use a dry bulb ambient temperature value. For the evaporative condenser, use the wet bulb temperature.

Ref. Condenser Water dT, ºC

For the evaporative type only. The temperature rise of the cooling water across the condenser under design conditions, used to calculate the cooling water mass flow rate at design, and the steam condensing temperature.

Approach temperature, ºC

For the evaporative type only. The temperature difference between the circulating water at the condenser inlet and the wet bulb ambient temperature, used with the ref. condenser water dT value to determine the condenser saturation temperature and thus the turbine back pressure.

ITD at design point , ºC

For the air-cooled type only. Initial temperature difference (ITD), difference between the temperature of steam at the turbine outlet (condenser inlet) and the ambient dry-bulb temperature.

Note. When you adjust the ITD, you are telling the model the conditions under which the system will achieve the thermal efficiency that you've specified. If you increase the ITD, you should also modify the thermal efficiency (and/or the design ambient temperature) to accurately describe the design-point behavior of the system. The off-design penalty in the modified system will follow once the parameters are corrected.

Condenser Pressure Ratio

For the air-cooled type only. The pressure-drop ratio across the air-cooled condenser heat exchanger, used to calculate the pressure drop across the condenser and the corresponding parasitic power required to maintain the air flow rate.

Min condenser pressure

The minimum condenser pressure in inches if mercury prevents the condenser pressure from dropping below the level you specify. In a physical system, allowing the pressure to drop below a certain point can result in physical damage to the system. For evaporative (wet cooling), the default value is 1.25 inches of mercury. For air-cooled (dry cooling), the default is 2 inches of mercury. For hybrid systems, you can use the dry-cooling value of 2 inches of mercury.

Cooling system part load levels

The cooling system part load levels tells the heat rejection system model how many discrete operating points there are. A value of 2 means that the system can run at either 100% or 50% rejection. A value of three means rejection operating points of 100% 66% 33%. The part load levels determine how the heat rejection operates under part load conditions when the heat load is less than full load. The default value is 2, and recommended range is between 2 and 10. The value must be an integer.

7.3.5 Thermal Storage

To view the Thermal Storage page, click **Thermal Storage** on the main window's navigation menu. Note that for the power tower input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Power Tower System.

The parameters on the Thermal Storage page describe the properties thermal energy storage system and the storage dispatch controls.

The power tower storage model uses storage tank geometry, which requires that the heat transfer fluid volume, tank loss coefficients, and tank temperatures be specified. SAM calculates the storage tank geometry to ensure that the storage system can supply energy to the power block at its design thermal input capacity for the number of hours specified by the Full Load TS Hours variable.

> **Note.** Because the storage capacity is not tied to the solar multiple on the Heliostat Field page, be careful to choose a storage capacity that is reasonable given the system's thermal capacity. Mismatched storage and solar thermal capacities will result in high levelized cost of energy values.

Input Variable Reference

Storage System

Storage Type

SAM can model either two-tank or single tank (thermocline) storage systems for power towers.

A two-tank system consists of separate hot and cold storage tanks.

A thermocline system consists of a single tank filled with solid storage medium. The tank contains both the hot and cold storage that are separated vertically (hot above cold) by a sharp thermal gradient known as a thermocline. The system is charged by pumping hot HTF into the top of the tank. This process adds energy to the thermocline area of the tank which moves the thermocline towards the bottom of the tank. The discharging process is the reverse of the charging pocess.

> **Notes.**
>
> The thermocline storage model is only available for power towers, and not for any of the other CSP technologies.
>
> SAM disables some of the input variables based on the option you choose for Storage Type. For example, the **Tank Fluid Min Height** variable is available for the two-tank option, and disabled for the thermocline option.

Full Load Hours of TES, hours

The storage capacity expressed in hours at full load: The number of hours that the storage system can supply energy at the power block design turbine input capacity. Note that SAM displays the equivalent storage capacity in MWht on the Tower System Costs page.

Storage Volume, m³

SAM calculates the total heat transfer fluid volume in storage based on the storage hours at full load and the power block design turbine thermal input capacity. The total heat transfer fluid volume is divided among the total number of tanks so that all hot tanks contain the same volume of fluid, and all cold tanks contain the same volume of fluid.

Tank Diameter, m

The diameter of the cylinder-shaped heat transfer fluid volume in each storage tank.

Tank Height, m

The height of the cylinder-shaped heat transfer fluid volume in each tank. SAM calculates the height based on the diameter and storage volume of a single tank.

Tank Fluid Min Height, m (two-tank only)

The minimum allowable height of fluid in the storage tank(s). The mechanical limits of the tank determine this value.

Parallel Tank Pairs

The number of parallel hot-cold storage tank pairs. Increasing the number of tank-pairs also increases the volume of the heat transfer fluid exposed to the tank surface, which increases the total tank thermal losses. SAM divides the total heat transfer fluid volume among all of the tanks, and assumes that each hot tank contains an equal volume of fluid, and each cold tank contains and equal volume.

Min Storage Volume, m³

The minimum storage heat transfer fluid volume allowed in each storage tank. The usable fluid volume is equal to the total volume minus the minimum fluid volume. Calculated based on the minimum tank volume fraction, the total volume, and the number of parallel tank pairs.

Max Storage Volume, m³

The maximum usable heat transfer fluid volume allowed in each storage tank. The maximum volume is less than the total volume when the minimum tank volume is greater than zero, or the number of parallel tank pairs is greater than 1.

Wetted Loss Coefficient, W/m²/K

The thermal loss coefficient that applies to the portion of the storage tank holding the storage heat transfer fluid.

Dry Loss Coefficient, W/m²/K (two-tank only)

The thermal loss coefficient that applies to the portion of the storage tank that contains storage heat transfer fluid.

Initial Hot HTF Temp, °C

The temperature of the storage heat transfer fluid in the hot storage tank at the beginning of the simulation.

Initial Cold HTF Temp, °C

The temperature of the storage heat transfer fluid in the cold storage tank at the beginning of the simulation.

Initial Hot HTF Percent, %

The fraction of the storage heat transfer fluid in the hot storage tank at the beginning of the simulation.

Initial Hot Storage Volume, m³

The volume of the storage heat transfer fluid in the hot storage tank at the beginning of the simulation.

Initial Cold Storage Volume, m³

The volume of the storage heat transfer fluid in the cold storage tank at the beginning of the simulation.

Cold Tank Heater Temp Set-Point, °C

The minimum allowed cold tank temperature. Whenever the heat transfer fluid temperature in storage drops below the set-point value, the system adds sufficient thermal energy from an electric tank heater to storage to reach the set-point.

Cold Tank Heater Capacity, MWe

The maximum electric load of the cold tank electric heater.

Hot Tank Heater Temp Set-Point, °C (two-tank only)

The minimum allowed hot tank temperature. Whenever the heat transfer fluid temperature in storage drops below the set-point value, the system adds sufficient thermal energy from an electric tank heater to storage to reach the set-point.

Hot Tank Heater Capacity, MWe (two-tank only)

The maximum electric load of the hot tank electric heater.

Tank Heater Efficiency

The electric-to-thermal conversion efficiency of the hot tank and cold tank heaters.

Enable storage bypass valve

When the storage bypass valve is disabled, all of the HTF from the tower is delivered to storage before being delivered to the power block. Enabling the storage bypass valve allows the HTF to be delivered from the tower either to the power block or storage system. When the bypass valve is enabled, SAM only calculates hot HTF storage pumping power losses when the storage system is running. Without the bypass valve, storage pumping losses apply whenever HTF is circulating in the system.

Thermocline Parameters

The following input variables are active only when the **Storage Type** is **Thermocline**.

Void Fraction

The fraction of total tank volume occupied by the heat transfer fluid.

Minimum discharge outlet temp, °C

This value determines the extent to which the thermocline can be discharged.

From a theoretical standpoint, full discharge is desirable because it increases the storage capacity and negates thermal spreading. However, when considering the storage as a component of a larger CSP system, the effects of full discharge must be considered. Primarily, the minimum discharge outlet temperature is limited by the minimum inlet temperature to the power block, which is greater than the cold storage temperature

Maximum charge outlet temp, °C

This value determines the extent to which the thermocline can be charged.

This value is limited by the receiver and the maximum flow rate achievable by the HTF pumps. The relationship between these parameters is not easily determined. Generally, a high discharge temperature will force a high flow rate through the receiver, which increases parasitic and thermal losses while increasing the capacity of the storage.

Filler Material

The material used as the solid storage medium in the tank.

Filler material specific heat, kJ/kgK

Specific heat of the thermocline filler material. SAM displays this value for your reference but does not allow you to change it.

Filler material density, kg/m3

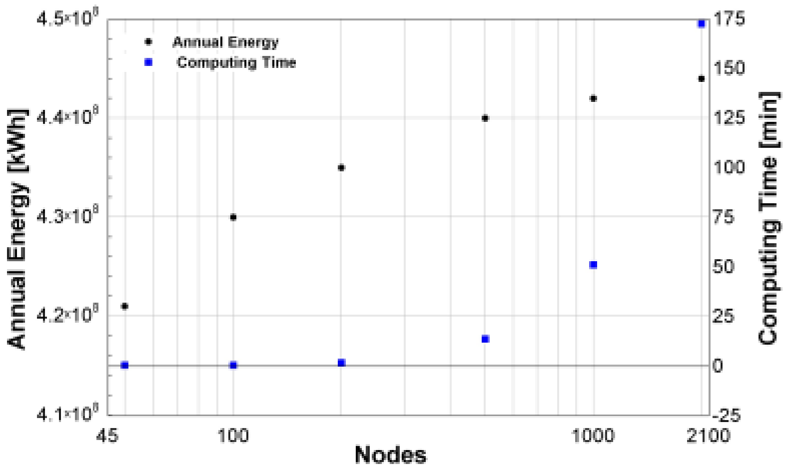
Density of the thermocline filler material. SAM displays this value for your reference but does not allow you to change it.

Number of calculation nodes for thermocline

Number of thermocline nodes: The number of discrete nodes used to discretize the storage tank model in the flow direction.

A large number of nodes (about 2000) are typically required to provide enough resolution to accurately model the abrupt changes in the thermocline region. However, such a high value results in long simulation run times (about 2 hours, depending on the computer). Fewer nodes will reduce accuracy but decrease run time.

For example, the following graph shows the system annual output in kWh (annual energy) and simulation run time (computing time) over a range of number of nodes calculated using the default molten salt power tower system.



Thermal Storage Dispatch Control

The storage dispatch control variables each have six values, one for each of six possible dispatch periods. They determine how SAM calculates the energy flows between the solar field, thermal energy storage system, and power block. The fossil-fill fraction is used to calculate the energy from a backup boiler.

Storage Dispatch Fraction with Solar

The fraction of the TES maximum storage capacity indicating the minimum level of charge that the storage system can discharge to while the solar field is producing power. A value of zero will always dispatch the TES in any hour assigned to the given dispatch period; a value of one will never dispatch the TES. Used to calculate the storage dispatch levels.

Storage Dispatch Fraction without Solar

The fraction of the TES maximum storage capacity indicating the minimum level of charge that the storage system can discharge to while no solar resource is available. A value of zero will always dispatch the TES in any hour assigned to the given dispatch period; a value of one will never dispatch the TES. Used to calculate the storage dispatch levels.

Turbine Output Fraction

The fraction of design-point thermal load to the power block before part-load and temperature efficiency corrections. These values allow the user to dispatch the power cycle at a desired level according to the time-of-dispatch period.

Fossil Fill Fraction

A fraction of the power block design turbine gross output from the Power Cycle page that can be met by the backup boiler. Used by the power block module to calculate the energy from the backup boiler.

TOD Factor

The time-of-delivery (TOD) factors allow you to specify a set of TOD power price factors to model time-dependent pricing for projects with one of the Utility Financing options.

The TOD factors are a set of multipliers that SAM uses to adjust the PPA price based on time of day and month of year for utility projects. The TOD factors work in conjunction with the assumptions on the Financing page.

Note. For utility projects with no TOD factors, set the value for all periods to one.

For the CSP models, although the TOD power price factors are financial model inputs, they are on the Storage page because it includes other time-dependent variables, and there may be a relationship between the dispatch factors and the TOD power price factors. For PV and other technology models, the TOD power price factors are on a separate Time of Delivery Factors input page. For a description of how to specify the TOD power price factors for all technology models, see Time of Delivery Factors.

For a description of TOD-related simulation results, see PPA Revenue with TOD Factors.

Storage and Fossil Dispatch Controls

The thermal storage dispatch controls determine the timing of releases of energy from the thermal energy storage and fossil backup systems to the power block. When the system includes thermal energy storage or fossil backup, SAM can use a different dispatch strategy for up to six different dispatch periods.

Storage Dispatch

For each hour in the simulation, SAM looks at the amount of energy in storage at the beginning of the hour and decides whether or not to operate the power cycle in that hour. For each dispatch period, there are two dispatch targets for starting or continuing to run the power cycle: one for periods of sunshine (**storage dispatch fraction w/solar**), and one for periods of no sunshine (**storage dispatch fraction w/o solar**). The dispatch target for each dispatch period is the product of the storage dispatch fraction for that period and the thermal storage capacity defined by the TES thermal capacity input variable.

- During periods of sunshine when there is insufficient energy from the solar field to drive the power cycle at its load requirement, the system dispatches energy from storage only when energy in storage is greater than or equal to the dispatch target.
- During periods of no sunshine, the power cycle will not run unless energy in storage is greater than or equal to the dispatch target.

The **turbine output fraction** for each dispatch period determines the power cycle output requirement for hours that fall within the dispatch period. A turbine output fraction of one defines an output requirement equivalent to the power cycle's design gross output defined on the Power Cycle page. For hours when the solar field energy is insufficient to drive the power cycle at the output requirement, the power cycle runs on energy from both the solar field and storage system. For hours when the solar field energy exceeds the output requirement, the power block runs at the required output level, and any excess energy goes to storage. If the storage system is at capacity, the collectors in the field defocus as specified on the Heliostat Field page to reduce the field's thermal output.

By setting the thermal storage dispatch control parameters, you can simulate a dispatch strategy for clear days when storage is at capacity that allows the operator to start the plant earlier in the day to avoid defocusing collectors in the field, for cloudy days that allows the operator to store energy for later use in a time period when the value of power is higher.

Fossil Fill

The **fossil fill fraction** defines the size of the fossil backup as a fraction of the power cycle design gross output. The quantity of fossil backup energy also depends on the **fossil backup boiler LHV efficiency**, **aux heater outlet set temp**, and **fossil dispatch mode parameters** on the Power Cycle page. is added to the input from the solar field and storage system.

Operation of the power block in a given hour with fossil backup is constrained by the **Turb out fraction** you specify for each period, and the **Max turbine over design operation** and **Min turbine operation** from the Power Cycle page. For hours that the added fossil energy is insufficient to meet the **Min turbine operation** requirement, fossil backup is not dispatched. For hours when the combined fossil and solar contribution exceeds the **Turb out fraction** for the hour, the amount of fossil energy dispatched is reduced until the required turbine output is met.

Defining Dispatch Schedules

The storage dispatch schedules determine when each of the six periods apply during weekdays and weekends throughout the year. You can either choose an existing schedule from one of the schedules in the CSP Tower TES dispatch library or define a custom schedule. For information about libraries, see Working with Libraries.

The TES dispatch library only assigns period numbers to the weekday and weekend schedule matrices. The dispatch fractions assigned to each of the six periods are not stored in the library.

To choose a schedule from the library:

1. Click **Dispatch schedule library**.
2. Choose a schedule from the list of four schedules. The schedules are based on time-of-use pricing schedules from four California utilities.
3. Click **OK**.

   You can modify a schedule using the steps described below. Modifying a schedule does not affect the schedule stored in the library.
4. For each of the up to six periods used in the schedule, enter values for the dispatch fractions described above. Use the period number and color to identify the times in the schedule that each period applies.

To specify a weekday or weekend schedule:

1. Assign values as appropriate to the Storage Dispatch, Turbine Output Fraction, Fossil Fill Fraction,

and TOD Factor for each of the up to nine periods.

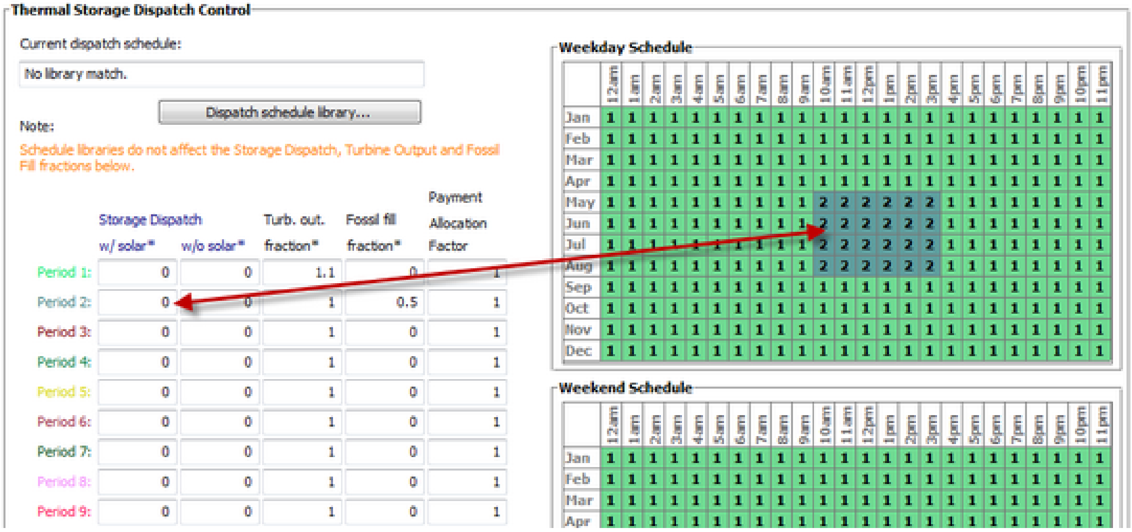
2. Click **Dispatch schedule library**.
3. Choose a **Uniform Dispatch**.
4. Click **OK**.
5. Use your mouse to draw a rectangle in the matrix for the first block of time that applies to period 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

6. Type the number 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

7. SAM shades displays the period number in the squares that make up the rectangle, and shades the rectangle to match the color of the period.



8. Repeat Steps 2-4 for each of the remaining periods that apply to the schedule.

7.3.6 Parasitics

To view the Parasitics page, click **Parasitics** on the main window's navigation menu. Note that for the power tower input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Power Tower System.

The parameters on the Parasitics page describe parasitic electrical loads and other losses in the power tower system.

Page numbers relevant to this section from the Wagner (2008) and Kistler B (1986) references are:

- Kistler 224

The parasitic loss variables are factors that SAM uses to calculate the estimated total parasitic loss and hourly parasitic losses, which are described in more detail below.

SAM calculates two types parasitic loss values. The first is an estimate of the total parasitic losses used to calculate the power block design thermal input, and the second are the hourly values calculated during simulation of the system's performance.

Note. Parasitic losses from components that do not exist in the system should be set to zero.

Parasitic Energy Consumption

Startup Energy of a Single Heliostat, kWe-hr

The electric energy in kilowatt-hours required to move each heliostat into position. Applies during hours when the heliostat is starting up.

Tracking Power for a Single Heliostat, kWe

The electric power in kilowatts required by the tracking mechanism of each heliostat in the field during hours of operation.

Receiver HTF Pump Efficiency

The electro-mechanical efficiency of the receiver heat transfer fluid pump.

Fraction of rated gross power consumed at all times

A fixed electric load applied to all hours of the simulation, expressed as a fraction of rated gross power at design from the Power Cycle page.

Required pumping power for HTF through storage, kJ/kg

A coefficient used to calculate the electric power consumed by pumps to move heat transfer fluid through the storage heat exchanger on both the solar field side and the storage tank side (for cases where a heat exchanger exists, specified on the Thermal Storage page). This coefficient is applied separately to the solar field flow and the tank flow.

Piping Loss Coefficient, Wt/m

Thermal loss per meter of piping. Includes piping throughout the system.

Piping Length Constant, m

The length of hot piping in the system, not including hot piping in the tower. SAM adds the piping length constant value to the tower hot piping length to calculate the total hot piping thermal losses.

Piping Length Multiplier

SAM multiplies this value by the tower height to determine the length of hot piping in the tower for thermal loss calculations.

A multiplier of 2 represents the total length of HTF header piping up and down the tower. A multiplier greater than 2 would account for additional piping between the power block and the base of the tower.

Total Piping Length, m

Length of piping throughout the system: From the receiver to power block, power block to process heat, etc. The piping loss varies with output produced by turbine.

Balance of Plant Parasitic, MWe/MWcap

Losses as a fraction of the power block nameplate capacity that apply in hours when the power block operates.

Cooling Tower Parasitic Power, MWe/MWcap

The cooling tower parasitic losses as a fraction of power block nameplate capacity are electrical losses that occur when the power block operates at part or full load.

7.4 Power Tower Direct Steam

The direct steam power tower consists of the same components and functionality of the molten salt power tower, with two important differences. First, the steam flowing through the tower is both the heat transfer fluid that transfers energy from the receiver and the working fluid of the power cycle (a "direct" system). Secondly, the steam tower is composed of three individual receivers: a boiler, superheater, and reheater; each with a defined role. These differences require additional inputs and changes to the control strategy, which are detailed in this section.

For a general description of the direct steam power tower model, see Overview.

For a description of the solar field optimization process, see Optimization Wizard.

The input pages for the direct steam power tower model are:

- Location and Resource
- Tower System Costs
- Heliostat Field
- Tower and Receiver
- Power Cycle
- Parasitics

7.4.1 Tower Direct Steam Overview

The direct steam power tower is based upon the same concepts as the molten salt power tower: a first-principles energy balance model of the receiver, regression methodology to determine Rankine cycle performance while maintaining flexibility to account for various cycle configurations, and field layout/receiver optimization options. However, the direct steam power tower is characterized by two important differences that result in significant modifications to the molten salt tower model.

1. The steam flowing through the tower is both the heat transfer fluid that transfers energy from the receiver and the working fluid of the power cycle (a "direct" system). In other words, the flow from receiver travels directly through the power block and back to the receiver. This coupling requires that information describing the power cycle such as pressures, feedwater extraction mass flow rates, and the feedwater outlet temperature be known for the direct steam system. Therefore, you have control over additional information detailing the Rankine cycle for the direct steam power tower.
2. The steam tower receiver is composed of three individual receivers: a boiler, superheater and reheater, each with a uniquely defined role. The recirculating boiler accepts feedwater from the power cycle and generates a two-phase (boiling) flow at a user-specified quality. The dry steam from the boiler then passes through a superheater where flux heats the steam to a temperature and pressure that you specify. SAM also models a reheat loop, where steam from the high pressure turbine is redirected through a dedication portion of the receiver and reaches a user-specified target temperature before passing through the remainder of the power cycle.

The configuration of multiple receiver sections on the tower requires a strategy to allocate flux from the field to each of the receivers. The strategy developed for the direct steam power tower assumes that all of the flux from the field can be allocated to any one of the receivers at any time. SAM uses an iterative procedure to solve for the flux distribution on the receiver for each simulation time step. The iterative procedure progresses as follows:

- First, a portion of the total flux is assigned to the boiler and superheater. A fraction of this portion is then assigned to the boiler and the mass flow rate of steam that results in the target outlet quality is calculated.
- The outlet temperature of the superheater is calculated based on the guessed incident flux and the steam conditions. If the calculated temperature does not meet the target, the fraction assigned to the boiler is adjusted.
- Once the superheater outlet temperature is resolved, SAM determines the reheater performance. If the calculated outlet temperature does not match the target, then the portion of total flux assigned to the boiler and superheater is adjusted once again, and the process is repeated until the target reheater outlet temperature is met.

The solar field optimization algorithm is based on the DELSOL3 model developed at Sandia National Laboratories, and described in *A User's Manual for DELSOL3: A Computer Code for Calculating the Optical Performance and Optimal System Design for Solar Thermal Central Receiver Plants*, Kistler (1986), (SAND86-8018) http://www.prod.sandia.gov/cgi-bin/techlib/access-control.pl/1986/868018.pdf (10 MB). The DELSOL software and user's manual is available from Sandia here: http://energy.sandia.gov/?page_id=6530.

For a description of the solar field optimization process, see Optimization Wizard.

You can explore the source code written in FORTRAN for the tower direct steam model in the following folder of your SAM installation folder (c:\SAM\SAM 2014.1.14 by default): C:\exelib\trnsys\source. The files are:

- Heliostat Field: sam_mw_pt_Type221.for
- Tower and Receiver Controller: sam_dsg_controller_Type265.f90
- Tower and Receiver Boiler: sam_dsg_boiler.f90
- Tower and Receiver Superheater: sam_dsg_superheater.f90
- Tower and Receiver Reheater: sam_dsg_reheater.f90
- Power Cycle: sam_mw_pt_TYPE234.f90
- Parasitics: sam_dsg_controller_Type265.f90 / sam_mw_pt_Type228.f90

The input pages for the direct steam power tower model are:

- Location and Resource
- Tower System Costs
- Heliostat Field
- Tower and Receiver
- Power Cycle
- Parasitics

7.4.2 Heliostat Field

The Heliostat Field page displays the variables that specify the position of the heliostats in the solar field along with the heliostat geometry and optical properties. Unlike parabolic trough and dish system designs, which can be based on modular designs of individual components, power tower system designs typically require optimization of the tower height, receiver geometry, and distribution of heliostats around the receiver as a complete system.

Page numbers relevant to this section from the Wagner (2008) and Kistler B (1986) references are:

- Wagner p 10, 23-42, 49
- Kistler p 25-37, 39-47, 74-75

You can define the heliostat field layout in two ways: If you have a field layout in mind, you can enter values by hand. Or, you can use SAM's optimization wizard to determine the optimal layout for you.

Input Variable Reference

Heliostat Parameters

The heliostat properties define the area of a single heliostat mirrored surface, shape of the heliostat, and the boundaries of the solar field area. Note that SAM assumes that each heliostat employs a two-axis drive system with a pivot at the center of the mirrored surface.

Heliostat width, m

The width of the heliostat surface in meters, including the mirrored surface, edge supports and any cutouts or slots.

Heliostat height, m

The height of the heliostat surface in meters, including the mirrored surface, edge supports and any cutouts or slots.

Ratio of reflective area to profile

The fraction of the area defined by the heliostat width and height that actually reflects sunlight. This value determines the ratio of reflective area on each heliostat to the total projected area of the heliostat on a plane normal to the heliostat surface. The ratio accounts for non-reflective area on the heliostat that may cause shading of neighboring heliostats.

Use round heliostats (Dia=W)

Check the box to use round heliostats in place of the standard rectangular shape. For round heliostats, the heliostat diameter is equal to the value of the Heliostat Width variable.

Heliostat area, m²

The area of the heliostat mirrored area. For rectangular heliostats, the area is the product of the heliostat width and height (or the product of the square of half the width and pi for round heliostats) and the ratio of reflective area to heliostat profile.

Total reflective area, m²

Total mirrored area of the heliostat field, equal to the heliostat reflective area multiplied by the number of heliostats. SAM uses the total field area to calculate the site improvements and heliostat costs on the Tower System Costs page.

Solar field land area

The total land area required for the solar field.

Number of heliostats

The total number of individual heliostats in the field. SAM displays the number of heliostats based either on the results of the optimization wizard, or based on the data in the heliostat layout file when the heliostat locations are loaded from a text file.

Derates

Reflectance and soiling

The mirror reflectance input is the solar weighted specular reflectance. The solar-weighted specular reflectance is the fraction of incident solar radiation reflected into a given solid angle about the specular reflection direction. The appropriate choice for the solid angle is that subtended by the receiver as viewed from the point on the mirror surface from which the ray is being reflected. For parabolic troughs, typical values for solar mirrors are 0.923 (4-mm glass), 0.945 (1-mm or laminated glass), 0..906 (silvered polymer), 0.836 (enhanced anodized aluminum), and 0.957 (silvered front surface).

Heliostat availability

An adjustment factor that accounts for reduction in energy output due to downtime of some heliostats in the field for maintenance and repair. A value of 1 means that each heliostat in the field operates whenever sufficient solar energy is available. SAM multiplies the solar field output for each hour by the availability factor.

Image error, radians

A measure of the deviation of the actual heliostat image on the receiver from the expected or ideal image that helps determine the overall shape and distribution of the reflected solar flux on the receiver. This value specifies the total conical error distribution for each heliostat at one standard deviation in radians. SAM applies the value to each heliostat in the field regardless of its distance from the tower. The image error accounts for all error sources, including tracking imprecision, foundation motion, mirror waviness, panel alignment problems, atmospheric refraction and tower sway.

Operation

Stow deploy angle, degrees

Solar elevation angle below which the heliostat field will not operate.

Stow wind speed, m/s

Wind velocity from the weather file at which the heliostats defocus and go into stowed position. At wind speeds above the stow speed, SAM assumes that the heliostats move into stow position to protect the mirror surface and support structure from wind damage. SAM accounts for the parasitic tracking power required to stow the heliostats, and to reposition them when the wind speed falls below the stow speed.

Mirror Washing

SAM reports the water usage of the system in the results based on the mirror washing variables and the power cycle water use determined in the annual performance calculation. The annual water usage is the product of the water usage per wash and 365 (days per year) divided by the washing frequency plus the calculated power cycle usage.

Water usage per wash, L/m²

The volume of water in liters per square meter of solar field aperture area required for periodic mirror washing.

Washes per year

Number of times per year that heliostats mirrors are washed.

Distance to Tower

Min and Max heliostat dist to tower height ratio

The minimum and maximum allowable radial distances expressed as the ratio of minimum and maximum distances between tower and nearest and furthest heliostat to the center of the tower base. Under certain conditions, SAM uses this value to calculate the radial step size. (See radial step size variable description below.)

Land Area

Non-Solar Field Land Area, acres

The land area in acres occupied by the project, not including the heliostat field.

Solar Field Land Area Multiplier

The total solar field land area, including the area occupied by heliostats and space between heliostats, expressed as a multiple of the area occupied by heliostats. The default value is 1.3, which represents a total solar field land area that is 1.3 times the area occupied by heliostats.

Calculated Total Land Area, acres

Land area required for the entire system including the solar field land area.

Total Land Area (acres) = Non-Solar Field Area (acres) + Area of Zones Occupied by Heliostats (m^2) × Solar Field Land Area Multiplier × 0.0002471 (acres/m)

The area of zones occupied by heliostats depends on the field geometry, which is either calculated by the field optimization wizard, or for a rectangular field, depends on the geometry you specify.

The land area appears on the System Costs page, where you can specify land costs in dollars per acre.

Heliostat Field Layout Optimization

When the you are specifying the heliostat field using radial sections, SAM can find the optimal number of heliostats for each section automatically. See Optimization Wizard for more information.

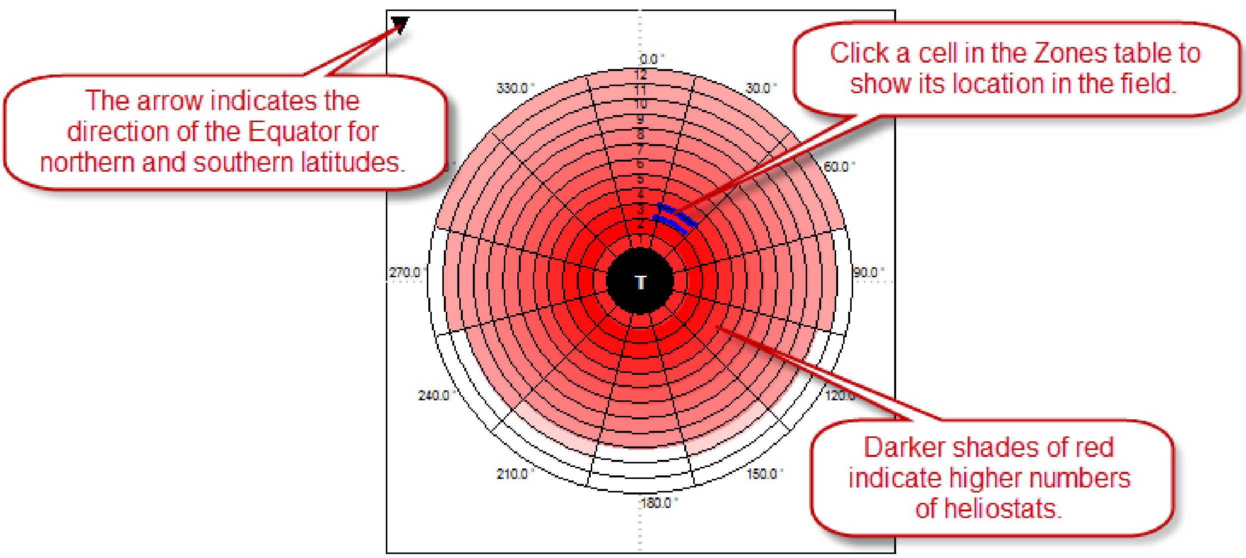
Note. The optimization wizard will not work if you are specifying the solar field using x-y coordinates.

Specifying the Field

SAM allows the heliostat locations in the field to be specified either by a set of rectangular coordinates (x-y) or as a number of heliostats per radial section of the field (number of radial and azimuthal zones).

Radial and Azimuthal Zones

To specify the field as a number of heliostats per radial zone enter the number of radial zones and azimuthal zones to divide the heliostat field into radial zones shown in the field diagram. You can then specify the field manually or automatically. To specify the field manually, either type values in the Number of Heliostats Per Zone table or import the data as a text file. To specify the field automatically, use the optimization wizard to specify a set of optimization parameters and allow SAM to optimize the heliostat field design and calculate the optimal number of heliostats per zone, receiver tower height, receiver height and diameter, and other variables.



The diagram shows that solar field is divided into evenly distributed sections of a circle called zones. The rows of the Zones table specify the radial position if each zone relative to the tower located at the center of the field. The zone closest to the tower is assigned the number one, with each successively farther zone incrementing by one. The columns specify the position of the zone's center in degrees east of due north, where zero is north, 90 degrees is east, 180 degrees is south, and 270 degrees is west. The number of heliostats per zone can be a non-integer value because SAM converts the value to a mirror surface area for each zone that is equivalent to the total mirrored surface of all heliostats in the zone.

Rectangular (x-y) Coordinates

To specify the field as a set of rectangular coordinates, change the value of Azimuthal Zones to 2, and enter the number of heliostats for # of Heliostats. You can then either type the x-y coordinates of each heliostat in the field, or import a text file of x-y coordinates. SAM displays the location of each heliostat on the field diagram. It models the system based on the heliostat locations specified by the set of x-y locations, and based on the values you specify for the tower height, receiver height, receiver diameter, and other input values. This approach is appropriate for predicting the output of a system with a known design. The optimization wizard does not work in the x-y coordinate mode.

Each row specifies the position of an individual heliostat relative to the tower. The first column in the table specifies the x-coordinate along the east-west axis of the field, with negative values indicating positions west of the tower, and positive values indicating positions east of the tower. The second column specifies the y-coordinate along the north-south axis, with positive values indicating positions north of the tower, and negative values indicating positions south of the tower. The tower is assumed to be at 0,0. Note that this convention also applies to systems in the southern hemisphere. In the x-y coordinate mode, SAM requires that the field be symmetric about the north-south axis.

Working with Heliostat Field Files

SAM allows you to use text files to save and load field layout data when you specify the field layout by hand instead of relying on the optimization wizard to calculate the optimal layout.

For radial zone data, each row in the file represents a radial step (distance away from the center of the circle), and each column represents an azimuthal division (distance clockwise around the circle from the zero degree line pointing north), as shown on the sample layout diagram. The first row must contain data for the radial step closest to the center of the field, and subsequent rows should be in consecutive order away from the center. The first column of each row must contain data for the azimuthal division containing the north line at zero degrees, and the second column the next division moving counterclockwise from the first column, and so on. Zones with no heliostats should be indicated by a zero. Each column in the file should be separated by a space, and each row by a new line. For example, a text file with the following contents would describe a field with three radial steps and four azimuthal divisions:

```
9.0 10.0 9.0 10.0
15.5 15.5 15.5 15.5
22.5 18.0 18.5 22.5
```

For rectangular coordinate data, each row represents an individual heliostat position in the field, with the x coordinate in the first column and the y coordinate in the second column. A positive x value is east, and a positive y value is north of the tower. Use negative values for positions west and south of the tower. The heliostat coordinates do not have to be in a particular order in the file. Each column in the file should be separated by a space, and each row by a new line. A file with the following contents would describe a solar field with three heliostats at (x = 0.0, y = 75.0), (x = 7.5, y = 70.0), and (x = 15.0, y = 65.0):

```
0.0 75.0
7.5 70.0
15.0 65.0
```

7.4.3 Tower and Receiver

The Tower and Receiver page displays variables that specify the geometry of the heat collection system. The receiver model uses semi-empirical heat transfer and thermodynamic relationships to determine the thermal performance of the receiver. This allows the model to represent a wide array of geometries without deviating from a hypothetical reference system.

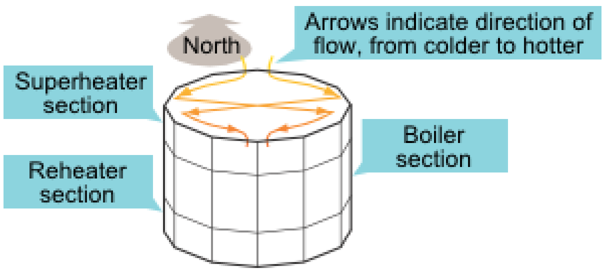
- Wagner (2008) p 43-47, 68-71

The model makes several assumptions about the system geometry for external receivers:

- The receiver consists of a discrete number of panels, in multiples of two.
- Each panel in the receiver consists of a set of parallel tubes in thermal contact that share a common steam header.
- The panel tubing is vertical and the heat transfer fluid flows through each sequential panel in a serpentine pattern (up one panel and down the adjacent panel).
- The number of tubes per panel is a function of the Number of Panels, Receiver Diameter, and Tube Outer Diameter variables.

The steam tower receiver is composed of three receiver sections: a boiler, superheater and reheater. The recirculating boiler accepts feedwater from the power cycle and generates a two-phase (boiling) flow at a user-specified quality. The dry steam from the boiler then passes through a superheater where flux heats the steam to a temperature that you specify. SAM also models a reheat loop, where steam from the high pressure turbine is redirected through a dedicated portion of the receiver and reaches a user-specified target temperature before passing through the remainder of the power cycle.

SAM allows you to choose from two steam flow patterns through the receiver. The following diagram shows Option 1, where steam flows through the receiver from north to south:



The configuration of multiple receiver sections on the tower requires a strategy to allocate flux from the field to each of the receiver sections. The strategy developed for the direct steam power tower employs a simplifying assumption that the flux from the field can be allocated to any one of the receiver sections at any time. SAM uses an iterative procedure to solve for the flux distribution on the receiver for each simulation time step that maintains the boiler outlet quality and steam temperature requirements in the superheater and reheater sections. The iterative procedure progresses as follows:

- First, a portion of the total flux is assigned to the boiler and superheater. A fraction of this portion is then assigned to the boiler and the steam mass flow rate that results in the target outlet quality is calculated.
- The outlet temperature of the superheater is calculated based on the guessed incident flux and the steam conditions exiting the boiler. If the calculated temperature does not meet the target, flux is redistributed between the boiler and superheater until the required steam outlet temperature is achieved.

- Once the superheater outlet temperature is resolved, SAM determines the reheater performance using the remaining un-apportioned flux. If the calculated outlet temperature does not match the target, then the portion of total flux assigned to the boiler and superheater is readjusted, and the process is repeated until the target reheater outlet temperature is met.

Direct Steam Receiver

For analyses involving the optimization wizard to optimize the heliostat field layout, SAM populates several of these variables with optimal values. You can change the values after running the optimization wizard, but results will no longer be for the optimal system.

Receiver diameter, m

Total diameter in meters of the receiver. The distance from center of the receiver to center of a receiver panel. The width of a single panel is the circumference of receiver divided by number of panels.

Receiver height, m

Height in meters of the receiver panels.

Number of groups of two panels

The number of pairs of receiver panels.

Number of panels

Number of vertical panels in the receiver. The number of panels must be divisible by two to accommodate the available flow patterns.

Coating emittance

Average receiver-temperature weighted thermal emittance of coatings on boiler, superheater and reheater tubes. This value is used in the calculation of radiation losses to the surroundings.

Coating Absorptance

Solar-weighted absorptance of coatings on boiler, superheater, and reheater tubes: The fraction of incident radiation absorbed by the receiver in the solar spectrum.

Boiler

Boiler height, m

Height in meters of the boiler section of the receiver.

Maximum boiler flux, kWt/m²

The upper limit of the reflected irradiation from the solar field incident on the boiler at any point. For systems optimized with the wizard, SAM ensures that the optimal receiver size and heliostat positions result in a receiver flux that does not exceed this value.

Outside diameter of boiler tubes, m

The outer diameter in meters of the individual parallel boiler tubes that carry the water/steam through the boiler panels.

Thickness of boiler tubes, m

The thickness in meters of the boiler tube walls.

Boiler tube material

The material of the boiler tubes. Stainless-steel and T-91 steel are available in the current version of SAM. The tubing material properties and geometry are used to calculate the heat transfer behavior of the receiver.

Target boiler output steam quality

The quality (or mass-based vapor fraction) of steam at the boiler exit. The model will ensure that this quality is reached within a convergence tolerance whenever the receiver is operating. Since a recirculating boiler is modeled, only qualities between 0.25 and 0.75 should be evaluated.

Reference boiler efficiency

Estimate of the thermal efficiency of the boiler at design conditions. This value is one input used by the optimization wizard to size the boiler. Note that this value is not used in the annual hourly performance calculation but is only used to help size the boiler during design.

Superheater

Superheater height, m

Height in meters of the superheater section of the receiver.

Maximum superheater flux, kWt/m²

The upper limit of the reflected irradiation from the solar field incident on the superheater at any point. For systems optimized with the wizard, SAM ensures that the optimal receiver size and heliostat positions result in a receiver flux that does not exceed this value.

Outside diameter of superheater tubes, m

The outer diameter in meters of the individual parallel superheater tubes that carry the steam through the superheater panels.

Thickness of superheater tubes, m

The thickness in meters of the superheater tube walls.

Superheater material

The material of the superheater tubes. Stainless-steel and T-91 steel are available in the current version of SAM. The tubing material properties and geometry are used to calculate the heat transfer behavior of the receiver.

Superheater outlet temperature set point, °C

The temperature of the steam at the superheater exit. The model will ensure that this temperature is reached within a convergence tolerance whenever the receiver is operating.

Reference superheater efficiency

Estimate of the thermal efficiency of the superheater at design conditions. This value is one input used by the optimization wizard to size the superheater. Note that this value is not used in the annual hourly performance calculation but is only used to help size the superheater during design.

Reheater

Reheater height, m

Height in meters of the reheater section of the receiver.

Maximum reheater flux, kWt/m²

The upper limit of the reflected irradiation from the solar field incident on the reheater at any point. For systems optimized with the wizard, SAM ensures that the optimal receiver size and heliostat positions result in a receiver flux that does not exceed this value.

Outside diameter of reheater tubes, m

The outer diameter in meters of the individual parallel reheater tubes that carry the steam through the reheater panels.

Thickness of reheater tubes, m

The thickness in meters of the reheater tube walls.

Reheater material

The material of the boiler tubes. Stainless-steel and T-91 steel are available in the current version of SAM.

Reheater outlet temperature set point, °C

The temperature of the steam at the reheater exit. The model will ensure that this temperature is reached within a convergence tolerance whenever the receiver is operating. Note that this value is not used in the annual hourly performance calculation but is only used to help size the reheater during design.

Reference reheater efficiency

Estimate of the thermal efficiency of the reheater at design conditions. This value is one input used by the optimization wizard to size the reheater.

Flow

Flow Pattern

The direction of flow of steam through the receiver. Choose Option 1 if steam flows through the receiver from south to north. Choose Option 2 if the steam flows in the opposite direction, from south to north.

Tower

Tower height, m

The optical height in meters of the tower structure from the heliostat pivot point to the vertical center of the receiver.

Thermal Design and Operation

Solar multiple

The solar multiple represents the ratio of the thermal power produced by the solar field at design conditions to the thermal power required by the power cycle at design. The solar multiple is used by the optimization wizard to determine the heliostat field and receiver geometry that produce the required thermal output. If you modify the solar multiple without running the optimization wizard, the receiver design thermal power will change, but the solar field will not. Consequently, you should modify the solar multiple only during optimization runs or to match a manually entered heliostat field/receiver system design. The optimal solar multiple will typically be higher for molten salt tower systems with thermal storage, though direct steam systems without storage may also have an optimal solar multiple greater than one.

Min fraction of design thermal power

The minimum allowable fraction of the design thermal power transferred to the steam by the receiver.

Receiver design thermal power, MWt

Product of solar multiple and power cycle design thermal power on the Power Cycle page.

Note that this value may not correspond with the realized thermal power output from the receiver during the performance simulation if the user-specified solar multiple deviates from the ratio of power produced by the heliostat field/receiver to the power cycle input requirement. For more information, refer to the

Solar Multiple input reference notes.

Receiver startup delay time, hr

The minimum time in hours required to start the receiver. The receiver starts whenever the radiation incident on the field in the previous hour is zero, and there is sufficient thermal energy in the current hour to meet the thermal design requirement. SAM calculates the start up energy as the product of the available thermal energy, startup delay time, and startup delay energy fraction.

Receiver startup delay energy fraction

Energy required to startup receiver calculated as hours of design point operation.

Heat loss factor

A receiver heat loss adjustment factor that can be used to adjust the receiver thermal losses as appropriate for the receiver design under consideration. The default value is 1, corresponding to no correction of the heat loss correlations implemented in the annual hourly performance model. The calculated receiver heat loss is the sum of convection and radiation losses from the receiver, reported in the hourly results as rec_conv_loss and rec_rad_loss, respectively.

7.4.4 Power Cycle

The steam flowing through the tower is both the heat transfer fluid that transfers energy from the receiver and the working fluid of the power cycle (a "direct" system). In the direct-steam power tower system, the steam flow from the receiver passes directly through the power block and back to the receiver without heat exchange. This coupling requires that information describing the power cycle such as pressures, feedwater extraction mass flow rates, and the feedwater outlet temperature be known for the direct steam system.

The power cycle converts thermal energy to electric energy. The power cycle is assumed to consist of a superheated two-stage turbine with multiple extractions for feedwater heating and a reheat extraction between the high and low pressure turbine stages. The design-point efficiency of this cycle is the value you specify on the Power Cycle page, and SAM models the part-load behavior with normalized performance curves as a function of steam inlet temperature, mass flow rate, and ambient temperature. The ambient temperature correction uses the wet-bulb temperature for wet-cooled systems and hybrid systems and the dry-bulb temperature for dry cooled and hybrid cooled systems.

Page numbers relevant to this section from the Wagner (2011) and Kistler B (1986) references are:

- Wagner 55-63
- Kistler 224

The power cycle page displays variables that specify the design operating conditions for the steam Rankine cycle used to convert thermal energy to electricity.

Plant Design

Design turbine gross output, MWe

The power cycle's design output, not accounting for parasitic losses.

Estimated gross to net conversion Factor

An estimate of the ratio of the electric energy delivered to the grid to the power cycle's gross output. SAM uses the factor to calculate the power cycle's nameplate capacity for capacity-related calculations, including the estimated total cost per net capacity value on the System Costs page, and the capacity factor reported in the results.

Net nameplate capacity, MWe

The power cycle's nameplate capacity, calculated as the product of the design gross output and estimated gross to net conversion factor.

Net Nameplate Capacity (MWe) = Design Gross Output (MWe) × Estimated Gross to Net Conversion Factor

Rated cycle efficiency

The thermal to electric conversion efficiency of the power cycle under design conditions.

Design thermal input power, MWt

The turbine's design thermal input. It is the thermal energy required at the power block inlet for it to operate at its design point, as defined by the value of the nameplate electric capacity and an estimate of the parasitic losses: Design thermal power = nameplate electric capacity + total parasitic loss estimate. (See the Parasitics page for a description of the total parasitic loss estimate.)

High pressure turbine inlet pressure, bar

The inlet pressure of the high pressure turbine at design. This is one of the values necessary to define the cycle at design. Current steam properties are limited to 190 bar, so this pressure should be set lower than 190 bar so that the property calculations do not fail at higher pressures calculated upstream of the turbine. The simulation may stop or produce warnings if the property routing encounters pressures greater than 190 bar.

High pressure turbine outlet pressure, bar

The outlet pressure of the high pressure turbine at design. This is another value necessary to define the cycle at design.

Design reheat mass flow rate fraction

The fraction of steam mass flow rate that exits the high pressure turbine and enters the reheater. The remaining flow is transferred to the feedwater heaters for use in preheating.

Fossil backup boiler LHV efficiency

The backup boiler's lower heating value efficiency, used to calculate the quantity of gas required by the boiler.

Steam cycle blowdown fraction

The fraction of the steam mass flow rate in the power cycle that is extracted and replaced by fresh water. This fraction is multiplied by the steam mass flow rate in the power cycle for each hour of plant operation to determine the total required quantity of power cycle makeup water. The blowdown fraction accounts for water use related directly to replacement of the steam working fluid. The default value of 0.013 for the wet-cooled case represents makeup due to blowdown quench and steam cycle makeup during operation and startup. A value of 0.016 is appropriate for dry-cooled systems to account for additional wet-surface air cooling for critical Rankine cycle components.

Plant Cooling Mode

Condenser type

Choose either an air-cooled condenser (dry cooling), evaporative cooling (wet cooling), or hybrid cooling system.

In hybrid cooling a wet-cooling system and dry-cooling share the heat rejection load. Although there are many possible theoretical configurations of hybrid cooling systems, SAM only allows a parallel cooling option.

Ambient temp at design, ºC

The ambient temperature at which the power cycle operates at its design-point-rated cycle conversion efficiency. For the air-cooled condenser option, use a dry bulb ambient temperature value. For the evaporative condenser, use the wet bulb temperature.

Reference condenser water dT, ºC

For the evaporative type only. The temperature rise of the cooling water across the condenser under design conditions, used to calculate the cooling water mass flow rate at design, and the steam condensing temperature.

Approach temperature, ºC

For the evaporative type only. The temperature difference between the circulating water at the condenser inlet and the wet bulb ambient temperature, used with the ref. condenser water dT value to determine the condenser saturation temperature and thus the turbine back pressure.

ITD at design point , ºC

For the air-cooled type only. Initial temperature difference (ITD), difference between the temperature of steam at the turbine outlet (condenser inlet) and the ambient dry-bulb temperature.

Note. When you adjust the ITD, you are telling the model the conditions under which the system will achieve the thermal efficiency that you've specified. If you increase the ITD, you should also modify the thermal efficiency (and/or the design ambient temperature) to accurately describe the design-point behavior of the system. The off-design penalty in the modified system will follow once the parameters are corrected.

Condenser pressure ratio

For the air-cooled type only. The pressure-drop ratio across the air-cooled condenser heat exchanger, used to calculate the pressure drop across the condenser and the corresponding parasitic power required to maintain the air flow rate.

Minimum condenser pressure

The minimum condenser pressure in inches if mercury prevents the condenser pressure from dropping below the level you specify. In a physical system, allowing the pressure to drop below a certain point can result in physical damage to the system. For evaporative (wet cooling), the default value is 1.25 inches of mercury. For air-cooled (dry cooling), the default is 2 inches of mercury. For hybrid systems, you can use the dry-cooling value of 2 inches of mercury.

Cooling system part load levels

The cooling system part load levels tells the heat rejection system model how many discrete operating points there are. A value of 2 means that the system can run at either 100% or 50% rejection. A value of three means rejection operating points of 100% 66% 33%. The part load levels determine how the heat rejection operates under part load conditions when the heat load is less than full load. The default value is 2, and recommended range is between 2 and 10. The value must be an integer.

Operation

Low resource standby period, hours

During periods of insufficient flow from the heat source due to low thermal resource, the power block may enter standby mode. In standby mode, the cycle can restart quickly without the startup period required by a cold start. The standby period is the maximum number of hours allowed for standby mode.

This option is only available for systems with thermal storage. Default is 2 hours.

Fraction of thermal power needed for standby

The fraction of the turbine's design thermal input required from storage to keep the power cycle in standby mode. This thermal energy is not converted into electric power. Default is 0.2.

Startup time, hours

The time in hours that the system consumes energy at the startup fraction before it begins producing electricity. If the startup fraction is zero, the system will operate at the design capacity over the startup time. Default is 0.5 hours.

Fraction of thermal power needed for startup

The fraction of the turbine's design thermal input required by the system during startup. This thermal energy is not converted to electric power. Default is 0.75.

Minimum operation fraction

The fraction of the nameplate electric capacity below which the power block does not generate electricity. Whenever the power block output is below the minimum load and thermal energy is available from the solar field, the field is defocused. For systems with storage, solar field energy is delivered to storage until storage is full. Default is 0.25.

Max over design operation fraction

The maximum allowable power block output as a fraction of the electric nameplate capacity. Whenever storage is not available and the solar resource exceeds the design value of 950 W/m², some heliostats in the solar field are defocused to limit the power block output to the maximum load. Default is 1.05.

Fossil dispatch mode

SAM operates the fossil backup system based on the option you choose for Fossil dispatch mode:

Minimum backup level

In the Minimum Backup Level mode, whenever the fossil fill fraction is greater than zero for any dispatch period, the system is considered to include a fossil burner that heats the HTF before it is delivered to the power cycle.

In this mode, the fossil fill fraction defines the fossil backup as a function of the thermal energy from the solar field in a given hour and the design turbine gross output.

For example, for an hour with a fossil fill fraction of 1.0 when solar energy delivered to the power cycle is less than that needed to run at the power cycle design gross output, the backup heater would supply enough energy to "fill" the missing heat, and the power cycle would operate at the design gross output. If, in that scenario, solar energy (from either the field or storage system) is driving the power cycle at full load, the fossil backup would not operate. For a fossil fill fraction of 0.75, the heater would only be fired when solar output drops below 75% of the power cycle's design gross output.

Supplemental operation

In the Supplemental Operation mode, SAM assumes a fossil backup system of a fixed maximum capacity, for example, capable of supplying 10 MW of thermal energy to the HTF.

The fossil fill fraction defines the size of the fossil backup as a fraction of the power cycle design gross output and this energy is added to the input from the solar field and storage system.

Operation of the power cycle in a given hour is constrained by the **Max turbine over design operation fraction** and **Minimum operation fraction**. For hours that the added fossil energy is insufficient to meet the minimum requirement, fossil backup is not dispatched.

SAM includes the cost of fuel for the backup system in the levelized cost of energy and other metrics reported in the results, and reports the energy equivalent of the hourly fuel consumption in the time series simulation results. The cost of fuel for the backup system is defined on the Tower System Costs page.

Dispatch Control

The dispatch control variables each have six values, one for each of six possible dispatch periods.

Hybrid Cooling Dispatch

When you choose Hybrid as the condenser type, the hybrid dispatch table specifies how much of the cooling load should be handled by the wet-cooling system for each of 6 periods in the year. The periods are specified in the matrices at the bottom of the Power Cycle page. Each value in the table is a fraction of the design cooling load. For example, if you want 60% of heat rejection load to go to wet cooling in Period 1, type 0.6 for Period 1. Directing part of the heat rejection load to the wet cooling system reduces the total condenser temperature and improves performance, but increases the water requirement. SAM sizes the wet-cooling system to match the maximum fraction that you specify in the hybrid dispatch table, and sizes the air-cooling system to meet the full cooling load.

Fossil Fill Fraction

Determines how much energy the backup boiler delivers during hours when there is insufficient energy from the solar field to drive the power cycle at its design output capacity. A value of one for a given dispatch period ensures that the power cycle operates at its design output for all hours in the period: The boiler "fills in" the energy not delivered by the solar field or storage system. For a fossil fill fraction less than one, the boiler supplies enough energy to drive the power cycle at a fraction of its design point. To define a system with no fossil backup, use a value of zero for all six dispatch periods. See Storage and Fossil Backup Dispatch Controls for details.

TOD Factor

The time-of-delivery (TOD) factors allow you to specify a set of TOD power price factors to model time-dependent pricing for projects with one of the Utility Financing options.

The TOD factors are a set of multipliers that SAM uses to adjust the PPA price based on time of day and month of year for utility projects. The TOD factors work in conjunction with the assumptions on the Financing page.

Note. For utility projects with no TOD factors, set the value for all periods to one.

For the CSP models, although the TOD power price factors are financial model inputs, they are on the Storage page because it includes other time-dependent variables, and there may be a relationship between the dispatch factors and the TOD power price factors. For PV and other technology models, the TOD power price factors are on a separate Time of Delivery Factors input page. For a description of how to specify the TOD power price factors for all technology models, see Time of Delivery Factors.

For a description of TOD-related simulation results, see PPA Revenue with TOD Factors.

Dispatch Schedules

The dispatch schedules determine when each of the six periods apply during weekdays and weekends throughout the year.

To specify a weekday or weekend schedule:

1. Assign values as appropriate to the Storage Dispatch, Turbine Output Fraction, Fossil Fill Fraction,

and TOD Factor for each of the up to nine periods.

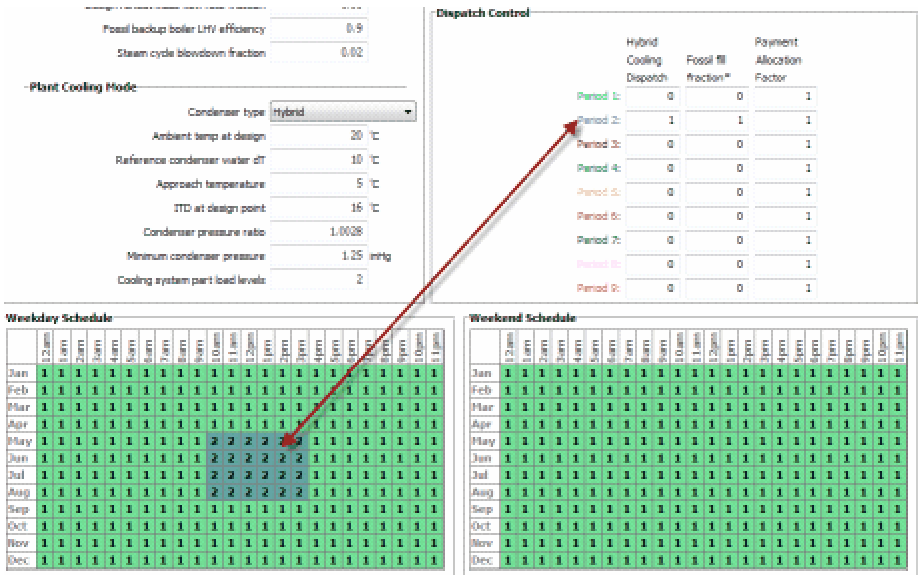
2. Use your mouse to draw a rectangle in the matrix for the first block of time that applies to period 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

3. Type the number 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

4. SAM displays the period number in the squares that make up the rectangle, and shades the rectangle to match the color of the period.



5. Repeat Steps 2-4 for each of the remaining periods that apply to the schedule for both weekdays and weekends.

Note. SAM assumes that the first simulation time step is on a Monday (in the hour ending at 1 a.m.), and that weekends are Saturday and Sunday.

7.4.5 Parasitics

The parameters on the Parasitics page describe parasitic electrical loads and other losses in the power tower system.

Page numbers relevant to this section from the Kistler B (1986) reference is:

- Kistler 224

The parasitic loss variables are factors that SAM uses to calculate the estimated total parasitic loss and hourly parasitic losses, which are described in more detail below.

SAM calculates two types parasitic loss values. The first is an estimate of the total parasitic losses used to calculate the power block design thermal input, and the second are the hourly values calculated during simulation of the system's performance.

Note. Parasitic losses from components that do not exist in the system should be set to zero.

Parasitic Energy Consumption

Startup energy of a single heliostat, kWe-hr

The electric energy in kilowatt-hours required to move each heliostat into position. Applies during hours when the heliostat is starting up.

Tracking power for a single heliostat, kWe

The electric power in kilowatts required by the tracking mechanism of each heliostat in the field during hours of operation.

Feedwater to boiler pump efficiency

The electro-mechanical efficiency of the pump.

Fraction of rated gross power consumed at all times

The fraction of design-point gross power output from the power cycle that is used for parasitic losses associated with facility operation, HVAC, control, lighting, etc.

Piping loss coefficient, Wt/m

Thermal loss per meter of piping as calculated on the Parasitics page. The Total piping length is multiplied by the Piping loss coefficient to determine the thermal losses from piping that are incurred during solar field operation.

Piping length constant, m

A constant piping length independent of the tower height that contributes to the Total piping length value.

Piping length multiplier

A value that multiplies the tower height from the Tower and Receiver page to help determine the Total piping length for thermal losses. The multiplier only applies to the tower height and does not multiply the Piping length constant on the Parasitics page.

Total piping length, m

Length of piping throughout the system: From the receiver to power block, power block to process heat, etc. The piping loss varies with output produced by turbine. The Total piping length is calculated as follows:

$$L_{p,tot} = H_{tower} \cdot F_{p,mult} + L_{p,const}$$

where H_{Tower} is the tower height, $F_{p,mult}$ is the piping length multiplier, and $L_{p,const}$ is the piping length constant.

Balance of plant parasitic, MWe/MWcap

Losses as a fraction of the power cycle electrical power output that apply in hours when the power block operates.

Aux heater, boiler parasitic, MWe/MWcap

Parasitic power consumption incurred during operation of the backup fossil boiler, as a function of thermal power production of the fossil system. This parasitic is only applicable for systems with active fossil backup, and applies during hours in which the fossil system produces thermal power.

7.5 Linear Fresnel

The Linear Fresnel model predicts the performance of a direct-steam generation (DSG) plant that produces superheated steam at temperature and pressure settings that you specify. The model is designed to allow several technology configurations and characterization options that allow flexible and accurate performance analysis.

For an overview of the model see Overview.

The input pages for the linear Fresnel model are:

- Location and Resource
- Linear Fresnel System Costs
- Solar Field
- Collector and Receiver
- Power Cycle
- Parasitics

7.5.1 Linear Fresnel Overview

The Linear Fresnel model predicts the performance of a direct-steam generation (DSG) plant that produces superheated steam at temperature and pressure settings that you specify. The model is designed to allow several technology configurations and characterization options that allow flexible and accurate performance analysis.

The solar field can be configured with an adjustable number of modules for the boiler and superheater sections, and the modules can use different geometry and optical performance input data depending on whether they are part of the boiler or superheater sections. The model allows you to specify whether the solar field uses a recirculated boiler or a once-through design. SAM models the steam mass flow, temperature, pressure, enthalpy, and quality throughout the field and uses this information to predict thermal losses, pressure drops, and transient effects for each hour of the year.

Several options are available for modeling the performance of the solar field. Collector optical performance can be specified using incidence angle modifier equations in the transversal and longitudinal directions, or an optical efficiency table can provide the optical efficiency as a function of either solar position or collector incidence angles. The Linear Fresnel model allows you to specify thermal loss relationships either using a set of polynomial equations or with a detailed evacuated tube receiver model.

The Linear Fresnel tool models all major subsystems associated with direct steam systems, including the solar field, optional auxiliary fossil backup system, the steam Rankine power cycle, heat rejection system, feedwater pumps, and plant control system. Output from the model includes financial metrics as well as detailed performance data covering temperature, pressure, mass flow, thermal energy flow, water use, parasitic consumption, turbine power output, and many other relevant values.

The linear Fresnel model can also be used for compact linear Fresnel reflector (CLFR) systems by using the appropriate coefficients with the polynomial heat loss model for the receiver geometry and heat loss parameters on the Collector and Receiver page.

You can explore the source code written in FORTRAN for the linear Fresnel model in the following folder of your SAM installation folder (c:\SAM\SAM 2014.1.14 by default): C:\exelib\trnsys\source. The files are:

- Solar Field: sam_mw_lf_Type261_steam.f90
- Collector and Receiver: sam_mw_lf_Type261_steam.f90
- Power Cycle: sam_mw_pt_TYPE234.f90
- Parasitics: sam_mw_lf_Type261_steam.f90

The input pages for the linear Fresnel model are:

- Location and Resource
- Linear Fresnel System Costs

- Solar Field
- Collector and Receiver
- Power Cycle
- Parasitics

7.5.2 Solar Field

Contents

- Input Variable Reference describes the input variables and options on the Solar Field page.
- Sizing the Solar Field describes how to choose between Option 1 and Option 2, choose a field layout, choose an irradiation at design value, and optimize the solar multiple for systems with and without storage.

Input Variable Reference

Solar Field Parameters

Option 1 and Option 2

For Option 1 (solar multiple mode), SAM calculates the total required aperture and number of loops based on the value you enter for the solar multiple. For option 2 (field aperture mode), SAM calculates the solar multiple based on the field aperture value you enter. Note that SAM does not use the value that appears dimmed for the inactive option. See Sizing the Solar Field for details.

Solar Multiple

The field aperture area expressed as a multiple of the aperture area required to operate the power cycle at its design capacity. See Sizing the Solar Field for details.

Design point irradiation, W/m²

The design point direct normal radiation value, used in solar multiple mode to calculate the aperture area required to drive the power cycle at its design capacity. Also used to calculate the design mass flow rate of the heat transfer fluid for header pipe sizing. See Sizing the Solar Field for details.

Design point ambient temperature, °C

The reference ambient temperature for the solar field, used as a basis for calculating thermal losses from the receivers and piping. Note that this value is not used as a reference for receiver thermal losses if the evacuated tube receiver option is selected on the Collector and Receiver page.

Loop flow configuration

The loop flow configuration determines whether the boiler is configured as once-through or recirculated. In the once-through design, subcooled feedwater from the power cycle outlet enters the solar field collector loop, is boiled to steam as it passes through the loop, and exits to the hot header as superheated steam.

In the recirculated boiler design, a portion of the collectors in the loop are dedicated to boiling the subcooled feedwater, but the boiler mass flow rate is controlled such that the boiling mixture exits the boiler section with a vapor fraction (quality) equal to the value that you specify in the Boiler outlet steam quality input on the Solar Field page. The liquid fraction is extracted and recirculated to the inlet of the solar field loop where it mixes with the subcooled liquid from the power cycle outlet. The saturated steam at the outlet of the boiler section does not recirculate, but instead passes into the dedicated superheater section where it continues to increase in temperature before entering the power cycle.

The most common configuration for existing Linear Fresnel plants is the recirculated boiler design, though developments in the technology show the once-through design to be promising. Both options are included in this model for comparative purposes.

Superheater has unique geometry

SAM allows you to select unique geometry for the superheater and boiler sections. If this option is selected, the boiler modules will inherit the geometry defined on the Collector and Receiver page under the Linear Fresnel Boiler Geometry option in the dropdown menu near the top of the page. Likewise, the superheater section modules will inherit geometry from the inputs corresponding to the Linear Fresnel Superheater Geometry in the dropdown menu. Note that the inputs and options for the boiler and superheater are identical by default, and changes that you wish to apply must be applied to both sets separately.

If the boiler and superheater sections have consistent geometry, then the inputs corresponding to the Linear Fresnel Boiler Geometry option are applied to both the boiler and superheater sections.

Number of modules in boiler section

The number of boiler units in series in a single loop, each with geometry as defined on the Collector and Receiver page under the Linear Fresnel Boiler Geometry dropdown option.

Number of modules in superheater section

The number of superheater units in series in a single loop, each with geometry as defined on the Collector and Receiver page. If the superheater has unique geometry (as indicated by the checkbox on the Solar Field page, see above), each unit will have geometry corresponding to the Linear Fresnel Superheater Geometry option in the dropdown on the Collector and Receiver page, otherwise the superheater units will have geometry as defined under the Linear Fresnel Boiler Geometry dropdown option.

Note. Take special care in selecting the number of boiler and superheater sections. The steam conditions at the outlet of the solar field depend on the ratio between the heat absorbed by the boiler and the superheater. As the heat absorbed in the superheater sections increases relative to the boiler sections, the outlet steam temperature will also increase beyond the design point. Consequently, the number of superheater modules should correspond to the desired thermal input in addition to the saturated steam produced by the boiler.

Field pump efficiency

The isentropic efficiency of the feedwater and recirculation pump (if applicable) in the solar field. The total work required to propel the feedwater is divided by this efficiency value to give the electrical parasitic pumping requirement.

Collector azimuth angle (degrees)

The azimuth angle of all collectors in the field, where zero degrees is pointing toward the equator, equivalent to a north-south axis. West is 90 degrees, and east is -90 degrees. SAM assumes that the collectors are oriented 90 degrees east of the azimuth angle in the morning and track the daily movement of the sun from east to west.

The collector azimuth angle variable is not active with the **Solar position table option** on the Collector and Receiver page. The variable is only active with either the two incidence angle options for specifying the solar field.

Thermal inertia per unit of solar field

The amount of energy required to increase the working temperature of the solar field, per unit aperture area of the solar field. The thermal inertia term is used to model the startup and shutdown transient behavior of the solar field. During startup, the thermal energy produced by the solar field is reduced according to the energy that goes into heating the working fluid, receiver components, piping, fittings, and insulation. This input captures all of those aspects of transient startup in the solar field.

Steam Conditions at Design

This set of inputs defines the design-point operating conditions of the steam in the solar field. The field inlet and outlet temperatures, the pressure constraints, and the boiler outlet quality (if applicable) are used to calculate the enthalpy of steam during the annual performance calculation at each collector module in the loop.

Field inlet temperature, °C

The estimated temperature of feedwater from the power cycle at the inlet of the solar field. This value is used to calculate estimated thermal losses from the solar field at design, and is not directly used in calculating the hourly performance for the annual simulation. The field inlet temperature is calculated during performance runs based on the power cycle conversion efficiency and the steam temperature at the inlet of the power cycle.

Field outlet temperature, °C

The estimated design-point steam outlet temperature from the solar field. The actual field outlet temperature is calculated in the performance runs based on the Loop flow configuration (once-through or recirculated boiler), the boiler outlet quality (for recirculated designs), collector performance, and flow rate constraints. The actual field outlet temperature during performance calculations is highly sensitive to the ratio of superheater to boiler aperture area, and consequently, the Field outlet temperature that you specify may differ substantially from the actual outlet temperature if care is not taken in selecting the correct number of superheater modules in the recirculated boiler design. Refer to the documentation on the number of boiler/superheater modules for more information.

Boiler outlet steam quality

For the recirculated boiler configuration, the boiler outlet steam quality is used to calculate the mass flow rate of steam in the boiler section. This value represents the fraction of fluid exiting the boiler section that is in vapor phase. The balance of the unevaporated fluid recirculates to the inlet of the solar field and is mixed with the subcooled feedwater from the power cycle outlet.

This value is not used for the once-through Loop flow configuration.

Turbine inlet pressure

The steam pressure at the inlet of the turbine at design conditions. The actual steam pressure during the performance calculations will vary as a function of the steam mass flow rate into the power cycle. The minimum steam pressure is limited to 50% of the design-point rating. Note that the steam mass flow rate into the power cycle may differ from the steam mass flow rate in the solar field if auxiliary fossil backup is used.

Cold header pressure drop fraction

The fractional pressure drop across the cold header section of the solar field at design. The absolute pressure drop at design is equal to the fractional drop times the rated turbine inlet pressure.

Boiler pressure drop fraction

The fractional pressure drop across the boiler section of the solar field at design. The absolute pressure drop at design is equal to the fractional drop times the rated turbine inlet pressure.

Pressure drop fraction between boiler and superheater

The fractional pressure drop across any piping or steam separation equipment between the boiler and superheater sections at design. The absolute pressure drop at design is equal to the fractional drop times the rated turbine inlet pressure.

Design point pressure drop across the superheater fraction

The fractional pressure drop across the superheater section of the solar field at design. The absolute pressure drop at design is equal to the fractional drop times the rated turbine inlet pressure.

Average design point hot header pressure drop fraction

The fractional pressure drop across the hot header section of the solar field at design. The absolute pressure drop at design is equal to the fractional drop times the rated turbine inlet pressure.

Total solar field pressure drop

The total calculated solar field pressure drop at design. The calculated value is based on a sum of the fractional pressure drops from individual solar field subsystems and is multiplied by the rated turbine pressure at design.

$$\Delta P_{sf,design} = P_{turbine,des} \cdot \left(1 + \mathrm{F}_{\Delta \mathrm{P,hdr,cold}} + \mathrm{F}_{\Delta \mathrm{P,boiler}} + \mathrm{F}_{\Delta \mathrm{P,separater}} + \mathrm{F}_{\Delta \mathrm{P,sh}} + \mathrm{F}_{\Delta \mathrm{P,hdr,hot}}\right)$$

Note that the pressure at the inlet of the solar field is equal to the pressure at the inlet of the turbine plus the total pressure drop across the solar field. You should choose a turbine design-point pressure to maintain operable steam pressures at the solar field inlet.

The steam property algorithms currently used in the SAM performance runs limit the maximum steam pressure to 190 bar, and values exceeding this limit will be reset during the simulation. This limit has been known to cause convergence issues in cases where design-point pressures are too high or where the solar field is designed to frequently operate with mass flow rates significantly higher than the design-point flow rate on which the pressure drop relationship is based.

Design Point

Single loop aperture, m²

This calculated value indicates the total reflective aperture area of the collectors in a single loop. The value is calculated by multiplying the number of nodes in the boiler and superheater sections by their corresponding reflective aperture area on the Collector and Receiver page. The total aperture area calculation is as follows:

$$A_{loop} = A_{module,boil} \cdot N_{module,boil} + A_{module,sh} \cdot N_{module,sh}$$

Loop optical efficiency

The total loop optical efficiency at design, where the solar position is normal to the collector aperture. The efficiency is the weighted product of the boiler and superheater sections, if applicable.

Loop thermal efficiency

The estimated thermal efficiency at design conditions corresponding to the input selections on the Collector and Receiver page. If the Polynomial fit heat loss model is used, the polynomial equation for temperature-based heat loss is evaluated at the average design-point solar field temperature, where that temperature is equal to the average of the outlet and inlet solar field temperatures on the Solar Field page.

$$\overline{T_{sf}} = \frac{T_{field,out} - T_{field,in}}{2}$$

If the Evacuated tube heat loss model is used, Solar Advisor estimates thermal efficiency based on the user-specified Estimated avg. heat loss and Variant weighting fraction values on the Collector and Receiver page.

Note that the design-point thermal efficiency value is used only to size the solar field aperture area and is not part of the annual performance calculation.

Piping thermal efficiency

The estimated non-collector piping thermal efficiency at design. This value is calculated based on the Piping thermal loss coefficient on the Parasitics page. The estimated efficiency is equal to the compliment of the product of the average solar field operating temperature at design and the heat loss coefficient divided by the design-point solar irradiation.

$$\eta_{piping} = 1 - \frac{\overline{T_{sf}} \cdot F_{hl,coef}}{I_{bn,design}}$$

Total loop conversion efficiency

The total estimated loop conversion efficiency at design, including collector optical performance, receiver thermal losses, and piping thermal losses. This value is used to size the solar field aperture area given a solar multiple and required power cycle thermal input.

Total required aperture, SM=1

The calculated aperture area that provides a thermal output from the solar field that exactly matches the power cycle design-point thermal input (i.e. a solar multiple of 1). This value is used to calculate the corresponding number of loops at a solar multiple of 1.

Required number of loops, SM=1

The number of loops that fulfills the thermal output requirement of the solar field at a solar multiple of 1.

Actual number of loops

The number of loops in the solar field that produces a thermal output at design equal to the power cycle thermal input rating times the solar multiple.

Actual aperture

The actual aperture area is a calculated value equal to the product of the actual number of loops and the reflective aperture area of a single loop, as calculated above.

Actual solar multiple

The actual solar multiple is calculated using the thermal power produced at design with an aperture area equal to the Actual aperture calculated value, the design-point ambient and irradiation conditions, and the thermal power requirement of the power cycle.

The actual solar multiple may differ from the user-specified input value if the sum of the thermal output provided by the integer number of loops matches the product of the solar multiple (user input) and the power cycle thermal requirement.

Field thermal output

Thermal energy output from the solar field at design conditions. This value is calculated based on the actual aperture area of the field and the estimated loop conversion efficiency at design.

$$\dot{Q}_{sf,design} = I_{bn,des} \cdot \eta_{loop,total} \cdot A_{sf,total} \cdot \frac{1\ [MWt]}{1e6\ [Wt]}$$

Land Area

Solar Field Land Area (m²)

The actual aperture area converted from square meters to acres:

Solar Field Area (acres) = Actual Aperture (m²) × Row Spacing (m) / Maximum SCA Width (m) × 0.0002471 (acres/m²)

The maximum SCA width is the aperture width of SCA with the widest aperture in the field, as specified in the loop configuration and on the Collectors (SCA) page.

Non-Solar Field Land Area Multiplier

Land area required for the system excluding the solar field land area, expressed as a fraction of the solar field aperture area. A value of one would result in a total land area equal to the total aperture area. The default value is 1.4.

Total Land Area (acres)

Land area required for the entire system including the solar field land area

Total Land Area (acres) = Solar Field Area (acres) × (1 + Non-Solar Field Land Area Multiplier)

The land area appears on the System Costs page, where you can specify land costs in dollars per acre.

Mirror Washing

SAM reports the water usage of the system in the results based on the mirror washing variables. The annual water usage is the product of the water usage per wash and 365 (days per year) divided by the washing frequency.

Water usage per wash

The volume of water in liters per square meter of solar field aperture area required for periodic mirror washing.

Washing frequency

The number of days between washing.

Field Control

Min single loop flow rate, kg/s

The minimum allowable steam flow rate in a single loop of the solar field. During night-time or low-insolation operation, the field will recirculate at a mass flow rate equal to this value. The minimum solar field mass flow rate is equal to the Min single loop flow rate times the actual number of loops in the field.

Freeze protection temperature, °C

The temperature below which auxiliary fossil backup heat is supplied to the solar field to prevent water from freezing in the equipment. You should set this value such that a reasonable margin exists between activation of the electric heat trace freeze protection equipment and the actual freezing point of water.

Stow wind speed, m/s

The maximum allowable wind velocity before the collectors defocus and enter safety stow position. The solar field cannot produce thermal energy during time steps in which the ambient wind velocity exceeds this limit.

Solar elevation for collector nighttime stow, deg

The solar elevation angle (above the horizon) that sets the operational limit of the collector field in the evening hours. When the solar elevation angle falls below this value, the collector field will cease operation.

Solar elevation for collector morning deploy, deg

The solar elevation angel (above the horizon) that sets the operational limit of the collector field in the morning hours. When the solar elevation angle rises above this value, the collector field will begin operation.

Sizing the Solar Field

Sizing the solar field of a parabolic trough system in SAM involves determining the optimal solar field aperture area for a system at a given location. In general, increasing the solar field area increases the system's electric output, thereby reducing the project's LCOE. However, during times there is enough solar resource, too large of a field will produce more thermal energy than the power block and other system components can handle. Also, as the solar field size increases beyond a certain point, the higher installation and operating costs outweigh the benefit of the higher output.

An optimal solar field area should:

- Maximize the amount of time in a year that the field generates sufficient thermal energy to drive the power block at its rated capacity.
- Minimize installation and operating costs.
- Use thermal energy storage and fossil backup equipment efficiently and cost effectively.

The problem of choosing an optimal solar field area involves analyzing the tradeoff between a larger solar field that maximizes the system's electrical output and project revenue, and a smaller field that minimizes installation and operating costs.

The levelized cost of energy (LCOE) is a useful metric for optimizing the solar field size because it includes the amount of electricity generated by the system, the project installation costs, and the cost of operating and maintaining the system over its life. Optimizing the solar field involves finding the solar field aperture area that results in the lowest LCOE. For systems with thermal energy storage systems, the optimization involves finding the combination of field area and storage capacity that results in the lowest LCOE.

Option 1 and Option 2

SAM provides two options for specifying the solar field aperture area: Option 1 (solar multiple) allows you to specify the solar field area as a multiple of the power block's rated capacity (design gross output), and Option 2 (field aperture) allows you to specify the solar field aperture area as an explicit value in square meters.

- Option 1: You specify a solar multiple, and SAM calculates the solar field aperture area required to meet power block rated capacity.
- Option 2: You specify the aperture area independently of the power block's rated capacity.

If your analysis involves a known solar field area, you should use Option 2 to specify the solar field aperture area explicitly.

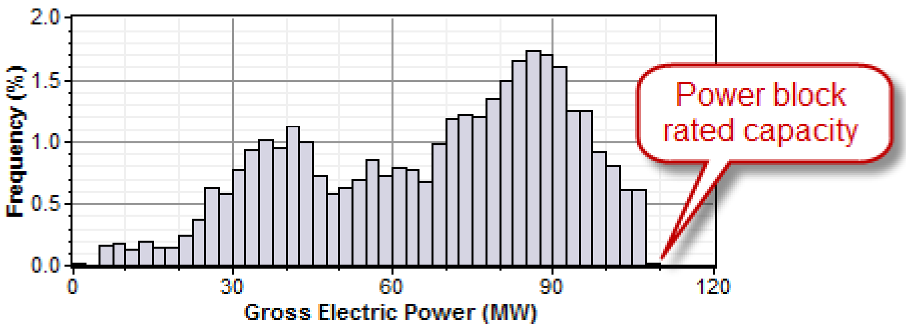
If your analysis involves optimizing the solar field area for a specific location, or choosing an optimal combination of solar field aperture area and thermal energy storage capacity, then you should choose Option 1, and follow the procedure described below to size the field.

Solar Multiple

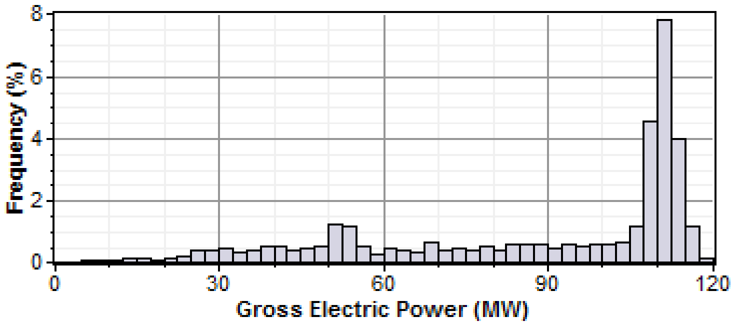
The solar multiple makes it possible to represent the solar field aperture area as a multiple of the power block rated capacity. A solar multiple of one (SM=1) represents the solar field aperture area that, when exposed to solar radiation equal to the design radiation value (irradiation at design), generates the quantity of thermal energy required to drive the power block at its rated capacity (design gross output), accounting for thermal and optical losses.

Because at any given location the number of hours in a year that the actual solar resource is equal to the design radiation value is likely to be small, a solar field with SM=1 will rarely drive the power block at its rated capacity. Increasing the solar multiple (SM>1) results in a solar field that operates at its design point for more hours of the year and generates more electricity.

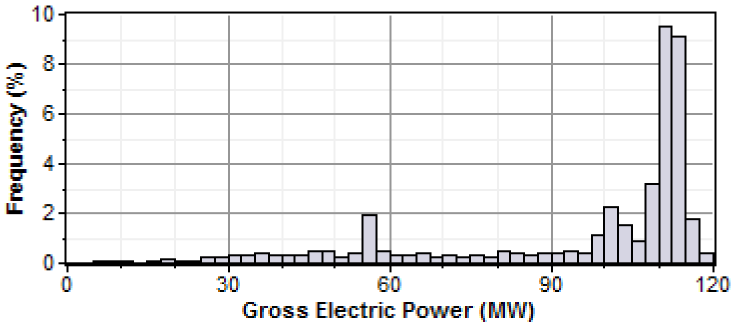
For example, consider a system with a power block design gross output rating of 111 MW and a solar multiple of one (SM=1) and no thermal storage. The following frequency distribution graph shows that the power block never generates electricity at its rated capacity, and generates less than 80% of its rated capacity for most of the time that it generates electricity:



For the same system with a solar multiple chosen to minimize LCOE (in this example SM=1.5), the power block generates electricity at or slightly above its rated capacity almost 15% of the time:



Adding thermal storage to the system changes the optimal solar multiple, and increases the amount of time that the power block operates at its rated capacity. In this example, the optimal storage capacity (full load hours of TES) is 3 hours with SM=1.75, and the power block operates at or over its rated capacity over 20% of the time:



Note. For clarity, the frequency distribution graphs above exclude nighttime hours when the gross power output is zero.

Reference Weather Conditions for Field Sizing

The design weather conditions values are reference values that represent the solar resource at a given location for solar field sizing purposes. The field sizing equations require three reference condition variables:

- Ambient temperature
- Direct normal irradiance (DNI)
- Wind velocity

The values are necessary to establish the relationship between the field aperture area and power block rated capacity for solar multiple (SM) calculations.

Note. The design values are different from the data in the weather file. SAM uses the design values to size the solar field before running simulations. During simulations, SAM uses data from the weather file you choose on the Location and Resource page.

The reference ambient temperature and reference wind velocity variables are used to calculate the design heat losses, and do not have a significant effect on the solar field sizing calculations. Reasonable values for those two variables are the average annual measured ambient temperature and wind velocity at the project location. For the physical trough model, the reference temperature and wind speed values are hard-coded and cannot be changed. The linear Fresnel and generic solar system models allow you to specify the reference ambient temperature value, but not the wind speed. The empirical trough model allows you to specify both the reference ambient temperature and wind speed values.

The reference direct normal irradiance (DNI) value, on the other hand, does have a significant impact on the solar field size calculations. For example, a system with reference conditions of 25°C, 950 W/m^2, and 5 m/s (ambient temperature, DNI, and wind speed, respectively), a solar multiple of 2, and a 100 MWe power block, requires a solar field area of 871,940 m^2. The same system with reference DNI of 800 W/m^2 requires a solar field area of 1,055,350 m^2.

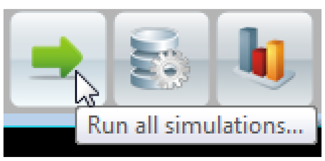
In general, the reference DNI value should be close to the maximum actual DNI on the field expected for the location. For systems with horizontal collectors and a field azimuth angle of zero in the Mohave Desert of the United States, we suggest a design irradiance value of 950 W/m2. For southern Spain, a value of 800 W/m2 is reasonable for similar systems. However, for best results, you should choose a value for your specific location using one of the methods described below.

Linear collectors (parabolic trough and linear Fresnel) typically track the sun by rotating on a single axis, which means that the direct solar radiation rarely (if ever) strikes the collector aperture at a normal angle. Consequently, the DNI incident on the solar field in any given hour will always be less than the DNI value in the resource data for that hour. The cosine-adjusted DNI value that SAM reports in simulation results is a measure of the incident DNI.

Using too low of a reference DNI value results in excessive "dumped" energy: Over the period of one year, the actual DNI from the weather data is frequently greater than the reference value. Therefore, the solar field sized for the low reference DNI value often produces more energy than required by the power block, and excess thermal energy is either dumped or put into storage. On the other hand, using too high of a reference DNI value results in an undersized solar field that produces sufficient thermal energy to drive the power block at its design point only during the few hours when the actual DNI is at or greater than the reference value.

To choose a reference DNI value:

1. Choose a weather file on the Location and Resource page.
2. Enter values for collector tilt and azimuth.
3. For systems with storage, specify the storage capacity and maximum storage charge rate defined on the Thermal Storage page.
4. Click run all simulations, or press Ctrl-G.



5. On the Results page, click Time Series.
6. On the Time Series tab, click Zoom to Fit (at the bottom of the input page).

Method 1: Maximum Cosine-adjusted DNI

7. Clear all of the check boxes and check DNI-cosine effect product (W/m2) variable.
8. Read the maximum annual value from the graph, and use this value for the reference DNI.

Method 2: Minimize "Dumped" Energy

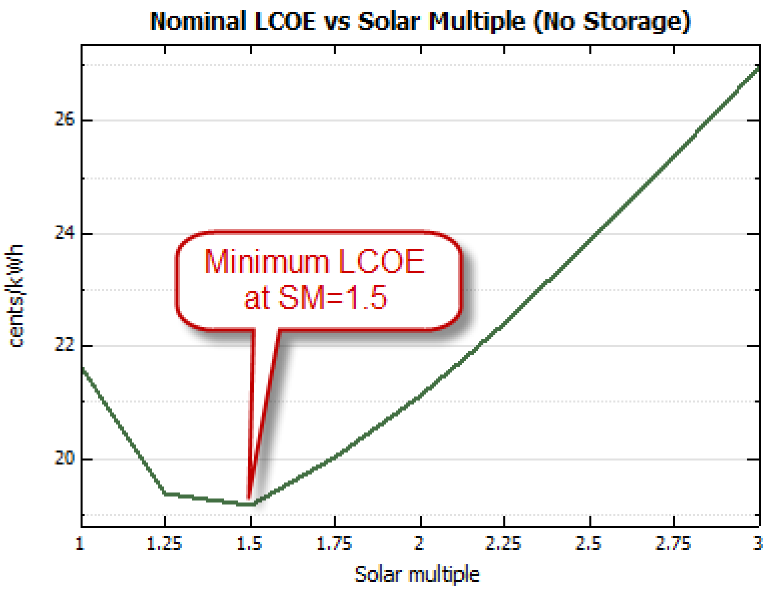
7. Clear all of the check boxes and check the dumped thermal energy variable(s).
8. If the amount of dumped thermal energy is excessive, try a lower value for the reference DNI value and run simulations again until the quantity of dumped energy is acceptable.

Optimizing the Solar Multiple

Representing the solar field aperture area as a solar multiple (Option 1) makes it possible to run parametric simulations in SAM and create graphs of LCOE versus solar multiple like the ones shown below. You can use this type of graph to find the optimal solar multiple.

For a parabolic trough system with no storage, the optimal solar multiple is typically between 1.4 and 1.5.

The graph shown below is for a system with no storage in Blythe, California, the optimal solar multiple is 2, meaning that the solar field aperture area should be chosen to be twice the area required to drive the power cycle at its rated capacity:



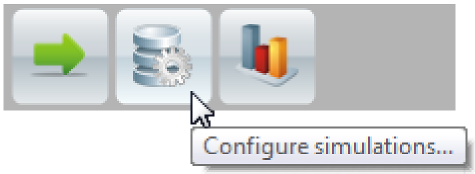
Because the optimal solar multiple depends on the LCOE, for accurate results, you should specify all of the project costs, financing, and incentive inputs in addition to the inputs specifying the physical characteristics of the solar field, power cycle and storage system before the optimization. However, for preliminary results, you can use default values for any variables for which you do not have values.

The following instructions describe the steps for optimizing the solar multiple for a preliminary system design that mostly uses default values except for a few key variables. This example is for a 50 MW system, but you can use the same procedure for a system of any size.

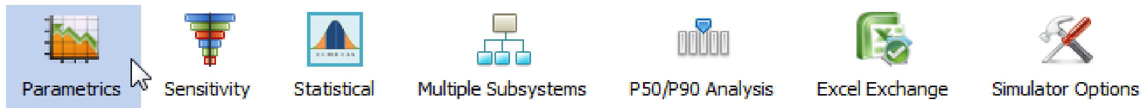
To optimize the solar field with no storage:

1. Create a new physical trough project with Utility IPP financing.
2. On the Location and Resource page, choose a location.
3. Follow the instructions above to find an appropriate irradiation at design value for your weather data. Use zero for both the collector tilt and azimuth variables.
4. On the Power Cycle page, for Design gross output, type 55 to specify a power block with a rated net electric output capacity of 50 MW (based on the default net conversion factor of 0.9).
5. On the Thermal Storage page, for **Full load hours of TES**, type 0 to specify a system with no storage.
6. On the Solar Field page, under **Solar Field Parameters**, choose **Option 1** (solar multiple) if it is not already active.

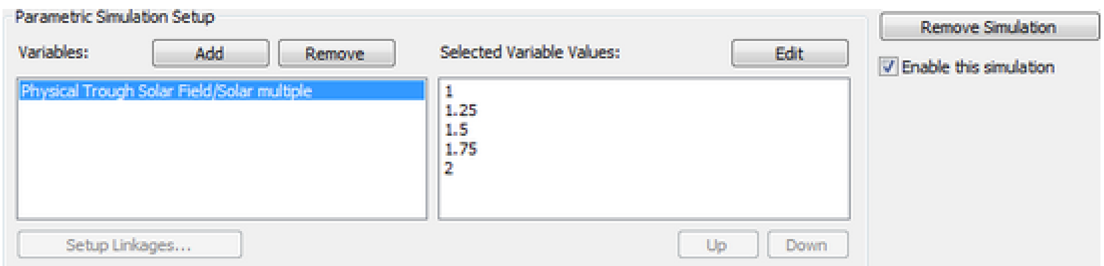
7. Click Configure simulations.



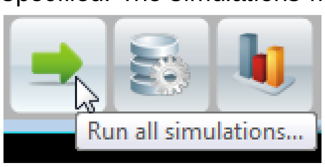
8. Click **Parametrics**.



9. Click **Add Parametric Simulation**.
10. Click **Add** to open the Choose Parametrics window.
11. In the Search box, type "solar multiple."
12. Check **Solar Multiple**.
13. Click **Edit** to open the Edit Parametric Values window.
14. Type the following values: Start Value = 1, End Value = 2, Increment = 0.25.
15. Click **Update**. The parametric simulation setup options should look like this:
16. Click **OK**.



17. Click Run all simulations. SAM will run a simulation for each of the 5 solar multiple values you specified. The simulations may take a few minutes to run.



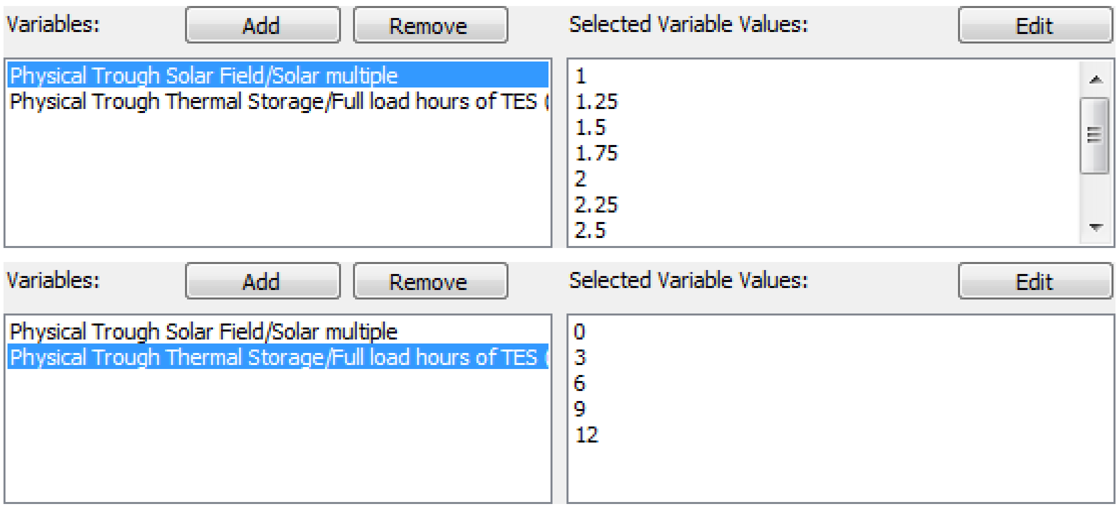
18. On the Results page, click **Add a new graph**.
19. Choose the following options: **Choose Simulation** = Parametric Set 1, **X Value** = {Solar Multiple}, **Y1 Values** = LCOE Nominal, **Graph Type** = Line Plot
20. Click **Accept**. SAM should display a graph that looks similar to the "Nominal LCOE vs Solar Multiple (No Storage)" graph above.
21. On the graph, find the solar multiple value that results in the lowest LCOE. If the minimum LCOE occurs at either end of the graph, you may need to add more values to the solar multiple parametric variable to find the optimal value.

Optimal Solar Multiple for a System with Storage

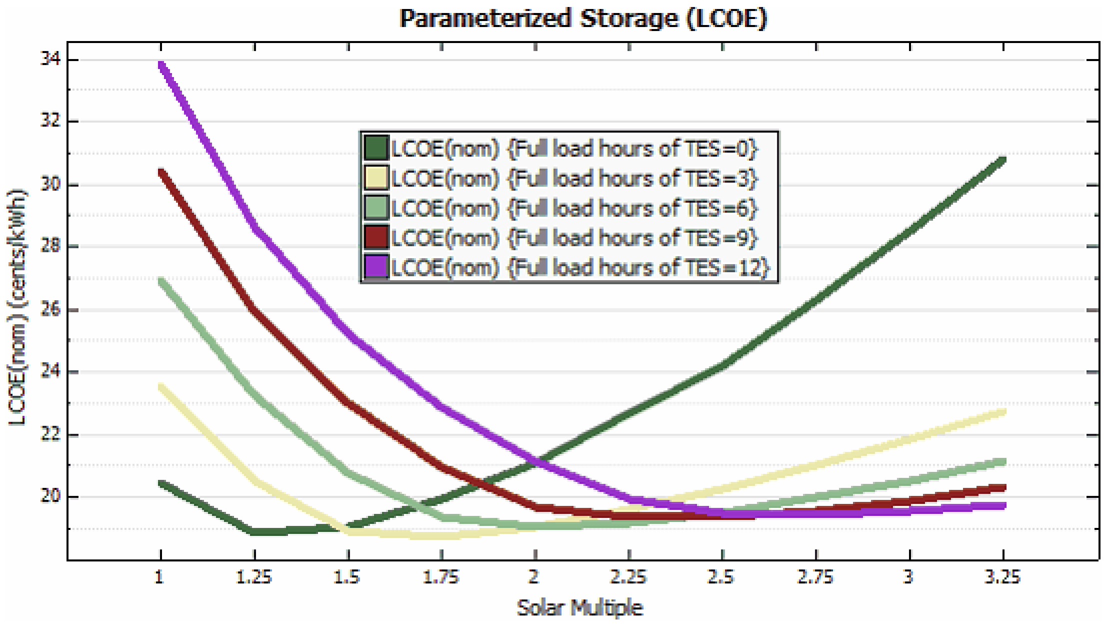
Note. The linear Fresnel model in the current version of SAM does not include a storage option.

Adding storage to the system introduces another level of complexity: Systems with storage can increase system output (and decrease the LCOE) by storing energy from an larger solar field for use during times when the solar field output is below the design point. However, the thermal energy storage system's cost and thermal losses also increase the LCOE.

To find the optimal combination of solar multiple and storage capacity for systems with thermal storage, run a parametric analysis as described above, but with two parametric variables instead of one: Solar multiple and Full load hours of TES (storage capacity). The parametric setup options should look similar to this:



After running simulations, you will be able to create a graph like the one below that allows you to choose the combination of solar multiple and storage capacity that minimizes the LCOE. For example, the following graph shows that for a system in Blythe, California, the optimal combination of solar multiple and thermal storage capacity is SM = 1.75 and Hours of TES = 3.



Each line in the graph represents a number of hours of thermal energy storage from the list we saw in the list of parametric values for the Equivalent Full Load Hours of TES variable: 0, 3, 6, 9, and 12 hours of storage.

For the no storage case (the dark green line, zero hours of storage), the lowest levelized cost of energy occurs at a solar multiple of 1.25. For a given storage capacity, as the solar multiple increases, both the area-dependent installation costs electricity output increase. The interaction of these factors causes the levelized cost of energy to decrease as the solar multiple increases from 1, but at some point the cost increase overwhelms the benefit of the increased electric energy output, and the levelized cost of energy begins to increase with the solar multiple.

Simplified Steps for Optimizing the Solar Field

If you are performing a preliminary analysis or learning to use SAM, you can use the following simplified steps, using default values for most of the inputs:

1. Choose a location on the Location and Resource page.
2. Specify the power cycle capacity on the Power Cycle page.
3. Choose an irradiation at design value on the Solar Field page.
4. Optimize the solar field aperture area using Option 1.

Overall Steps for Optimizing the Solar Field

1. Choose a location on the Location and Resource page.
2. Specify the power cycle capacity and other characteristics on the Power Cycle page.
3. Specify characteristics of the solar field components on the Receivers (HCEs) and Collectors (SCAs) pages.
4. If the system includes thermal energy storage, specify its characteristics on the Thermal Storage page. (Note. For systems with storage, use the optimization process in Step 8 below to find the optimal storage capacity.)

5. Define the project costs on the Trough System Costs page.
6. Configure a single loop and specify solar field heat transfer fluid (HTF) properties on the Solar Field page.
7. Specify the collector orientation on the Solar Field page.
8. Choose an irradiation at design value on the Solar Field page.
9. Either optimize the solar field aperture area using Option 1, or specify the solar field area explicitly using Option 2 on the Solar Field page.
10. Refine your analysis by adjusting other model parameters.

7.5.3 Collector and Receiver

Linear Fresnel Boiler Geometry / Superheater Geometry

This dropdown specifies whether the collector and receiver geometry displayed on the Collector and Receiver page corresponds to the boiler or superheater section. If the Superheater has unique geometry checkbox on the Solar Field page is not selected, the boiler geometry will apply to all modules in the collector loop. If the checkbox is selected, the boiler geometry applies only to the first Number of modules in boiler section modules, and the remaining superheater modules inherit geometry from the inputs that appear when the Linear Fresnel Superheater Geometry option is selected from the dropdown menu.

Collector Geometry and Optical Performance

Reflective aperture area, m²

The total reflective aperture area for the module. This value is multiplied by the collector optical efficiency and the solar irradiance value to determine the total thermal energy incident on the module's receiver.

Length of collector module, m

The length of a collector module along the receiver axis. This value is used to calculate thermal losses that are expressed in units of W/m.

Tracking error

A fixed optical loss representing collector tracking error. This value multiplies the other fixed optical losses and the time-varying collector optical efficiency to determine the total optical efficiency.

Geometry effects

A fixed optical loss representing collector geometry effects. This value multiplies the other fixed optical losses and the time-varying collector optical efficiency to determine the total optical efficiency.

Mirror reflectivity

The optical loss fraction associated with mirror reflectivity, excluding soiling. This value multiplies the other fixed optical losses and the time-varying collector optical efficiency to determine the total optical efficiency.

Mirror soiling

The optical loss fraction associated with soiling on the mirrors. This value multiplies the other fixed optical losses and the time-varying collector optical efficiency to determine the total optical efficiency.

General optical error

Other optical loss not captured in the time-varying collector optical efficiency table/polynomials and fixed derates. This value multiplies the other fixed optical losses and the time-varying collector optical efficiency to determine the total optical efficiency.

Optical characterization method

You can select one of three options for characterizing the optical performance of the solar field in addition to the fixed optical losses specified in the Collector Geometry and Optical Performance section. The three methods determine how the optical efficiency varies with sun position.

The optical efficiency is defined as follows:

Optical Efficiency = Total Thermal Energy Absorbed by Receiver ÷ (Direct Normal Irradiance × Actual Aperture Area)

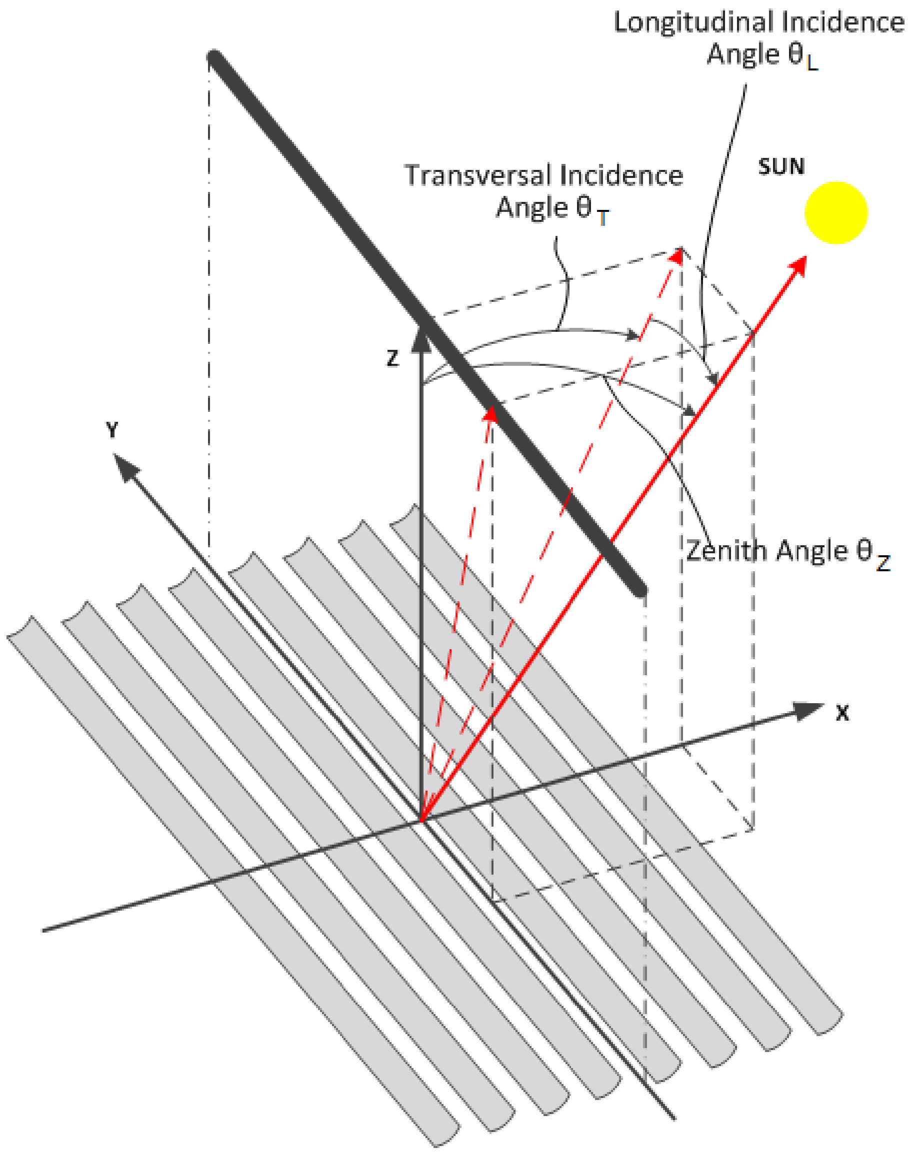
Solar position table

The solar position table option allows you to specify optical efficiency of the solar field as a function of solar azimuth and zenith angles. SAM uses a solar azimuth angle convention where true North is equal to -180/+180° and South equals 0°. The solar zenith angle is zero when the sun is directly overhead and 90° when the sun is at the horizon.

The solar position may contain any number of rows and columns, but should contain enough information to fully define the performance of the solar field at all sun positions for which the field will operate. The table must contain more than one row and column.

Collector incidence angle table

The collector incidence angle table option allows you to specify solar field optical efficiency as a function of the longitudinal and transversal solar incidence angles. The collector incidence angles are defined as shown in the following figure, where the transversal incidence angle is given as ϕ_T and the longitudinal incidence angle is ϕ_L. The solar zenith angle is θ_z.



Incidence angle modifiers

The incidence angle modifier option allows you to specify optical performance of the solar field collectors using polynomial equations (up to fourth order) in both the transversal and longitudinal incidence angle directions. Refer to the Collector incidence angle table input documentation (above) for descriptions of the transversal (ϕ_T) and longitudinal (ϕ_L) collector angles.

Solar Position/Collector Incidence Angle Table

Import

Import a table from a text or data file. The file can contain values separated by comma, space, or tab characters, but must be formatted according to the following rules:

- The first row in the file specifies the angles for the solar azimuth (for the Solar position table) or collector transversal incidence (for the Collector incidence angle table). The first entry of this row should be blank.

- Each additional row specifies optical efficiency for a specific zenith angle (for the Solar position table) or longitudinal incidence angle (for the Collector incidence angle table). The first entry of the row must be the zenith or longitudinal incidence angle corresponding to the optical efficiency entries in that row.
- The rows of the table should be sorted according to zenith/longitudinal incidence angle from lowest to highest.

An example tab-delimited table is as follows, where numbers in bold correspond to the solar zenith (row headers) and azimuth (column headers) angles:

	-180	**90**	**0**	**90**	**180**
0	1.0	1.0	1.0	1.0	1.0
30	0.95	0.98	0.99	0.98	0.95
60	0.60	0.70	0.75	0.70	0.60
90	0.0	0.0	0.0	0.0	0.0

Note that SAM automatically sizes the table on the Collector and Receiver page to match the size of the array that is being imported.

Export

Export the optical efficiency table on the Collector and Receiver page to a text file.

Copy

Copy the optical efficiency table on the Collector and Receiver page to the clipboard for transfer to an optical efficiency table in another case or to other text applications.

Paste

Paste an optical efficiency table from another SAM case or from a text file into the active case.

Rows

Specify the number of desired rows in the table.

Cols

Specify the number of desired columns in the table.

Incidence Angle Modifier Coefficients

This option allows you to specify the optical performance of the collector field as functions of the transversal and longitudinal incidence angles where the performance is expressed in polynomial form.

Transverse incidence angle modifier

The incidence angle modifier polynomial for the transversal incidence angle, as defined in the documentation for the collector incidence angle table (above). The polynomial to calculate the optical efficiency reduction associated with deviation of the irradiation incidence angle in the transversal plane is as follows:

$$IAM_T = C_0 + C_1 \cdot \phi_T + C_2 \cdot \phi_T^2 + C_3 \cdot \phi_T^3 + C_4 \cdot \phi_T^2$$

where ϕ_T is the transversal incidence angle.

Longitudinal incidence angle modifier

The incidence angle modifier polynomial for the longitudinal incidence angle, as defined in the documentation for the collector incidence angle table (above). The polynomial to calculate the optical efficiency reduction associated with deviation of the irradiation incidence angle in the longitudinal plane is as follows:

$$IAM_L = C_0 + C_1 \cdot \phi_L + C_2 \cdot \phi_L^2 + C_3 \cdot \phi_L^3 + C_4 \cdot \phi_L^4$$

where ϕ_L is the longitudinal incidence angle.

Receiver Geometry and Heat Loss

Polynomial heat loss model/Evacuated tube model

You can specify the thermal losses from the solar field receiver components using one of two approaches: the first approach allows general specification of thermal losses using polynomial equations. The polynomials provide heat loss as a function of steam temperature with a correction based on wind velocity, and heat loss is evaluated at each collector module in the loop. The second option allows the use of a detailed evacuated tube receiver model. Select the model using the dropdown menu in this section.

Polynomial fit heat loss model

Steam temperature adjustment

This polynomial gives thermal losses in the solar field receiver component as a function of the difference between steam temperature and ambient dry-bulb temperature in degrees Celsius. Thermal losses are evaluated at each collector module in the loop using the following expression for the coefficient of heat loss [W/m]:

$$F_{hl}(T) = C_0 + C_1 \cdot \Delta T_{local} + C_2 \cdot \Delta T_{local}^2 + C_3 \cdot \Delta T_{local}^3 + C_4 \cdot \Delta T_{local}^4$$

where ΔT_{local} is the local (to the module) difference between the steam temperature and ambient dry bulb temperature.

Wind velocity adjustment

SAM allows you to adjust the thermal loss coefficient calculated from the Steam temperature adjustment polynomial ($F_{hl}(T)$). The resulting value from the wind velocity polynomial multiplies the steam temperature heat loss polynomial, as follows:

$$F_{hl}(V_{wind}) = C_0 + C_1 \cdot V_{wind} + C_2 \cdot V_{wind}^2 + C_3 \cdot V_{wind}^3 + C_4 \cdot V_{wind}^4$$

$$F_{hl,total} = F_{hl}(T) \cdot F_{hl}(V_{wind})$$

Evacuated tube heat loss model

Absorber tube inner diameter (m)

Inner diameter of the receiver absorber tube, this surface in direct contact with the heat transfer fluid.

Absorber tube outer diameter (m)

Outer diameter of the receiver absorber tube, the surface exposed to the annular vacuum.

Glass envelope inner diameter (m)

Inner diameter of the receiver glass envelope tube, the surface exposed to the annular vacuum.

Glass envelope outer diameter (m)

Outer diameter of the receiver glass envelope tube, the surface exposed to ambient air.

Absorber flow plug diameter (m)

A non-zero value represents the diameter of an optional plug running axially and concentrically within the receiver absorber tube. A zero value represents a receiver with no plug. The plug allows for an increase in the receiver absorber diameter while maintaining the optimal heat transfer within the tube heat transfer fluid. For a non-zero value, be sure to use annular flow for the absorber flow pattern option.

Internal surface roughness

The surface roughness of the inner receiver pipe surface exposed to the heat transfer fluid, used to determine flow shear force and the corresponding pressure drop across the receiver.

Surface roughness is important in determining the scale of the pressure drop throughout the system. As a general rule, the rougher the surface, the higher the pressure drop (and parasitic pumping power load). The surface roughness is a function of the material and manufacturing method used for the piping. A conservative roughness value for extruded steel pipe (the type often used for the absorber pipe) is about 3e-6 meters. The default value of 4.5e-5 m is based on this value and the absorber tube inner diameter value of 0.066 m: 3e-6 m / 6.6e-2 m = 4.5e-5.

Absorber flow pattern (m)

Use standard tube flow when the absorber flow plug diameter is zero. Use annual flow with a non-zero absorber flow plug diameter.

Absorber material type

The material used for the absorber tube. Choose from stainless steel or copper.

Variant weighting fraction

The fraction of the solar field that consists of the active receiver variation. For each receiver type, the sum of the four variations should equal one. You can use the receiver variations to model a solar field with receivers in different conditions. If you want all of the receivers in the field to be identical, then you can use a single variation and assign it a variant weighting fraction of 1.

When you use more than one receiver variation, be sure that the sum of the four variant weighting fractions is 1.

Here's an example of an application of the receiver variations for a field that consists of a two receiver types. The first type, Type 1, represents receivers originally installed in the field. Type 2 represents replacement receivers installed as a fraction of the original receivers are damaged over time.

Over the life of the project, on average, 5 percent of the Type 1 receivers have broken glass envelopes, and another 5 percent have lost vacuum in the annulus. We'll also assume that degraded receivers are randomly distributed throughout the field -- SAM does not have a mechanism for specifying specific locations of different variations of a given receiver type. To specify this situation, we would start with Type 1, and use Variation 1 to represent the 90 percent of intact receivers, assigning it a variant weighting fraction of 0.90. We'll use Variation 2 for the 5 percent of receivers with broken glass envelopes, giving it a weighting fraction of 0.05, and Variation 3 for the other 5 percent of lost-vacuum receivers with a weighting fraction of 0.05. We'll assign appropriate values to the parameters for each of the two damaged receiver variations.

Next, we'll specify Type 2 to represent intact replacement receivers. We will us a single variation for the intact Type 2 receivers.

On the Solar Field page, we'll specify the single loop configuration (assuming a loop with eight assemblies), using Type 2 for the first and second assembly in the loop, and Type 1 receivers (with the variant weighting we assigned on the Receivers page) for the remaining six assemblies in the loop

Absorber absorptance

The ratio of radiation absorbed by the absorber to the radiation incident on the absorber.

Absorber emittance

The energy radiated by the absorber surface as a function of the absorber's temperature. You can either specify a table of emittance and temperature values, or specify a single value that applies at all temperatures.

Envelope absorptance

The ratio of radiation absorbed by the envelope to the radiation incident on the envelope, or radiation that is neither transmitted through nor reflected from the envelope. Used to calculate the glass temperature. (Does not affect the amount of radiation that reaches the absorber tube.)

Envelope emittance

The energy radiated by the envelope surface.

Envelope transmittance

The ratio of the radiation transmitted through the glass envelope to the radiation incident on the envelope, or radiation that is neither reflected nor refracted away from the absorber tube.

Broken glass

Option to specify that the envelope glass has been broken or removed, indicating that the absorber tube is directly exposed to the ambient air.

Annulus gas type

Gas type present in the annulus vacuum. Choose from Hydrogen, air, or Argon.

Annulus pressure (torr)

Absolute pressure of the gas in the annulus vacuum, in torr, where 1 torr = 133.32 Pa

Estimated avg. heat loss (W/m)

An estimated value representing the total heat loss from the receiver under design conditions. SAM uses the value to calculate the total loop conversion efficiency and required solar field aperture area for the design point values on the Solar Field page. It does not use the value in simulation calculations.

Bellows shadowing

An optical derate factor accounting for the fraction of radiation lost after striking the mechanical bellows at the ends of the receiver tubes.

Dirt on receiver

An optical derate factor accounting for the fraction of radiation lost due to dirt and soiling on the receiver.

Aggregate Weighted Losses

Average field temp difference at design

The effective temperature for thermal loss estimates, equal to the average solar field temperature. This temperature is used to evaluate thermal losses from the solar field receivers (polynomial heat loss model only) and from piping as specified on the Parasitics page. This value is calculated as the average of the Field inlet temperature and Field outlet temperature on the Solar Field page.

Heat loss at design

Calculated estimate of thermal losses at the Average field temp difference at design. In the case of the polynomial heat loss model, the estimate is calculated based on the difference between the average temperature and the design-point ambient temperature from the Solar Field page. In the case of the evacuated tube receiver model, the estimate is based on the user-specified Estimated avg. heat loss values on the Collector and Receiver page.

Receiver thermal derate

Calculated value indicating the estimated thermal efficiency of the solar field receivers. This value is calculated based on the Heat loss at design calculated value, and is used only to size the solar field aperture area. Note that this value is not used in annual hourly performance calculations.

Receiver optical derate

The reduction in optical efficiency associated with envelope transmittance and receiver soiling. This derate is calculated as a weighted sum for the four receiver variants and only applies to the evacuated receiver model option.

Collector optical loss at normal incidence

The optical efficiency from the optical table or incident angle modifier polynomials at normal solar incidence.

7.5.4 Power Cycle

The power cycle converts thermal energy to electric energy. The power cycle is assumed to consist of a superheated two-stage turbine with multiple extractions for feedwater heating and a reheat extraction between the high and low pressure turbine stages. You specify the design-point efficiency of this cycle on the Power Cycle page, and SAM models the part-load behavior with normalized performance curves as a function of steam inlet temperature, mass flow rate, and ambient temperature. The ambient temperature correction uses the wet-bulb temperature for wet-cooled systems and hybrid systems and the dry-bulb temperature for dry cooled and hybrid cooled systems.

Page numbers relevant to this section from the Wagner (2011) and Kistler B (1986) references are:

- Wagner 55-63
- Kistler 224

The power cycle page displays variables that specify the design operating conditions for the steam Rankine cycle used to convert thermal energy to electricity.

Plant Design

Design Turbine Gross Output (MWe)

The power cycle's design output, not accounting for parasitic losses.

Estimated Gross to Net Conversion Factor

An estimate of the ratio of the electric energy delivered to the grid to the power cycle's gross output. SAM uses the factor to calculate the power cycle's nameplate capacity for capacity-related calculations, including the estimated total cost per net capacity value on the System Costs page, and the capacity factor reported in the results.

Net Nameplate Capacity (MWe)

The power cycle's nameplate capacity, calculated as the product of the design gross output and estimated gross to net conversion factor.

Net Nameplate Capacity (MWe) = Design Gross Output (MWe) × Estimated Gross to Net Conversion Factor

Rated Cycle Efficiency

The thermal to electric conversion efficiency of the power cycle under design conditions.

Design Thermal Input Power (MWt)

The turbine's design thermal input. It is the thermal energy required at the power block inlet for it to operate at its design point, as defined by the value of the nameplate electric capacity and an estimate of the parasitic losses: Design thermal power = nameplate electric capacity + total parasitic loss estimate. (See the Parasitics page for a description of the total parasitic loss estimate.)

High Pressure turbine inlet pressure (bar)

The inlet pressure of the high pressure turbine at design. This is one of the values necessary to define the cycle at design. Current steam properties are limited to 190 bar, so this pressure should be set lower than 190 bar so that the property calculations do not fail at higher pressures calculated upstream of the turbine. The simulation may stop or produce warnings if the property routing encounters pressures greater than 190 bar.

High Pressure Turbine Outlet Pressure (bar)

The outlet pressure of the high pressure turbine at design. This is another value necessary to define the cycle at design.

Design Reheat Mass Flow Rate Fraction

The fraction of steam mass flow rate that exits the high pressure turbine and enters the reheater. The remaining flow is transferred to the feedwater heaters for use in preheating.

Fossil Backup Boiler LHV Efficiency

The backup boiler's lower heating value efficiency, used to calculate the quantity of gas required by the boiler.

Steam cycle blowdown fraction

The fraction of the steam mass flow rate in the power cycle that is extracted and replaced by fresh water. This fraction is multiplied by the steam mass flow rate in the power cycle for each hour of plant operation to determine the total required quantity of power cycle makeup water. The blowdown fraction accounts for water use related directly to replacement of the steam working fluid. The default value of 0.013 for the wet-cooled case represents makeup due to blowdown quench and steam cycle makeup during operation and startup. A value of 0.016 is appropriate for dry-cooled systems to account for additional wet-surface air cooling for critical Rankine cycle components.

Plant Cooling Mode

Condenser type

Choose either an air-cooled condenser (dry cooling), evaporative cooling (wet cooling), or hybrid cooling system.

In hybrid cooling a wet-cooling system and dry-cooling share the heat rejection load. Although there are many possible theoretical configurations of hybrid cooling systems, SAM only allows a parallel cooling option.

Ambient temp at design (ºC)

The ambient temperature at which the power cycle operates at its design-point-rated cycle conversion efficiency. For the air-cooled condenser option, use a dry bulb ambient temperature value. For the evaporative condenser, use the wet bulb temperature.

Reference Condenser Water dT (ºC)

For the evaporative type only. The temperature rise of the cooling water across the condenser under design conditions, used to calculate the cooling water mass flow rate at design, and the steam condensing temperature.

Approach temperature (ºC)

For the evaporative type only. The temperature difference between the circulating water at the condenser inlet and the wet bulb ambient temperature, used with the ref. condenser water dT value to determine the condenser saturation temperature and thus the turbine back pressure.

ITD at design point (ºC)

For the air-cooled type only. Initial temperature difference (ITD), difference between the temperature of steam at the turbine outlet (condenser inlet) and the ambient dry-bulb temperature.

Note. When you adjust the ITD, you are telling the model the conditions under which the system will achieve the thermal efficiency that you've specified. If you increase the ITD, you should also modify the thermal efficiency (and/or the design ambient temperature) to accurately describe the design-point behavior of the system. The off-design penalty in the modified system will follow once the parameters are corrected.

Condenser pressure ratio

For the air-cooled type only. The pressure-drop ratio across the air-cooled condenser heat exchanger, used to calculate the pressure drop across the condenser and the corresponding parasitic power required to maintain the air flow rate.

Minimum condenser pressure

The minimum condenser pressure in inches if mercury prevents the condenser pressure from dropping below the level you specify. In a physical system, allowing the pressure to drop below a certain point can result in physical damage to the system. For evaporative (wet cooling), the default value is 1.25 inches of mercury. For air-cooled (dry cooling), the default is 2 inches of mercury. For hybrid systems, you can use the dry-cooling value of 2 inches of mercury.

Cooling system part load levels

The cooling system part load levels tells the heat rejection system model how many discrete operating points there are. A value of 2 means that the system can run at either 100% or 50% rejection. A value of three means rejection operating points of 100% 66% 33%. The part load levels determine how the heat rejection operates under part load conditions when the heat load is less than full load. The default value is 2, and recommended range is between 2 and 10. The value must be an integer.

Operation

Low-Resource Standby Period (hours)

During periods of insufficient flow from the heat source due to low thermal resource, the power block may enter standby mode. In standby mode, the cycle can restart quickly without the startup period required by a cold start. The standby period is the maximum number of hours allowed for standby mode. This option is only available for systems with thermal storage. Default is 2 hours.

Fraction of Thermal Power Needed for Standby

The fraction of the turbine's design thermal input required from storage to keep the power cycle in standby mode. This thermal energy is not converted into electric power. Default is 0.2.

Startup Time (hours)

The time in hours that the system consumes energy at the startup fraction before it begins producing electricity. If the startup fraction is zero, the system will operate at the design capacity over the startup time. Default is 0.5 hours.

Fraction of Thermal Power Needed for Startup

The fraction of the turbine's design thermal input required by the system during startup. This thermal energy is not converted to electric power. Default is 0.75.

Minimum Operation Fraction

The fraction of the nameplate electric capacity below which the power block does not generate electricity. Whenever the power block output is below the minimum load and thermal energy is available from the solar field, the field is defocused. For systems with storage, solar field energy is delivered to storage until storage is full. Default is 0.25.

Max Turbine Over Design Operation Fraction

The maximum allowable power block output as a fraction of the electric nameplate capacity. Whenever storage is not available and the solar resource exceeds the design value of 950 W/m2, some heliostats in the solar field are defocused to limit the power block output to the maximum load. Default is 1.05.

Fossil Dispatch Mode

SAM operates the fossil backup system based on the option you choose for Fossil dispatch mode.

Minimum Backup Level

In the Minimum Backup Level mode, whenever the fossil fill fraction is greater than zero for any dispatch period, the system is considered to include a fossil burner that heats the HTF before it is delivered to the power cycle.

In this mode, the fossil fill fraction defines the fossil backup as a function of the thermal energy from the solar field in a given hour and the design turbine gross output.

For example, for an hour with a fossil fill fraction of 1.0 when solar energy delivered to the power cycle is less than that needed to run at the power cycle design gross output, the backup heater would supply enough energy to "fill" the missing heat, and the power cycle would operate at the design gross output. If, in that scenario, solar energy (from either the field or storage system) is driving the power cycle at full load, the fossil backup would not operate. For a fossil fill fraction of 0.75, the heater would only be fired when solar output drops below 75% of the power cycle's design gross output.

Supplemental Operation

In the Supplemental Operation mode, SAM assumes a fossil backup system of a fixed maximum capacity, for example, capable of supplying 10 MW of thermal energy to the HTF.

The fossil fill fraction defines the size of the fossil backup as a fraction of the power cycle design gross output and this energy is added to the input from the solar field and storage system.

Operation of the power cycle in a given hour is constrained by the **Max turbine over design operation fraction** and **Minimum operation fraction**. For hours that the added fossil energy is insufficient to meet the minimum requirement, fossil backup is not dispatched.

SAM includes the cost of fuel for the backup system in the levelized cost of energy and other metrics reported in the results, and reports the energy equivalent of the hourly fuel consumption in the time series simulation results. The cost of fuel for the backup system is defined on the Tower System Costs page.

Dispatch Control

The dispatch control variables each have six values, one for each of six possible dispatch periods.

Hybrid Cooling Dispatch

When you choose Hybrid as the condenser type, the hybrid dispatch table specifies how much of the cooling load should be handled by the wet-cooling system for each of 6 periods in the year. The periods are specified in the matrices at the bottom of the Power Cycle page. Each value in the table is a fraction of the design cooling load. For example, if you want 60% of heat rejection load to go to wet cooling in Period 1, type 0.6 for Period 1. Directing part of the heat rejection load to the wet cooling system reduces the total condenser temperature and improves performance, but increases the water requirement. SAM sizes the wet-cooling system to match the maximum fraction that you specify in the hybrid dispatch table, and sizes the air-cooling system to meet the full cooling load.

Fossil Fill Fraction

Determines how much energy the backup boiler delivers during hours when there is insufficient energy from the solar field to drive the power cycle at its design output capacity. A value of one for a given dispatch period ensures that the power cycle operates at its design output for all hours in the period: The boiler "fills in" the energy not delivered by the solar field or storage system. For a fossil fill fraction less than one, the boiler supplies enough energy to drive the power cycle at a fraction of its design point. To define a system with no fossil backup, use a value of zero for all six dispatch periods. See Storage and Fossil Backup Dispatch Controls for details.

TOD Factor

The time-of-delivery (TOD) factors allow you to specify a set of TOD power price factors to model time-dependent pricing for projects with one of the Utility Financing options.

The TOD factors are a set of multipliers that SAM uses to adjust the PPA price based on time of day and month of year for utility projects. The TOD factors work in conjunction with the assumptions on the Financing page.

> **Note.** For utility projects with no TOD factors, set the value for all periods to one.

For the CSP models, although the TOD power price factors are financial model inputs, they are on the Storage page because it includes other time-dependent variables, and there may be a relationship between the dispatch factors and the TOD power price factors. For PV and other technology models, the TOD power price factors are on a separate Time of Delivery Factors input page. For a description of how to specify the TOD power price factors for all technology models, see Time of Delivery Factors.

For a description of TOD-related simulation results, see PPA Revenue with TOD Factors.

Dispatch Schedules

The dispatch schedules determine when each of the six periods apply during weekdays and weekends throughout the year.

To specify a weekday or weekend schedule:

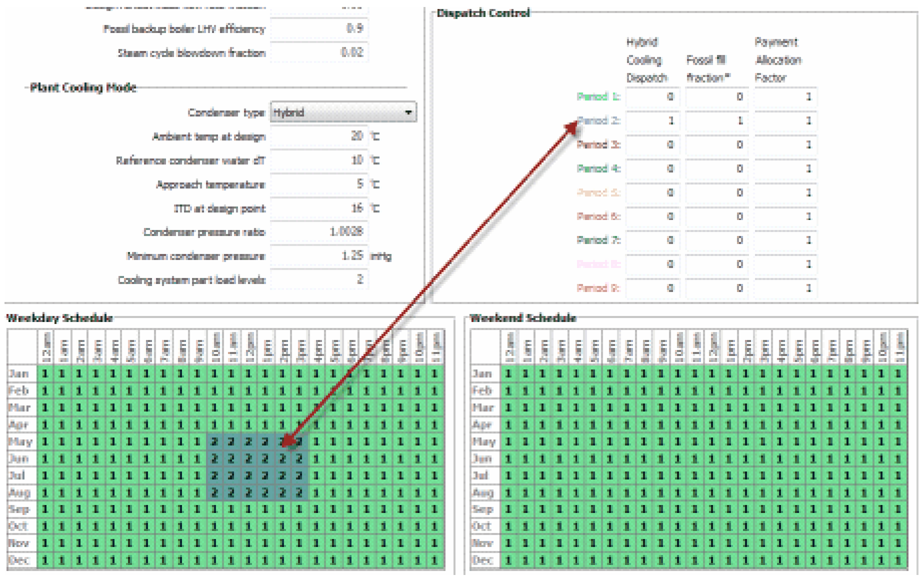
1. Assign values as appropriate to the Storage Dispatch, Turbine Output Fraction, Fossil Fill Fraction, and TOD Factor for each of the up to nine periods.
2. Use your mouse to draw a rectangle in the matrix for the first block of time that applies to period 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

3. Type the number 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	[illegible]	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

4. SAM displays the period number in the squares that make up the rectangle, and shades the rectangle to match the color of the period.



5. Repeat Steps 2-4 for each of the remaining periods that apply to the schedule for both weekdays and weekends.

Note. SAM assumes that the first simulation time step is on a Monday (in the hour ending at 1 a.m.), and that weekends are Saturday and Sunday.

7.5.5 Parasitics

The parameters on the Parasitics page describe parasitic electrical loads and other losses in the linear fresnel system.

Page numbers relevant to this section from the Kistler B (1986) reference is:

- Kistler 224

The parasitic loss variables are factors that SAM uses to calculate the estimated total parasitic loss and hourly parasitic losses, which are described in more detail below.

SAM calculates two types parasitic loss values. The first is an estimate of the total parasitic losses used to calculate the power cycle design thermal input, and the second are the hourly values calculated during simulation of the system's performance.

Note. Parasitic losses from components that do not exist in the system should be set to zero.

Parasitic Energy Consumption

Piping thermal loss coefficient (W/K-m2-aper)

Thermal loss per area of collector aperture as calculated on the Solar Field page.

Tracking Power (W/m2)

The electric power in Watts per area of collector aperture required by the tracking mechanism of each collector in the field during hours of operation.

Tracking Power Loss (W)

SAM calculates the power loss in Watts based on the W/m2 value you specify above.

Fraction of rated gross power consumed at all times

The fraction of design-point gross power output from the power cycle that is used for parasitics associated with facility operation, HVAC, control, lighting, etc.

Fixed parasitic loss (MWe)

SAM calculates the fixed loss based on the fraction you specify above.

Balance of Plant Parasitic (MWe/MWcap)

Losses as a fraction of the power cycle electrical power output that apply in hours when the power block operates.

Aux heater, boiler parasitic (MWe/MWcap)

Parasitic power consumption incurred during operation of the backup fossil boiler, as a function of thermal power production of the fossil system. This parasitic is only applicable for systems with active fossil backup, and applies during hours in which the fossil system produces thermal power.

7.6 Dish Stirling

A dish-Stirling system consists of a parabolic dish-shaped collector, receiver and Stirling engine. The collector focuses direct normal solar radiation on the receiver, which transfers heat to the engine's working fluid. The engine in turn drives an electric generator. A dish-Stirling power plant can consist of a single dish or a field of dishes.

For a general description of the model, see Overview.

The dish-Stirling input pages are:

- Dish System Costs
- System Library
- Solar Field
- Collector
- Receiver
- Stirling Engine
- Parasitics
- Reference Inputs

7.6.1 Dish Stirling Overview

A dish-Stirling system is a type of concentrating solar power (CSP) system that consists of a parabolic dish-shaped collector, receiver and Stirling engine. The collector focuses direct normal solar radiation on the receiver, which transfers heat to the engine's working fluid. The engine in turn drives an electric generator. A dish-Stirling power plant can consist of a single dish or a field of dishes.

SAM's dish-Stirling performance model uses the TRNSYS implementation of the energy prediction model described in the thesis *Stirling Dish System Performance Prediction Model (*Fraser 2008) http://sel.me.wisc.edu/publications/theses/fraser08.zip (4.1 MB).

To learn more about the model's implementation, you can explore the source code written in FORTRAN for the dish Stirling model in the following folder of your SAM installation folder (c:\SAM\SAM 2014.1.14 by default): C:\exelib\trnsys\source. The dish Stirling model files are:

- sam_pf_dish_receiver_type296.for
- sam_pf_dish_parasitic_type298.for
- sam_pf_dish_engine_type297.for
- sam_pf_dish_collector_type295.for

The dish-Stirling input pages are:

- Dish System Costs
- System Library
- Solar Field
- Collector
- Receiver
- Stirling Engine
- Parasitics
- Reference Inputs
- Exchange Variables

7.6.2 System Library

To view the System Library page, click **System Library** on the main window's navigation menu. Note that for the dish input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Dish Stirling System.

For dish-Stirling systems, a complete set of default values for the parameters on the system pages (except costs) are stored in the system library. There is a set of default input values for two systems: SES and WGA-ADDS. When you choose one of these systems, SAM populates the input pages with parameters appropriate for the system. You can modify variable values on the input pages without affecting the values stored in the library.

Note: These systems are discussed in the thesis *Stirling Dish System Performance Prediction Model* (Fraser 2008) http://sel.me.wisc.edu/publications/theses/fraser08.zip (4.1 MB).

7.6.3 Solar Field

To view the Solar Field page, click **Solar Field** on the main window's navigation menu. Note that for the dish input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Dish Stirling System.

Contents

Overview

The parameters on the Solar Field page define the size of the solar field and the layout of the dish network. To explore the impact of these parameters on the system's costs and performance, change the value of the parameter.

The relevant sections of the thesis *Stirling Dish System Performance Prediction Model* (Fraser 2008) http://sel.me.wisc.edu/publications/theses/fraser08.zip (4.1 MB) are:

- 3.1 Parabolic Collector Model, p 63
- Appendix A: TRNSYS Parabolic Collector Model, p 152

Input Variable Reference

Field Layout

The solar field is assumed to be a rectangular field with collectors oriented north-south and east-west.

Number of Collectors North-South

Number of collectors oriented along north-south lines. Used to calculate the total number of collectors.

Number of Collectors East-West

Number of collectors oriented along east-west lines. Used to calculate the total number of collectors.

Number of Collectors

Total number of collectors in the field. Used to calculate the predicted system output, the shading factor, and piping distance for pumping loss calculation.

Collector Separation North-South (m)

Center-to-center distance between collectors along north-south lines. Used to calculate the solar field area, shading factor, and piping distance for pumping loss calculation.

Collector Separation East-West (m)

Center-to-center distance between collectors along east-west lines. Used to calculate the solar field area, shading factor, and piping distance for pumping loss calculation.

Total Solar Field Area (m^2)

The total ground area occupied by the collectors. Used in area-related cost calculations.

System Properties

Wind Stow Speed (m/s)

When the wind velocity from the weather file for the current hour is greater than or equal to this value, the concentrator moves into stow position to prevent wind damage. The solar power intercepted by the receiver is zero during this hour.

Total Solar Field Capacity (kWe)

Nominal electric output capacity of the solar field. Used in capacity-related cost calculations.

Array Shading Parameters

SAM uses the shading parameters to calculate the shading of the concentrator mirror by the dish components and by neighboring dish systems. SAM's approach to modeling shading is different from the Osborn approach described in the Fraser thesis.

Ground Slope, North-South (%)

Slope of the ground in percent (rise over run) along a north-south line. A positive slope indicates that for two dishes aligned north-south, the dish to the south is lower than the dish to the north. Used to calculate shading factor.

Ground Slope,East-West (%)

Slope of the ground in percent (rise over run) along a east-west line. A positive slope indicates that for two dishes aligned east-west, the dish to the east is lower than the dish to the west. Used to calculate shading factor.

Slot Gap Width (m)

Average width of the slot in the mirror perpendicular to the vertical support post. Used to calculate shading factor.

Slot Gap Height (m)

Average height of the slot in the mirror parallel to the vertical support post. Used to calculate shading factor.

Equations for Calculated Values

Number of Collectors

The total number of collectors is calculated based on the numbers of north-south and east-west oriented collectors.

$$N_{\mathrm{Coll}} = N_{\mathrm{Coll,N-S}} \cdot N_{\mathrm{Coll,E-W}}$$

Where,

N_{Coll}	Number of Collectors
$N_{Coll,N\text{-}S}$	Number of Collectors North-South
$N_{Coll,E\text{-}W}$	Number of Collectors East-West

Total Solar Field Area

The total solar field area is the product of the north-south and east west dish collector separation distances and the number of collectors.

$$A_{\mathrm{SF}} = d_{\mathrm{CollSep,N-S}} \cdot d_{\mathrm{CollSep,E-W}} \cdot N_{\mathrm{Coll}}$$

Where,

A_{SF} (m^2)	Total Solar Field Area
$d_{CollSep,N\text{-}S}$ (m)	Collector Separation North-South
$d_{CollSep,E\text{-}W}$ (m)	Collector Separation East-West
N_{Coll}	Number of Collectors

Total Capacity

The total solar field capacity is the product of the number of collectors and the engine nameplate capacity on the Stirling Engine page.

$$P_{\mathrm{SF}} = P_{\mathrm{Engine}} \cdot N_{\mathrm{Coll}}$$

Where,

P_{SF} (W)	Total Capacity
P_{Engine} (W)	Singe Unit Nameplate Capacity from the Stirling Engine page.
N_{Coll}	Number of Collectors

7.6.4 Collector

To view the Collector page, click **Collector** on the main window's navigation menu. Note that for the dish input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Dish Stirling System

Contents

- Overview describes the Collector page and lists references for more detailed information.

- [Input Variable Reference](#) describes the input variables on the Collector page.
- [Default Parameter Values](#) shows a table of default values for different systems.

Overview

The collector consists of parabolic mirrors, a support structure, and two-axis tracking system. The mirrors focus direct normal solar radiation on the aperture of the receiver. The receiver aperture size is typically optimized to maximize the quantity of reflected solar radiation that enters the receiver and minimize convection and radiation losses out of the aperture.

The relevant sections of the thesis *Stirling Dish System Performance Prediction Model* (Fraser 2008) http://sel.me.wisc.edu/publications/theses/fraser08.zip (4.1 MB) are:

- 2.1 Parabolic Concentrator, p 7
- 3.1 Parabolic Collector Model, p 63
- Appendix A: TRNSYS Parabolic Collector Model, p 150
- Appendix A: TRNSYS Parasitic Power Model, p 158

Input Variable Reference

The parameters on the Collector page are used to calculate the power output of the collector. The parameters are for a single dish collector, and are assumed to apply to each dish in the solar field.

Mirror Parameters

Projected Mirror Area (m^2)

Area of one concentrator's mirror projected on the aperture plane. Used to calculated the solar power intercepted by the receiver, and the shading factor.

Total Mirror Area (m^2)

Area of mirrored parabolic surface. Used to calculate collector diameter, which is used in the rim angle calculation and in the shading factor calculation.

Mirror Reflectance

The mirror reflectance input is the solar weighted specular reflectance. The solar-weighted specular reflectance is the fraction of incident solar radiation reflected into a given solid angle about the specular reflection direction. The appropriate choice for the solid angle is that subtended by the receiver as viewed from the point on the mirror surface from which the ray is being reflected. For parabolic troughs, typical values for solar mirrors are 0.923 (4-mm glass), 0.945 (1-mm or laminated glass), 0..906 (silvered polymer), 0.836 (enhanced anodized aluminum), and 0.957 (silvered front surface).

Performance

Insolation Cut In (W/m^2)

Direct normal radiation value above which the cooling system fan operates. Used to calculated parasitic losses.

Default Parameter Values

Table 13. Collector default parameter values.

Variable	SES	WGA	SBP	SAIC
Projected Mirror Area	87.7	41.2	56.7	113.5
Total Mirror Area	91.0	42.9	60	117.2
Insolation Cut In	200	275	250	375
Wind Stow Speed	16	16	16	16
Receiver Aperture Diameter for Reference Intercept Factor	0.184	0.14	0.15	0.38
Reference Intercept Factor	0.995	0.998	0.93	0.90
Reference Focal Length of Mirror	7.45	5.45	4.5	12.0

7.6.5 Receiver

To view the Receiver page, click **Receiver** on the main window's navigation menu. Note that for the dish input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Dish Stirling System.

Contents

Overview

The receiver absorbs thermal energy from the parabolic concentrator and transfers the energy to the working fluid of the Stirling engine. The receiver consists of an aperture and absorber. The receiver aperture is located at the parabolic concentrator's focal point. The current version of SAM models one receiver type, direct illumination receivers, in which solar radiation is directly absorbed by absorber tubes containing the working fluid. Direct illumination receivers are the receiver type most commonly used for dish-Stirling systems.

The relevant sections of the thesis *Stirling Dish System Performance Prediction Model* (Fraser 2008) http://sel.me.wisc.edu/publications/theses/fraser08.zip (4.1 MB) are:

- 2.2 Receiver, p 14
- 6.1 Modifying the Receiver Aperture Diameter, p 133
- 6.2 Receiver Cover versus no Cover, p 134

- Appendix A: TRNSYS Receiver Model, p 153

SAM uses the receiver parameters to calculate thermal losses from the receiver, which typically account for over 50% of the system's total losses. Other system losses include collector losses due to mirror reflectivity, receiver intercept losses, and Stirling engine losses. Receiver thermal losses are due to conduction, convection, and radiation:

- Conductive losses through the receiver housing.
- Natural convection from the cavity in the absence of wind.
- Forced convection in the presence of wind.
- Emission losses due to thermal radiation emitted from the receiver aperture.
- Radiation losses reflected off of the receiver cavity surfaces and out of the receiver through the aperture.

Input Variable Reference

Aperture

Receiver Aperture Diameter (m)

Diameter of the opening in the receiver that allows solar radiation to reach the absorber, and radiation and convection losses to escape the receiver cavity. Typical values range from 0.14 m to 0.20 m.

Insulation

Thickness (m)

Thickness of the receiver housing insulation. Typically about 75 mm. Used to calculate conduction losses.

Thermal Conductivity (W/m-K)

Thermal conductivity of the receiver cavity wall at 550 degrees Celsius. For high-temperature ceramic fiber, the value is 0.061 W/m-K. Used to calculate conduction losses.

Absorber

The absorber is a component of the receiver that absorbs solar radiation and transfers thermal energy to the Stirling engine.

Absorber Absorptance

The ratio of energy absorbed by the receiver absorber to the solar radiation reaching the absorber. Used to calculate radiation losses.

Absorber Surface Area (m^2)

Area of the absorber surface. Used to calculate the internal cavity area.

Cavity

The cavity parameters determine the cavity's geometry. The internal cavity area is the sum of the cavity wall surface area and absorber area and is used to calculate radiation, conduction and convection losses.

Cavity Absorptance

The ratio of energy absorbed by the cavity wall to radiation reaching it. Used to calculated reflected radiation losses.

Cavity Surface Area (m^2)

Area of the cavity wall surface. Used to calculate the internal cavity area.

Internal diameter of the Cavity Perp. to Aperture (m)

Average diameter of the cavity perpendicular to the receiver aperture. Used to calculate the internal cavity area.

Internal Cavity Pressure with Aperture covered (kPa)

Applies only to receivers with a cover. Used to calculate convection losses.

Internal Depth of the Cavity Perpendicular to the Aperture (m)

Equivalent to the cavity's characteristic length, which is used to calculate convection losses.

Default Parameter Values

Table 14. Receiver default parameter values.

Variable	SES	WGA	SBP	SAIC
Absorber Absorptance	0.90	0.90	0.90	0.90
Absorber Surface Area	0.6	0.15	0.15	0.8
Cavity Wall Absorptance	0.6	0.6	0.6	0.6
Cavity Wall Surface Area	0.6	0.15	0.15	0.8
Internal Diameter of the Cavity Perpendicular to the Receiver Aperture	0.46	0.35	0.37	0.5
Internal Depth of the Cavity Perpendicular to the Aperture	0.46	0.35	0.37	0.5
Receiver Insulation Thickness	0.075	0.075	0.075	0.075
Insulation Thermal Conductivity	0.06	0.06	0.06	0.06
Delta Temp. for DIR Receiver	90	70	70	90

7.6.6 Stirling Engine

To view the Stirling Engine page, click **Stirling Engine** on the main window's navigation menu. Note that for the trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Dish Stirling System.

Contents

- Overview describes the Stirling Engine page and lists references for more detailed information.
- Input Variable Reference describes the input variables on the Stirling Engine page.

➢ Default Parameter Values shows a table of default values for different systems.

Overview

The Stirling engine converts heat from the receiver's absorber to mechanical power that drives an electric generator.

The relevant sections of the thesis *Stirling Dish System Performance Prediction Model* (Fraser 2008) http://sel.me.wisc.edu/publications/theses/fraser08.zip (4.1 MB) are:

- 2.3 Stirling Engine Design, p 29
- 2.4 Stirling Engine Analysis Methods, p 40
- 3.3 Stirling Engine/System Models, p 82
- 6 TRNSYS Model Performance Predictions, p 132
- Appendix A: TRNSYS Stirling Engine and Generator Model, p 156

The Stirling engine model is based on the Beale curve-fit equation with temperature correction described in Fraser (2008). The model calculates the average hourly engine power output in Watts as a function of the Beale curve-fit equation, pressure curve-fit equation, the engine displacement and operating speed, and expansion space (heater head) temperatures. The Beale curve-fit equation calculates the engine's gross output power as a function of the input power calculated by the collector and receiver models. SAM determines the compression space temperature from the ambient temperatures in the weather data file.

Input Variable Reference

Estimated Generation

Single Unit Nameplate Capacity (kW)

The nominal electrical power output of the engine-generator set for a single dish-Stirling unit. Used for capacity-related cost calculations.

Engine Parameters

Heater Head Set Temperature (K)

Expansion space temperature set point.

Heater Head Lowest Temperature

The expansion space temperature in an engine with multiple cylinders of the heater head with the lowest temperature. The heater head temperature is equivalent to the expansion space temperature.

Engine Operating Speed (rpm)

The rotational speed of the engine drive shaft. Used to calculate the engine output power.

Displaced Engine Volume (m^3)

The volume displaced by the pistons. Used to calculate the engine output power.

Beale Curve Fit Coefficients

The Beale numbers are a set of coefficients for the Beale curve-fit equation that describes the engine's power output as a function of its input power and the engine pressure.

Pressure Curve Fit Coefficients

The pressure curve-fit equation expresses the engine pressure as a function of engine input power for a constant volume system.

Default Parameter Values

Table 15. Stirling engine default parameter values.
The following parameter values are based on values developed for the model. The SBP and SAIC engines are not included in the SAM standard library and require a different set of equations (see Fraser 35).

Variable	SES	WGA	SBP	SAIC
Heater Head Set Temperature	993	903	903	993
Heater Head Lowest Temperature	973	903	903	973
Engine Operating Speed	1800	1800	1800	2200
Displaced Engine Volume	3.80×10^{-4}	1.60×10^{-4}	1.60×10^{-4}	4.80×10^{-4}
Beale Constant Coefficient	4.247×10^{-2}	8.50686×10^{-2}	$-1{,}82451 \times 10^{-3}$	-1.6×10^{-2}
Beale First-order Coefficient	1.682×10^{-5}	1.94116×10^{-5}	2.60289×10^{-5}	1.5×10^{-5}
Beale Second-order Coefficient	-5.105×10^{-10}	-3.18449×10^{-10}	-4.68164×10^{-10}	-3.50×10^{-10}
Beale Third-order Coefficient	7.07260×10^{-15}	0	0	3.85×10^{-15}
Beale Fourth-order Coefficient	-3.586×10^{-20}	0	0	-1.6×10^{-20}
Pressure Constant Coefficient	6.58769×10^{-1}	-7.36342×10^{-1}	-2.00284×10^{-2}	3.47944×10^{-5}
Pressure First-order Coefficient	2.34963×10^{-4}	3.6416×10^{-4}	3.52522×10^{-4}	5.26329×10^{-9}

7.6.7 Parasitics

To view the Parasitics Costs page, click **Parasitics** on the main window's navigation menu. Note that for the dish input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Dish Stirling System.

Contents

Overview

The input variables on the Parasitics page are used to calculate the compression space temperature and the electrical power consumption of pumps, cooling fans, and tracking controls.

The relevant sections of the thesis *Stirling Dish System Performance Prediction Model* (Fraser 2008) http://sel.me.wisc.edu/publications/theses/fraser08.zip (4.1 MB) are:

- 2.5 Cooling System, p 55
- 3.4 Cooling System Analysis for Total System Optimization, p 92
- Appendix A: TRNSYS Parasitic Power Model, p 158

Input Variable Reference

Parasitic Parameters

Control System Parasitic Power, Avg. (W)

Average power required by the tracking control system.

Cooling System Pump Speed (rpm)

Cooling fluid pump operating speed. Used to calculated parasitic losses due to cooling fluid pumping.

Cooling System Fan Speed 1 (rpm)

Fan operating speed when the cooling fluid temperature is less than the fan speed 2 cut-in temperature below.

Cooling System Fan Speed 2 (rpm)

Fan operating speed when the cooling fluid temperature is greater than the fan speed 2 cut-in and less than fan speed 3 cut-in temperature below.

Cooling System Fan Speed 3 (rpm)

Fan operating speed when the cooling fluid temperature is greater than fan speed 3 cut-in temperature below.

Cooling Fluid Temp. for Fan Speed 2 Cut-In (°C)

Cooling fluid temperature set point. Used to determine fan operating speeds.

Cooling Fluid Temp. for Fan Speed 3 Cut-In (°C)

Cooling fluid temperature set point. Used to determine fan operating speeds.

Cooling Fluid Type

Fluid used in the cooling system. Options are water, 50% ethylene glycol (EG), 25% ethylene glycol, 40% propylene glycol (PG), and 40% propylene glycol. Percentages are by volume.

Cooler Effectiveness

Used to calculate working fluid temperatures in the cooling system as part of the compression space temperature calculation.

Radiator Effectiveness

Used to calculate cooling fluid temperature at the cooling system outlet as part of the compression space temperature calculation.

7.6.8 Reference Inputs

To view the Reference Inputs page, click **Reference Inputs** on the main window's navigation menu. Note that for the dish input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Dish Stirling System.

Contents

- Overview describes the Reference Inputs page and lists references for more detailed information.
- Input Variable Reference describes the input variables on the Reference Inputs page.
- Parasitic Variable Reference Conditions lists the reference conditions for different systems.

Overview

SAM uses the reference condition parameters in an iterative process to calculate the total collector error for a given set of values for the aperture diameter, focal length, and collector diameter. Once the collector error is calculated, that value can be used to calculate a new intercept factor for different aperture diameters (See Fraser, p 150-151).

Input Variable Reference

Collector Reference Condition Inputs

Intercept Factor

Fraction of energy reflected from the parabolic mirror that enters the receiver aperture. The intercept factor can be increased by increasing the concentration ratio or by increasing the size of the aperture. Intercept factors typically range between 0.94 and 0.99.

Focal Length of Mirror (m)

Parabolic mirror focal length.

Parasitic Variable Reference Conditions

The reference condition parameters given in the table below and as user inputs in SAM are used in the pump law calculations that are part of the parasitic loss equations.

Variable	SES	WGA	SBP	SAIC
Pump Parasitic Power	150	100	175	300
Pump Speed (rpm)	1800	1800	1800	1800
Cooling Fluid Type	50% EG	50% EG	water	50% EG
Cooling Fluid Temperature (K)	288	288	288	288
Cooling Fluid Volumetric Flow Rate (gal/min)	9	7.5	7.5	12
Cooling System Fan Test Power (W)	1000	410	510	2500
Cooling System Fan Test Speed (rpm)	890	890	890	850
Fan Air Density (kg/m3)	1.2	1.2	1.2	1.2
Fan Volumetric Flow Rate (CFM)	6000	4000	4500	10000

7.7 Generic Solar System

The generic solar system model allows you to model a system that consists of a solar field, power block with a conventional steam turbine, and optional thermal energy storage system. The model represents the solar field using a set of optical efficiency values for different sun angles and can be used for any solar technology that uses solar energy to generate steam for electric power generation.

For a general description of the model, see Overview.

The input pages for the Generic Solar System model are:

- Location and Resource
- Generic Solar System Costs
- Solar Field
- Power Block
- Thermal Storage

7.7.1 Generic Solar Overview

The generic solar system model allows you to model a system that consists of a solar field, power block with a conventional steam turbine, and optional thermal energy storage system. The model represents the solar field using a set of optical efficiency values for different sun angles and can be used for any solar technology that uses solar energy to generate steam for electric power generation.

To learn more about the model's implementation, you can explore the source code written in FORTRAN for the generic solar system model in the following folder of your SAM installation folder (c:\SAM\SAM 2014.1.14 by default): C:\exelib\trnsys\source. The generic solar system model files are:

- sam_mw_gen_type260.f90
- sam_mw_gen_module.f90

The input pages for the Generic Solar System model are:

- Location and Resource
- Generic Solar System Costs
- Solar Field
- Power Block
- Thermal Storage

7.7.2 Solar Field

Contents

- Input Variable Reference describes the input variables and options on the Solar Field page.
- Sizing the Solar Field describes how to choose between Option 1 and Option 2, choose a field layout, choose an irradiation at design value, and optimize the solar multiple for systems with and without storage.

Input Variable Reference

Solar Field Optical Efficiency Data

The solar position table option allows you to specify optical efficiency of the solar field as a function of solar azimuth and zenith angles. SAM uses a solar azimuth angle convention where true North is equal to -180/+180° and South equals 0°. The solar zenith angle is zero when the sun is directly overhead and 90° when the sun is at the horizon.

The solar position may contain any number of rows and columns, but should contain enough information to fully define the performance of the solar field at all sun positions for which the field will operate. The table must contain more than one row and column.

SAM uses linear interpolation to estimate efficiency values for solar positions between those specified on the table.

Import

Import a table from a text or data file. The file can contain values separated by comma, space, or tab characters, but must be formatted according to the following rules:

- The first row in the file specifies the angles for the solar azimuth (for the Solar position table) or collector transversal incidence (for the Collector incidence angle table). The first entry of this row should be blank.
- Each additional row specifies optical efficiency for a specific zenith angle (for the Solar position table) or longitudinal incidence angle (for the Collector incidence angle table). The first entry of the row must be the zenith or longitudinal incidence angle corresponding to the optical efficiency entries in that row.
- The rows of the table should be sorted according to zenith/longitudinal incidence angle from lowest to highest.

An example tab-delimited table is as follows, where numbers in bold correspond to the solar zenith (row headers) and azimuth (column headers) angles:

	-180	**90**	**0**	**90**	**180**
0	1.0	1.0	1.0	1.0	1.0
30	0.95	0.98	0.99	0.98	0.95
60	0.60	0.70	0.75	0.70	0.60
90	0.0	0.0	0.0	0.0	0.0

Note that SAM automatically sizes the table on the Collector and Receiver page to match the size of the array that is being imported.

Export

Export the optical efficiency table on the Collector and Receiver page to a text file.

Copy

Copy the optical efficiency table on the Collector and Receiver page to the clipboard for transfer to an optical efficiency table in another case or to other text applications.

Paste

Paste an optical efficiency table from another SAM case or from a text file into the active case.

Rows

Specify the number of desired rows in the table.

Cols

Specify the number of desired columns in the table.

Interpolate table

Choose this option if you want SAM to use interpolation to calculate radiation values for points between those included in the table.

Irradiation basis

Determines the column of data that SAM reads from the weather file.

Design Point Parameters

Solar Multiple

The field aperture area expressed as a multiple of the aperture area required to operate the power cycle at its design capacity. See Sizing the Solar Field for details.

Solar field design output (MWt)

The thermal energy delivered by the solar field under design conditions at the given solar multiple. This value is calculated in the interface as the function of the solar multiple, the Reference conversion efficiency on the Power Block page, and the Design gross output on the Power Block page, as follows:

$$\dot{Q}_{sf,des} = \frac{W_{pb,des}}{\eta_{des}} \cdot SM$$

Ambient temp at design (°C)

The design point ambient temperature (dry-bulb), used to calculate solar field thermal efficiency and the aperture area required to drive the power cycle at its design capacity.

Solar resource at design (W/m²)

The design point direct normal radiation value, used in solar multiple mode to calculate the aperture area required to drive the power cycle at its design capacity.

Stow angle (degrees)

The collector angle during the hour of stow. A stow angle of zero for a northern latitude is vertical facing east, and 180 degrees is vertical facing west. Default is 170 degrees.

Deploy angle (degrees)

The collector angle during the hour of deployment. A deploy angle of zero for a northern latitude is vertical facing due east. Default is 10 degrees.

Estimated Solar Field Area (m²)

The total solar energy collection area of the solar field in square meters.

Estimated Solar Field Area = (Solar Field Design Output + Thermal Loss at Design)
/ Total Optical Efficiency × 1,000,000
/ Solar Resource at Design

Efficiency Derates

Peak optical efficiency

The maximum value of the optical efficiency values in the Solar Field Optical Efficiency Data table.

Cleanliness factor

A derating factor to account for optical losses by soiling on the mirror surface or other losses.

General optical derate

Accounts for reduction in absorbed radiation caused by general optical errors or other unaccounted error sources.

Total optical efficiency

The product of the three optical efficiency factors.

Generalized Thermal Losses

Reference thermal loss fraction

The fraction of thermal power generated by the solar field that is lost to thermal losses at design. The heat loss calculation during the annual hourly performance run multiplies this value by the resulting values of the heat loss correction polynomials to obtain the total solar field thermal efficiency. The thermal losses from the solar field are evaluated according to the following relationship, where the various F_{hl} coefficients are evaluated according to the descriptions provided below.

$$\dot{Q}_{hl} = \dot{Q}_{hl,ref} \frac{I_{bn}}{I_{bn,des}} F_{hl,I_{bn}} F_{hl,T_{amb}} F_{hl,V_{wind}}$$

where $Q_{hl,ref}$ is the reference thermal loss from the solar field at design.

Irradiation thermal loss adjustment

This polynomial adjust the thermal loss fraction in the solar field as a function of the solar irradiation available during the current time step of the performance simulation. The polynomial is evaluated to determine the sensitivity of thermal losses to irradiation as follows:

$$F_{hl,I_{bn}} = C_0 + C_1 \cdot \left(\frac{I_{bn}}{I_{bn,des}}\right) + C_2 \cdot \left(\frac{I_{bn}}{I_{bn,des}}\right)^2 + C_3 \cdot \left(\frac{I_{bn}}{I_{bn,des}}\right)^3$$

where Ibn is the solar irradiation during the current time step and Ibn,des is the design-point solar irradiation from the Solar resource at design input on the Solar Field page.

Ambient temp thermal loss adjustment

This polynomial adjusts the thermal loss fraction in the solar field as a function of the ambient dry-bulb temperature in degrees Celsius. The Reference thermal loss fraction is multiplied by the result of the following polynomial:

$$F_{hl,T_{amb}} = C_0 + C_1 \cdot \Delta T_{amb} + C_2 \cdot \Delta T_{amb}^2 + C_3 \cdot \Delta T_{amb}^3$$

where

$$\Delta T_{amb} = T_{amb} T_{amb} - T_{amb,des}$$

or the ambient temperature for the current time step of the simulation minus the ambient dry-bulb temperature at design.

Wind speed thermal loss adjustment

This polynomial adjusts the thermal loss fraction in the solar field as a function of the wind speed during the current time step of the performance simulation. The result of the evaluated wind speed adjustment polynomial multiplies the Reference thermal loss fraction and other correction polynomials to determine the total solar field efficiency. The polynomial is evaluated as follows:

$$F_{hl,V_{wind}} = C_0 + C_1 \cdot V_{wind} + C_2 \cdot V_{wind}^2 + C_3 \cdot V_{wind}^3$$

Thermal loss at design

The calculated thermal losses at design conditions, equal to the product of the **Reference thermal loss fraction** and the **Solar field design output**. SAM calculates actual thermal losses during simulation runs using on the design-point thermal losses and the results of the thermal loss correction polynomials described above. The design thermal losses are used to size the aperture area of the solar field that is required to drive the power cycle.

Sizing the Solar Field

Sizing the solar field of a parabolic trough system in SAM involves determining the optimal solar field aperture area for a system at a given location. In general, increasing the solar field area increases the system's electric output, thereby reducing the project's LCOE. However, during times there is enough solar resource, too large of a field will produce more thermal energy than the power block and other system components can handle. Also, as the solar field size increases beyond a certain point, the higher installation and operating costs outweigh the benefit of the higher output.

An optimal solar field area should:

- Maximize the amount of time in a year that the field generates sufficient thermal energy to drive the power block at its rated capacity.
- Minimize installation and operating costs.
- Use thermal energy storage and fossil backup equipment efficiently and cost effectively.

The problem of choosing an optimal solar field area involves analyzing the tradeoff between a larger solar field that maximizes the system's electrical output and project revenue, and a smaller field that minimizes installation and operating costs.

The levelized cost of energy (LCOE) is a useful metric for optimizing the solar field size because it includes the amount of electricity generated by the system, the project installation costs, and the cost of operating and maintaining the system over its life. Optimizing the solar field involves finding the solar field aperture area that results in the lowest LCOE. For systems with thermal energy storage systems, the optimization involves finding the combination of field area and storage capacity that results in the lowest LCOE.

Option 1 and Option 2

SAM provides two options for specifying the solar field aperture area: Option 1 (solar multiple) allows you to specify the solar field area as a multiple of the power block's rated capacity (design gross output), and Option 2 (field aperture) allows you to specify the solar field aperture area as an explicit value in square meters.

- Option 1: You specify a solar multiple, and SAM calculates the solar field aperture area required to meet power block rated capacity.
- Option 2: You specify the aperture area independently of the power block's rated capacity.

If your analysis involves a known solar field area, you should use Option 2 to specify the solar field aperture area explicitly.

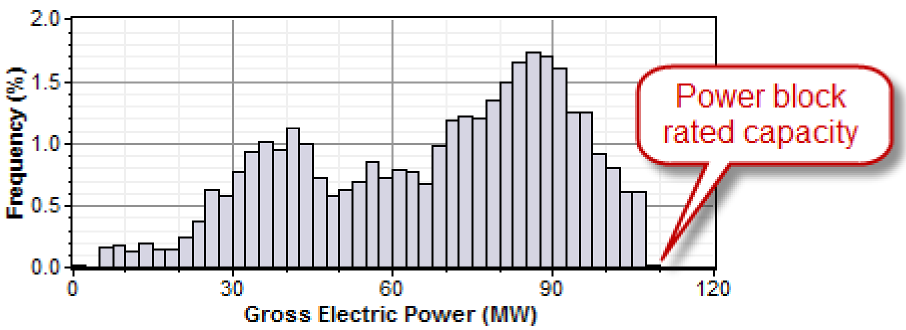
If your analysis involves optimizing the solar field area for a specific location, or choosing an optimal combination of solar field aperture area and thermal energy storage capacity, then you should choose Option 1, and follow the procedure described below to size the field.

Solar Multiple

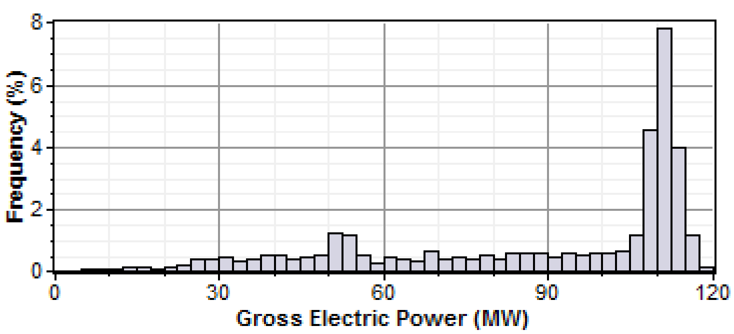
The solar multiple makes it possible to represent the solar field aperture area as a multiple of the power block rated capacity. A solar multiple of one (SM=1) represents the solar field aperture area that, when exposed to solar radiation equal to the design radiation value (irradiation at design), generates the quantity of thermal energy required to drive the power block at its rated capacity (design gross output), accounting for thermal and optical losses.

Because at any given location the number of hours in a year that the actual solar resource is equal to the design radiation value is likely to be small, a solar field with SM=1 will rarely drive the power block at its rated capacity. Increasing the solar multiple (SM>1) results in a solar field that operates at its design point for more hours of the year and generates more electricity.

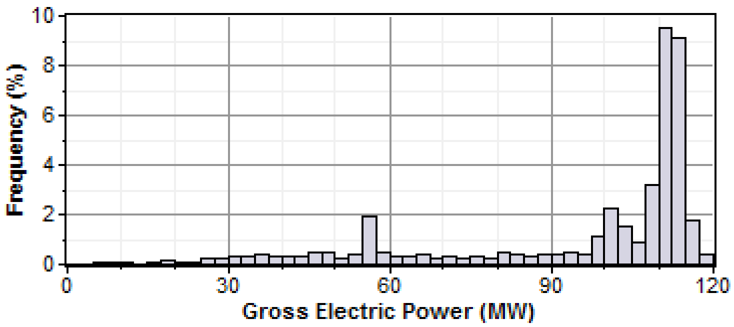
For example, consider a system with a power block design gross output rating of 111 MW and a solar multiple of one (SM=1) and no thermal storage. The following frequency distribution graph shows that the power block never generates electricity at its rated capacity, and generates less than 80% of its rated capacity for most of the time that it generates electricity:



For the same system with a solar multiple chosen to minimize LCOE (in this example SM=1.5), the power block generates electricity at or slightly above its rated capacity almost 15% of the time:



Adding thermal storage to the system changes the optimal solar multiple, and increases the amount of time that the power block operates at its rated capacity. In this example, the optimal storage capacity (full load hours of TES) is 3 hours with SM=1.75, and the power block operates at or over its rated capacity over 20% of the time:



Note. For clarity, the frequency distribution graphs above exclude nighttime hours when the gross power output is zero.

Reference Weather Conditions for Field Sizing

The design weather conditions values are reference values that represent the solar resource at a given location for solar field sizing purposes. The field sizing equations require three reference condition variables:

- Ambient temperature
- Direct normal irradiance (DNI)
- Wind velocity

The values are necessary to establish the relationship between the field aperture area and power block rated capacity for solar multiple (SM) calculations.

Note. The design values are different from the data in the weather file. SAM uses the design values to size the solar field before running simulations. During simulations, SAM uses data from the weather file you choose on the Location and Resource page.

The reference ambient temperature and reference wind velocity variables are used to calculate the design heat losses, and do not have a significant effect on the solar field sizing calculations. Reasonable values for those two variables are the average annual measured ambient temperature and wind velocity at the project location. For the physical trough model, the reference temperature and wind speed values are hard-coded and cannot be changed. The linear Fresnel and generic solar system models allow you to specify the reference ambient temperature value, but not the wind speed. The empirical trough model allows you to specify both the reference ambient temperature and wind speed values.

The reference direct normal irradiance (DNI) value, on the other hand, does have a significant impact on the solar field size calculations. For example, a system with reference conditions of 25°C, 950 W/m^2, and 5 m/s (ambient temperature, DNI, and wind speed, respectively), a solar multiple of 2, and a 100 MWe power block, requires a solar field area of 871,940 m^2. The same system with reference DNI of 800 W/m^2 requires a solar field area of 1,055,350 m^2.

In general, the reference DNI value should be close to the maximum actual DNI on the field expected for the location. For systems with horizontal collectors and a field azimuth angle of zero in the Mohave Desert of the United States, we suggest a design irradiance value of 950 W/m2. For southern Spain, a value of 800 W/m2 is reasonable for similar systems. However, for best results, you should choose a value for your specific location using one of the methods described below.

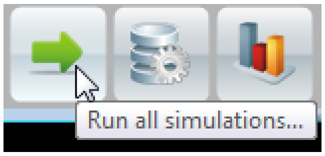
Linear collectors (parabolic trough and linear Fresnel) typically track the sun by rotating on a single axis, which means that the direct solar radiation rarely (if ever) strikes the collector aperture at a normal angle.

Consequently, the DNI incident on the solar field in any given hour will always be less than the DNI value in the resource data for that hour. The cosine-adjusted DNI value that SAM reports in simulation results is a measure of the incident DNI.

Using too low of a reference DNI value results in excessive "dumped" energy: Over the period of one year, the actual DNI from the weather data is frequently greater than the reference value. Therefore, the solar field sized for the low reference DNI value often produces more energy than required by the power block, and excess thermal energy is either dumped or put into storage. On the other hand, using too high of a reference DNI value results in an undersized solar field that produces sufficient thermal energy to drive the power block at its design point only during the few hours when the actual DNI is at or greater than the reference value.

To choose a reference DNI value:

1. Choose a weather file on the Location and Resource page.
2. Enter values for collector tilt and azimuth.
3. For systems with storage, specify the storage capacity and maximum storage charge rate defined on the Thermal Storage page.
4. Click run all simulations, or press Ctrl-G.



5. On the Results page, click Time Series.
6. On the Time Series tab, click Zoom to Fit (at the bottom of the input page).

Method 1: Maximum Cosine-adjusted DNI

7. Clear all of the check boxes and check DNI-cosine effect product (W/m2) variable.
8. Read the maximum annual value from the graph, and use this value for the reference DNI.

Method 2: Minimize "Dumped" Energy

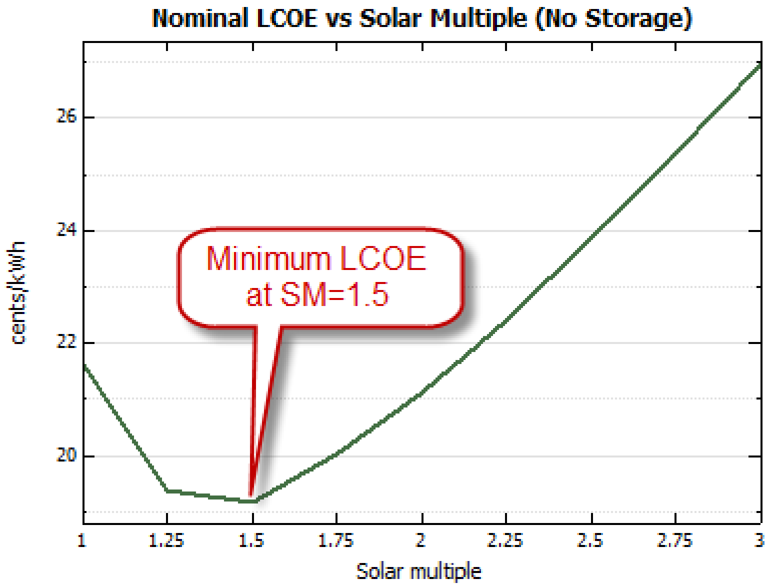
7. Clear all of the check boxes and check the dumped thermal energy variable(s).
8. If the amount of dumped thermal energy is excessive, try a lower value for the reference DNI value and run simulations again until the quantity of dumped energy is acceptable.

Optimizing the Solar Multiple

Representing the solar field aperture area as a solar multiple (Option 1) makes it possible to run parametric simulations in SAM and create graphs of LCOE versus solar multiple like the ones shown below. You can use this type of graph to find the optimal solar multiple.

For a parabolic trough system with no storage, the optimal solar multiple is typically between 1.4 and 1.5.

The graph shown below is for a system with no storage in Blythe, California, the optimal solar multiple is 2, meaning that the solar field aperture area should be chosen to be twice the area required to drive the power cycle at its rated capacity:

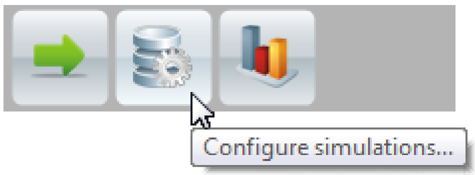


Because the optimal solar multiple depends on the LCOE, for accurate results, you should specify all of the project costs, financing, and incentive inputs in addition to the inputs specifying the physical characteristics of the solar field, power cycle and storage system before the optimization. However, for preliminary results, you can use default values for any variables for which you do not have values.

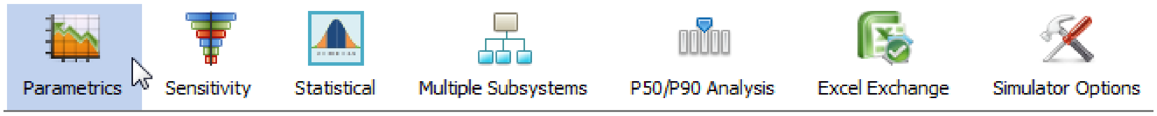
The following instructions describe the steps for optimizing the solar multiple for a preliminary system design that mostly uses default values except for a few key variables. This example is for a 50 MW system, but you can use the same procedure for a system of any size.

To optimize the solar field with no storage:

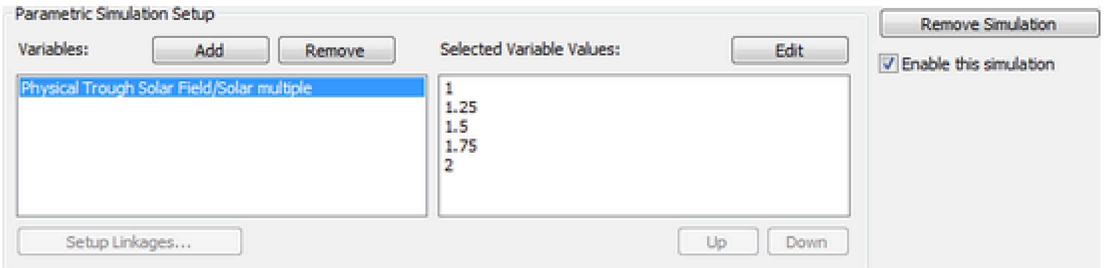
1. Create a new physical trough project with Utility IPP financing.
2. On the Location and Resource page, choose a location.
3. Follow the instructions above to find an appropriate irradiation at design value for your weather data. Use zero for both the collector tilt and azimuth variables.
4. On the Power Cycle page, for Design gross output, type 55 to specify a power block with a rated net electric output capacity of 50 MW (based on the default net conversion factor of 0.9).
5. On the Thermal Storage page, for **Full load hours of TES**, type 0 to specify a system with no storage.
6. On the Solar Field page, under **Solar Field Parameters**, choose **Option 1** (solar multiple) if it is not already active.
7. Click Configure simulations.



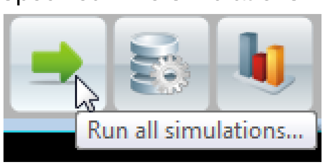
8. Click **Parametrics**.



9. Click **Add Parametric Simulation**.
10. Click **Add** to open the Choose Parametrics window.
11. In the Search box, type "solar multiple."
12. Check **Solar Multiple**.
13. Click **Edit** to open the Edit Parametric Values window.
14. Type the following values: Start Value = 1, End Value = 2, Increment = 0.25.
15. Click **Update**. The parametric simulation setup options should look like this:
16. Click **OK**.



17. Click Run all simulations. SAM will run a simulation for each of the 5 solar multiple values you specified. The simulations may take a few minutes to run.



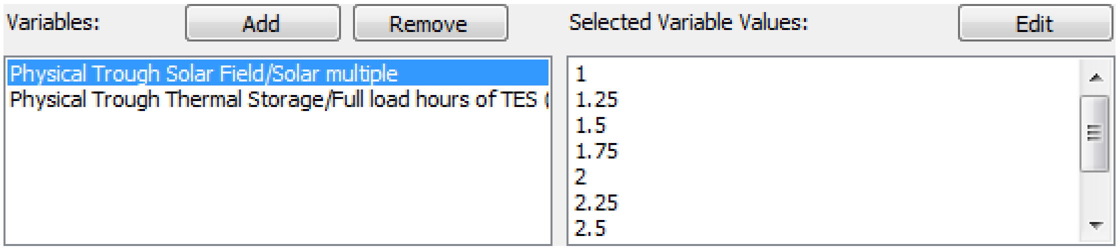
18. On the Results page, click **Add a new graph**.
19. Choose the following options: **Choose Simulation** = Parametric Set 1, **X Value** = {Solar Multiple}, **Y1 Values** = LCOE Nominal, **Graph Type** = Line Plot
20. Click **Accept**. SAM should display a graph that looks similar to the "Nominal LCOE vs Solar Multiple (No Storage)" graph above.
21. On the graph, find the solar multiple value that results in the lowest LCOE. If the minimum LCOE occurs at either end of the graph, you may need to add more values to the solar multiple parametric variable to find the optimal value.

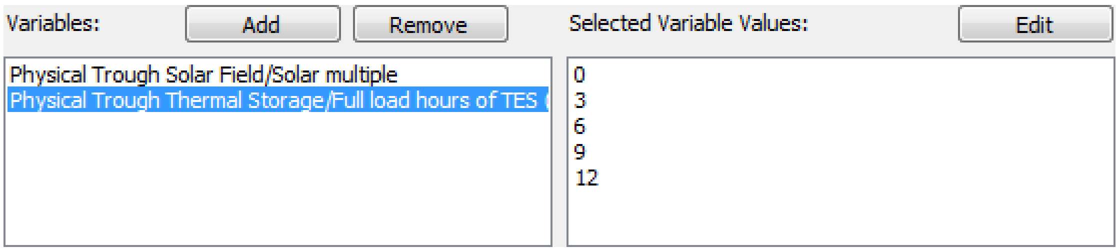
Optimal Solar Multiple for a System with Storage

Note. The linear Fresnel model in the current version of SAM does not include a storage option.

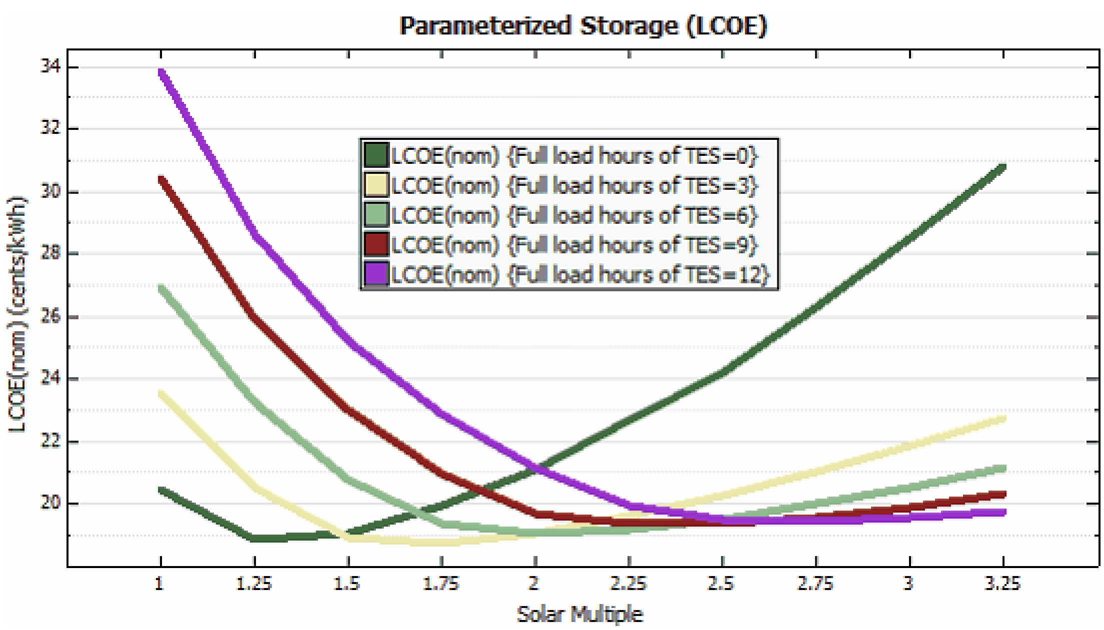
Adding storage to the system introduces another level of complexity: Systems with storage can increase system output (and decrease the LCOE) by storing energy from an larger solar field for use during times when the solar field output is below the design point. However, the thermal energy storage system's cost and thermal losses also increase the LCOE.

To find the optimal combination of solar multiple and storage capacity for systems with thermal storage, run a parametric analysis as described above, but with two parametric variables instead of one: Solar multiple and Full load hours of TES (storage capacity). The parametric setup options should look similar to this:





After running simulations, you will be able to create a graph like the one below that allows you to choose the combination of solar multiple and storage capacity that minimizes the LCOE. For example, the following graph shows that for a system in Blythe, California, the optimal combination of solar multiple and thermal storage capacity is SM = 1.75 and Hours of TES = 3.



Each line in the graph represents a number of hours of thermal energy storage from the list we saw in the list of parametric values for the Equivalent Full Load Hours of TES variable: 0, 3, 6, 9, and 12 hours of storage.

For the no storage case (the dark green line, zero hours of storage), the lowest levelized cost of energy occurs at a solar multiple of 1.25. For a given storage capacity, as the solar multiple increases, both the area-dependent installation costs electricity output increase. The interaction of these factors causes the levelized cost of energy to decrease as the solar multiple increases from 1, but at some point the cost increase overwhelms the benefit of the increased electric energy output, and the levelized cost of energy begins to increase with the solar multiple.

Simplified Steps for Optimizing the Solar Field

If you are performing a preliminary analysis or learning to use SAM, you can use the following simplified steps, using default values for most of the inputs:

1. Choose a location on the Location and Resource page.
2. Specify the power cycle capacity on the Power Cycle page.
3. Choose an irradiation at design value on the Solar Field page.
4. Optimize the solar field aperture area using Option 1.

Overall Steps for Optimizing the Solar Field

1. Choose a location on the Location and Resource page.
2. Specify the power cycle capacity and other characteristics on the Power Cycle page.
3. Specify characteristics of the solar field components on the Receivers (HCEs) and Collectors (SCAs) pages.
4. If the system includes thermal energy storage, specify its characteristics on the Thermal Storage page. (Note. For systems with storage, use the optimization process in Step 8 below to find the optimal storage capacity.)
5. Define the project costs on the Trough System Costs page.
6. Configure a single loop and specify solar field heat transfer fluid (HTF) properties on the Solar Field page.
7. Specify the collector orientation on the Solar Field page.
8. Choose an irradiation at design value on the Solar Field page.
9. Either optimize the solar field aperture area using Option 1, or specify the solar field area explicitly using Option 2 on the Solar Field page.
10. Refine your analysis by adjusting other model parameters.

7.7.3 Power Block

Capacity

Design gross output (MWe)

The power cycle's design output, not accounting for parasitic losses. SAM uses this value to size system components, such as the solar field area when you use the solar multiple to specify the solar field size.

Estimated gross to net conversion factor

An estimate of the ratio of the electric energy delivered to the grid to the power cycle's gross output. SAM uses the factor to calculate the system's nameplate capacity for capacity-related calculations.

Estimated net output at design (MWe)

The power cycle's nominal capacity, calculated as the product of the design gross output and estimated gross to net conversion factor. SAM uses this value for capacity-related calculations, including the estimated total cost per net capacity value on the System Costs page, capacity-based incentives on the Cash Incentives page, and the capacity factor reported in the results.

Estimated Net Output at Design (MWe) = Design Gross Output (MWe) × Estimated Gross to Net Conversion Factor

Conversion

Note. The generic solar system model's steam turbine model is based on the empirical parabolic trough model's power block model. For a description of how SAM uses the part-load and temperature adjustment coefficients, see Power Block Simulation Calculations.

Reference conversion efficiency

Total thermal to electric efficiency of the reference turbine at design. Used to calculate the design turbine thermal input and required solar field aperture area.

Max over design operation

The turbine's maximum output expressed as a fraction of the design turbine thermal input. Used by the dispatch module to set the power block thermal input limits. In cases where the normalized thermal power delivered to the power block by the solar field exceeds this fraction, the field will dump excess energy.

Minimum load

The turbine's minimum load expressed as a fraction of the design turbine thermal input. Used by the dispatch module to set the power block thermal input limits. In cases where the solar field, thermal storage, and/or fossil backup system are unable to produce enough energy to meet this fractional requirement, the power cycle will not produce electricity.

Power cycle startup energy

Hours of equivalent full-load operation of the power cycle required to bring the system to operating temperature after a period of non-operation. Used by the dispatch module to calculate the required start-up energy.

Boiler LHV Efficiency

The back-up boiler's lower heating value efficiency. Used by the power block module to calculate the quantity of gas required by the back-up boiler.

Power cycle design ambient temperature

The ambient temperature at which the power cycle conversion efficiency is equal to the reference conversion efficiency. The temperature corresponds to either the wet-bulb or dry-bulb temperature, depending on the value selected by the user in the Temperature correction mode list. The temperature is used in the Temperature adjustment polynomial in the Parasitics group on the Power Block page to determine cycle conversion efficiency.

Part load efficiency adjustment

Coefficients for the turbine thermal-to-electric efficiency polynomial equation. This polynomial is used to adjust the cycle conversion efficiency as the thermal load into the power cycle varies from its design-point value. The resulting value from the evaluated polynomial multiplies the reference conversion efficiency, where the polynomial is formulated as follows:

$$F_{\eta,load} = C_0 + C_1 \cdot \left(\frac{\dot{Q}_{pb}}{\dot{Q}_{pb,des}}\right) + C_2 \cdot \left(\frac{\dot{Q}_{pb}}{\dot{Q}_{pb,des}}\right)^2 + C_3 \cdot \left(\frac{\dot{Q}_{pb}}{\dot{Q}_{pb,des}}\right)^3 + C_4 \cdot \left(\frac{\dot{Q}_{pb}}{\dot{Q}_{pb,des}}\right)^4$$

Temperature efficiency adjustment

Factors for polynomial equation adjusting power cycle efficiency based on the difference between the power cycle design temperature and ambient temperature (either wet bulb or dry bulb temperature from the weather file, depending on the option you choose for Temperature Correction Mode.) The polynomial is formulated as follows:

$$F_{\eta,temp} = C_0 + C_1 \cdot (T_{amb} - T_{pb,des}) + C_2 \cdot (T_{amb} - T_{pb,des})^2 + C_3 \cdot (T_{amb} - T_{pb,des})^3 + C_4 \cdot (T_{amb} - T_{pb,des})^4$$

where T_{amb} is the wet or dry bulb temperature, depending on the **Temperature Correction Mode** selection.

Temperature Correction Mode

In the dry bulb mode, SAM calculates a temperature correction factor to account for cooling tower losses based on the ambient temperature from the weather data set. In wet bulb mode, SAM calculates the wet bulb temperature from the ambient temperature and relative humidity from the weather data.

Parasitics

Fixed parasitic load (MWe/MWcap)

A fixed hourly loss calculated as a fraction of the power block nameplate capacity.

Production based parasitic (MWe/MWe)

A variable hourly loss calculated as a fraction of the system's hourly electrical output. The total production-based parasitic is evaluated as follows:

$$\dot{W}_{par,prod} = \dot{W}_{gross,des} \cdot F_{par,prod,ref} \cdot F_{par,load} \cdot F_{par,temp}$$

where $F_{par,prod,ref}$ is the production based parasitic factor, Fpar,load is the load-based parasitic adjustment factor (defined below), and $F_{par,temp}$ is the temperature-based parasitic adjustment factor (also defined below).

Part load adjustment

Coefficients for a polynomial that adjusts the parasitic consumption as a function of power cycle gross power output. The result of the polynomial is denoted as $F_{par,load}$ in the Production based parasitic description above.

Temperature adjustment

Coefficients for a polynomial that adjusts the parasitic consumption as a function of the difference between ambient temperature and the reference power cycle ambient temperature. The result of the polynomial is denoted as $F_{par,temp}$ in the Production based parasitic description above.

7.7.4 Thermal Storage

Thermal Energy Storage (TES)

Full Load Hours of TES

The thermal storage capacity expressed in number of hours of thermal energy delivered at the power block's design thermal input level. The physical capacity is the number of hours of storage multiplied by the power block design thermal input. Used to calculate the TES maximum storage capacity.

Max thermal capacity (MWh)

The maximum thermal energy storage capacity of the TES, assuming that thermal storage can be fully discharged (see Thermal Storage Dispatch Control).

Charging energy derate

SAM applies the derate factor to the turbine efficiency for trough systems with storage to account for the lower steam temperature that results from imperfect heat exchange in the storage system.

Discharging energy derate

Efficiency adjustment factor. Used to calculate maximum TES discharge rate.

Charge based loss adj

Coefficients for evaluating a polynomial equation that adjust thermal losses from the thermal storage system based on charge level. The polynomial is formulated as follows:

$$F_{hl,tes,charge} = C_0 + C_1 \cdot X_{charge} + C_2 \cdot X_{charge}^2 + C_3 \cdot X_{charge}^3$$

where X_{charge} is the fractional charge level of the thermal storage system. The fractional charge is evaluated at the average charge level over the time step.

Temp based loss adj

Coefficients for evaluating a polynomial equation that adjust thermal losses from the thermal storage system based on ambient temperature. The polynomial is formulated as follows:

$$F_{hl,tes,temp} = C_0 + C_1 \cdot \left(T_{sf,des} - T_{db}\right) + C_2 \cdot \left(T_{sf,des} - T_{db}\right)^2 + C_3 \cdot \left(T_{sf,des} - T_{db}\right)^3$$

where $T_{sf,des}$ is the design-point solar field ambient temperature defined on the Solar Field page.

Thermal Storage Dispatch Control

The storage dispatch control variables each have six values, one for each of six possible dispatch periods. They determine how SAM calculates the energy flows between the solar field, thermal energy storage system, and power block. The fossil-fill fraction is used to calculate the energy from a backup boiler.

Storage Dispatch Fraction with Solar

The fraction of the TES maximum storage capacity indicating the minimum level of charge that the storage system can discharge to while the solar field is producing power. A value of zero will always dispatch the TES in any hour assigned to the given dispatch period; a value of one will never dispatch the TES. Used to calculate the storage dispatch levels.

Storage Dispatch Fraction without Solar

The fraction of the TES maximum storage capacity indicating the minimum level of charge that the storage system can discharge to while no solar resource is available. A value of zero will always dispatch the TES in any hour assigned to the given dispatch period; a value of one will never dispatch the TES. Used to calculate the storage dispatch levels.

Turbine Output Fraction

The fraction of design-point thermal load to the power block before part-load and temperature efficiency corrections. These values allow the user to dispatch the power cycle at a desired level according to the time-of-dispatch period.

Fossil Fill Fraction

A fraction of the power block design turbine gross output from the Power Block page that can be met by the backup boiler. Used by the power block module to calculate the energy from the backup boiler.

TOD Factor

The time-of-delivery (TOD) factors allow you to specify a set of TOD power price factors to model time-dependent pricing for projects with one of the Utility Financing options.

The TOD factors are a set of multipliers that SAM uses to adjust the PPA price based on time of day and month of year for utility projects. The TOD factors work in conjunction with the assumptions on the Financing page.

Note. For utility projects with no TOD factors, set the value for all periods to one.

For the CSP models, although the TOD power price factors are financial model inputs, they are on the Storage page because it includes other time-dependent variables, and there may be a relationship between the dispatch factors and the TOD power price factors. For PV and other technology models, the TOD power price factors are on a separate Time of Delivery Factors input page. For a description of how to specify the TOD power price factors for all technology models, see Time of Delivery Factors.

For a description of TOD-related simulation results, see PPA Revenue with TOD Factors.

Storage and Fossil Dispatch Controls

The thermal storage dispatch controls determine the timing of releases of energy from the thermal energy storage and fossil backup systems to the power block. When the system includes thermal energy storage or fossil backup, SAM can use a different dispatch strategy for up to six different dispatch periods.

Storage Dispatch

SAM decides whether or not to operate the power block in each hour of the simulation based on how much energy is stored in the TES, how much energy is provided by the solar field, and the values of the thermal storage dispatch controls parameters. You can define when the power block operates for each of the six dispatch periods. For each hour in the simulation, if the power block is not already operating, SAM looks at the amount of energy that is in thermal energy storage at the beginning of the hour and decides whether it should operate the power block. For each period, there are two targets for starting the power block: one for periods of sunshine (w/solar), and one for period of no sunshine (w/o solar).

The turbine output fraction for each dispatch period determines at what load level the power block runs using energy from storage during that period. The load level is a function of the turbine output fraction, design turbine thermal input, and the five turbine part load electric to thermal factors on the Power Block page.

For each dispatch period during periods of sunshine, thermal storage is dispatched to meet the power block load level for that period only when the thermal power from the solar field is insufficient and available storage is equal to or greater than the product of the storage dispatch fraction (with solar) and maximum energy in storage. Similarly, during periods of no sunshine when no thermal power is produced by the solar field, the power block will not run except when the energy available in storage is equal to or greater than the product of storage dispatch fraction (without solar) and maximum energy in storage.

By setting the thermal storage dispatch controls parameters, you can simulate the effect of a clear day when the operator may need to start the plant earlier in the day to make sure that the storage is not filled to capacity and solar energy is dumped, or of a cloudy day when the operator may want to store energy for later use in a higher value period.

Fossil Dispatch

When the fossil fill fraction is greater than zero for any dispatch period, the system is considered to include fossil backup. The fossil fill fraction defines the solar output level at which the backup system runs during each hour of a specific dispatch period. For example, a fossil fill fraction of 1.0 would require that the fossil backup operate to fill in every hour during a specified period to 100% of design output. In that case, during periods when solar is providing 100% output, no fossil energy would be used. When solar is providing less than 100% output, the fossil backup operates to fill in the remaining energy so that the system achieves 100% output. For a fossil fill fraction of 0.5, the system would use energy from the fossil backup only when solar output drops below 50%.

The boiler LHV efficiency value on the Power Block page determines the quantity of fuel used by the fossil backup system. A value of 0.9 is reasonable for a natural gas-fired backup boiler. SAM includes the cost of fuel for the backup system in the levelized cost of energy and other metrics reported in the results, and reports the energy equivalent of the hourly fuel consumption in the time series simulation results. The cost of fuel for the backup system is defined on the Trough System Costs page.

TOD Factor

The TOD factors allow you to specify a set of TOD factors for projects with one of the Utility Financing options. See above for details.

Defining Dispatch Schedules

The storage dispatch schedules determine when each of the six periods apply during weekdays and weekends throughout the year. You can either choose an existing schedule from one of the schedules in the CSP trough TES dispatch library or define a custom schedule. For information about libraries, see Working with Libraries.

The TES dispatch library only assigns period numbers to the weekday and weekend schedule matrices. The dispatch fractions assigned to each of the six periods are not stored in the library.

To choose a schedule from the library:

1. Click **Dispatch schedule library**.
2. Choose a schedule from the list of four schedules. The schedules are based on time-of-use pricing schedules from four California utilities.
3. Click **OK**.

   You can modify a schedule using the steps described below. Modifying a schedule does not affect the schedule stored in the library.
4. For each of the up to six periods used in the schedule, enter values for the dispatch fractions described above. Use the period number and color to identify the times in the schedule that each

period applies.

To specify a weekday or weekend schedule:

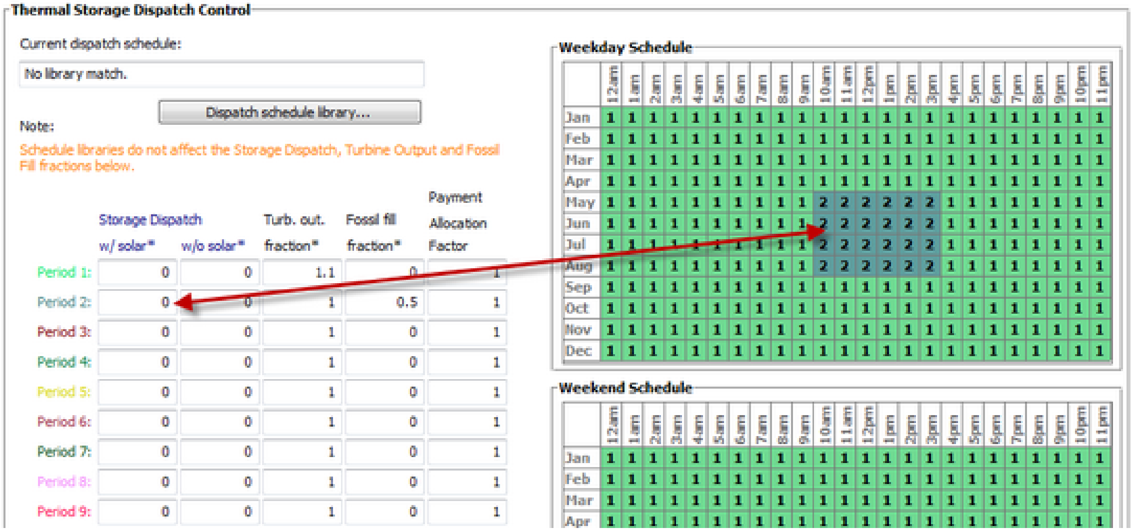
1. Assign values as appropriate to the Storage Dispatch, Turbine Output Fraction, Fossil Fill Fraction, and TOD Factor for each of the up to nine periods.
2. Click **Dispatch schedule library**.
3. Choose a **Uniform Dispatch**.
4. Click **OK**.
5. Use your mouse to draw a rectangle in the matrix for the first block of time that applies to period 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

6. Type the number 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

7. SAM shades displays the period number in the squares that make up the rectangle, and shades the rectangle to match the color of the period.



8. Repeat Steps 2-4 for each of the remaining periods that apply to the schedule.

8 Generic System

The generic system model allows you to represent a power plant using a simple model based on capacity factor and nameplate capacity, or to import hourly or sub-hourly electric generation data from another simulation model or measured from an operating system.

For a description of the model, see Overview.

The generic system input pages are:

- Generic System Costs
- Power Plant

8.1 Generic System Overview

The generic system model allows you to represent a power plant using a simple model based on capacity factor and nameplate capacity, or to import hourly or sub-hourly electric generation data from another simulation model or measured from an operating system.

You can use the generic system model for the following applications:

- Model a thermal power plant as a baseline case for comparison with renewable alternatives.
- Use energy generation profiles for any type of power system from other software with SAM's financial models.

- Use measured data from an installed plant with SAM's financial models.

The generic system model input pages are:

- Generic System Costs
- Power Plant

8.2 Power Plant

The Power Plant page allows you to specify the electricity output of the generic power system either as a nameplate capacity and capacity factor, or using time series data from other simulation software or measurements from an installed system.

After running simulations, you can see the hourly energy values in the Tables or time series graphs on the Results page.

Nameplate Capacity

The system's nameplate electrical capacity in electric kilowatts.

SAM uses the nameplate capacity to calculate capacity-based costs that you specify in $/kW on the Generic System Costs page, and also to calculate the capacity factor when you run the generic system model in user-specified generation profile mode.

Constant generation profile (via capacity factor)

In constant generation profile mode, SAM calculates the total energy generated by the system over a single year from the nameplate capacity, capacity factor, and performance adjustment factor values that you specify. SAM assumes that the system's hourly output is constant over the entire year so that:

Hourly Energy (kWh/hour) = Annual Energy (kWh/year) ÷ 8760 (hour/year)

Note. Because of the way SAM's internal calculations work, the hourly energy values displayed on the Results page data tables and graphs are not adjusted by the **percent of annual output** factor on the Performance Adjustment page.

Capacity factor

The power plant's capacity factor. SAM uses the value to calculate the first year annual generation value. The capacity factor input is disabled in user-specified generation profile mode.

User specified generation profile (hourly or subhourly)

SAM represents the system's electricity output using hourly or subhourly electricity generation data that you provide.

Hourly (or sub-hourly) Energy Production Profile

Click **Edit data** to import electric generation data from a text file, or to paste the data from your computer's clipboard.

In user-specified generation profile mode, SAM uses the time series data you provide to represent the system's electricity production.

If you are working with data in a time step other than hourly (60-minute time steps), click **Change time**

step and type the time step in minutes.

The data must be in a single column with one row for each time step. Each row should contain a value in kWh of electricity generated over the time step. For example, an hourly data set should consist of 8,760 rows of kWh/h values. A 15-minute data set would consist of 35,040 rows of values of kWh generated over each 15-minute time step.

To paste the data from a text editor, spreadsheet, or other software, copy the data to your clipboard, and then click **Paste**.

To import the data from a text file, click **Import**, navigate to the file, and open it.

If you import the data from a text file, the first row is reserved for a header, so do not include any electricity generation data in the first row. SAM checks the number of data rows in the file to ensure it is consistent with the time step you specify. For example, for a 60-minute time step, the text file should contain 8761 rows: One row at the top of the file for the header followed by 8760 data rows.

Derate and Heat Rate

Derate

A loss factor to account for output reductions caused by inefficiencies in the system, such as from wiring losses or other factors. For example, a value of 5% would reduce the system output in each time step by 5%.

Note. To calculate annual energy values for the financial models, SAM also applies the factors from the Performance Adjustment page.

Heat Rate

SAM uses the heat rate value to calculate the cost of fuel consumed by the system using a simple conversion of the kWh values you specify for the energy output to equivalent MMBtu of fuel.

If you are using the generic plant to represent a system that does not consume fuel, you should change the heat rate value to zero.

SAM uses the heat rate to calculate the annual year fuel cost:

Fuel Cost ($/yr) = Fossil Fuel Cost ($) × Heat Rate (MMBtu/MWhe) × Energy (kWh/yr) ÷ 1000 (kWh/MWh)

Where Fossil Fuel Cost is an annual cost in $/MMBtu that you specify on the Generic System Costs page, under Operation and Maintenance Costs, and Fuel Cost and Energy are reported on the Results page.

Calculated Values

SAM calculates the system's conversion efficiency and annual electrical output for the first year in the project cash flow based on the inputs you specify.

Thermal to Electric Conversion Eff.

SAM calculates and displays the system's thermal to electric conversion efficiency for reference to help you verify that the heat rate you specified is reasonable. SAM does not use this value during simulations.

Thermal to Electric Conversion Eff = 100% ÷ Heat Rate (MMBtu/MWhe) ÷ 0.2931 (Wh/Btu)

First Year Annual Generation

The system's output in the first year of operation.

This value is either the sum of hourly or subhourly generation values you specify with the user-specified generation profile option, or calculated as described below for the constant generation profile option.

First Year Annual Generation (kWh) = Nameplate Capacity (kW) × Capacity Factor (%) ÷ 100 % × Percent of Annual Output (%) ÷ 100 %

Where *Percent of Annual Output* is from the Performance Adjustment page.

9 Solar Water Heating

The Solar Hot Water model represents a two-tank glycol system with an auxiliary electric heater and storage tank for residential and commercial applications. The model allows you to vary the location, hot water load profiles, and characteristics of the collector, heat exchanger, and solar tanks.

The solar water heating input pages are:

- Location and Resource
- SWH System Costs
- SWH System

9.1 Solar Water Heating Overview

The solar water heating (SWH) model represents a one-tank water or glycol system with an auxiliary electric heater. The solar water heating performance model works with either the residential or commercial financial model, and assumes that the solar water heating system displaces purchases of electricity for an electric water heater. Installation and operating costs, financial assumptions, and retail electricity prices determine the value of the energy delivered by the solar water heating system.

Notes.

The solar water heating model in SAM 2013.1.15 and earlier has been replaced with a new model that has similar but not identical input variables. If you use the current version of SAM to open file or case created with the previous model, SAM converts the input variables from the previous model to the new model as closely as possible. You should expect slightly different results between the old and new models. See below for details.

As of September 2013, we are writing reference manual describing the SAM solar water heating model. When the manual is published, it will be available for download on the SAM website.

The SWH model allows you to vary the location, hot water load profiles, mains and set temperature profiles, and characteristics of the collector, heat exchanger, and solar tanks. The model was developed at the National Renewable Energy Laboratory for SAM.

To model a solar water heating system in SAM:

1. On the Location and Resource page, choose a weather file that represents the solar resource and ambient weather conditions at the project location.
2. On the SWH System page, specify the properties of the solar hot water system, including the hot water draw, collector parameters, storage tank and auxiliary heater parameters, and pump and heat exchanger parameters.
3. On the Performance Adjustment page, specify any adjustments you would like to make to the calculated hourly outputs to account for system down times or degradation.
4. On the SWH System Costs page, specify the cost of installing and operating the solar water heating system.
5. On the Incentives page, enter values for any incentives for which the project qualifies. For a commercial project, also review the inputs on the Depreciation page.
6. On the Utility Rate page, specify the electricity rate structure that applies to the system.
7. Run simulations and review results.

Solar Water Heating Model Notes

- SAM calculates the water mains inlet temperature based on the correlation to local air temperature used in the Building America Benchmark. The algorithm is described in Burch and Christensen (2007) *Towards Development of an Algorithm for Mains Water Temperature*. SAM reports the hourly water mains temperatures on Tables on the Results page as **T mains (C)**. If you have your own mains temperature data, you can override the mains inlet temperature calculation import an 8,760 hourly mains profile on the SWH System page.
- SAM assumes that the flow rate is constant over each hour, using values from the hourly hot water draw profile that you specify. SAM calculates the flow rate in kg/hr as the draw volume converted to kg for a given hour divided by one hour.
- Collectors are assumed to be flat plate collectors plumbed in parallel, with uniform flow through each collector at the tested flow rate.
- Collectors are characterized by the linear form of the collector efficiency and IAM (incident angle modifier) equations with parameters available from test data such as those available at www.solar-rating.org.
- The collector loop is assumed to be charged with water having $Cp = 4.18\ kJ/kG\text{-}^{o}C$ or glycol having $Cp = 3.4\ kJ/kG\text{-}^{o}C$. You can specify which fluid to use.
- Collector parameters are corrected for the flow rate, heat exchanger, and pipe losses using relations in Duffie and Beckman, *Solar Engineering of Thermal Processes*, 3rd. Edition. Specifically, see p. 307 for the flow rate corrections, p. 430 for pipe-loss adjustment, and p. 427 for heat exchanger adjustment.
- The heat exchanger is external to the solar tank, has no thermal losses, and is assumed to have the constant effectiveness that you specify on the SWH System page.
- A standard differential controller controls the collector loop pump. Pump power is input and assumed totally lost.
- The energy balance differential equations are approximated with the implicit-Euler method.

Solar Water Heating Model Results

After running simulations, SAM displays graphs and tables of results on the Results page. You can display hourly performance model results to explore details of how SAM models the system's performance.

- SAM does not explicitly model the auxiliary tank. Instead, it calculates the amount of energy required from the auxiliary heater to raise the water temperature from the solar storage tank to the set temperature and reports it as **Q auxiliary (kWh)** in the simulation results: $Q_{aux} = \dot{m}_{draw} C_p (T_{set} - T_{deliv})$, where T_{deliv} is the temperature of the water delivered from the solar tank. Because solar heat has been added to the water, $T_{deliv} > T_{mains}$, and less energy is needed to bring the water to the desired set temperature than would be required without the solar water heating system.
- SAM also calculates the energy that would be required without the solar water heating system and reports it as **Q auxiliary only (kWh):** $Q_{aux,only} = \dot{m}_{draw} C_p (T_{set} - T_{mains})$.
- The energy saved by the solar water heating system is **Q saved (kWh):** $Q_{saved} = Q_{aux,only} - Q_{aux} - P_{pump}$. This value is equivalent to the energy delivered by the solar water heating system.
- The solar fraction reported in the Metrics table is the ratio of the quantity of energy from the solar water heating system to the total energy required to heat the water: $f = \frac{Q_{saved}}{Q_{aux,only}}$.
- The hourly results **Q useful (kWh)** is the energy delivered by the collector to the solar water storage tank.
- The hourly outputs **Hourly Energy Delivered (kWh)**, **Q delivered (kWh)**, and **Q saved (kWh)** represent the same quantity. The Energy Delivered value will be less than the other two values when you specify system loss factors on the Performance Adjustment page (a **Percent of annual output** less than 100% or **Hourly Factors** values less than one).

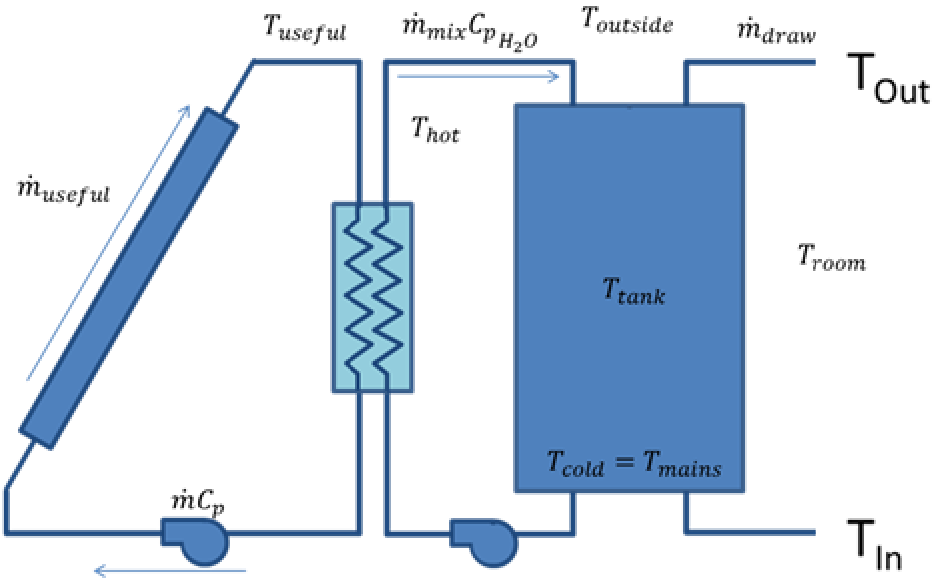
Important Notes about the New Solar Water Heating Model

The solar-water heating model has undergone a complete replacement since version 2013.1.15. The previous model was based on a two-tank glycol TRNSYS model. The TRNSYS model has been replaced with a faster, more customizable model based on a pending publication. Specific features that were hard-coded or unavailable in the previous model were:

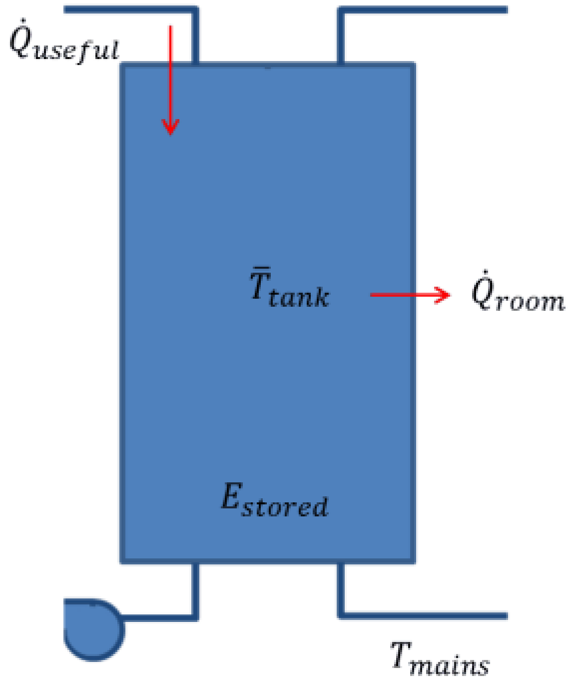
- Certain properties within the previous model were hard-coded or difficult to determine. For instance, the Diffuse Sky Model was based on the model by Hayes and Davies, but not specified as such except in the source code. Users can now choose between an isotropic sky model, or anisotropic models based on HDKR (Hay-Davies-Klucher-Reindl) or Perez.
- The irradiance inputs were also not clearly stated, and were based on Total and Beam irradiance. Now users can specify whether to use Beam and Diffuse irradiance, or Total and Beam irradiance to compute the incident irradiance quantity.
- The previous model used a hard-coded value of 0.2 for the ground reflectance (albedo). Now users can input a value.
- The collector mass flow rate was hard-coded as 55 kg/(hr m2), now the user can specify the value for both the anticipated use and the test condition mass flow rate.
- The previous model assumed a room-temperature of 20℃, now the user can input this value.
- The previous model did not appear to have any pipe properties or pumping efficiency factor. These features have been added.
- The previous model had an auxiliary tank required as part of the inputs. This has been removed. The calculation instead proceeds by performing energy balances on the solar storage tank and estimating the auxiliary energy that would be required in addition to the solar collector to bring the water delivered up to the desired user set-point.

Solar Water Heating Model Description

SAM models a closed-loop flat plate collector which transfers solar energy from the working fluid to the water in an external heat exchanger. This setup is often used in climates where freezing temperatures occur, because the collector working fluid can be different than water. Water from the solar tank is typically used to preheat water in an auxiliary water tank and reduce the amount of heat needed to bring the delivered water to the set point desired by the user. In the model used here, the solar tank is filled with water from the mains, pumped through the heat exchanger, and returned to the top of the tank.



The specific equations solved depend on whether useful solar energy is being collected or not. Below is a system diagram for when energy is being collected.

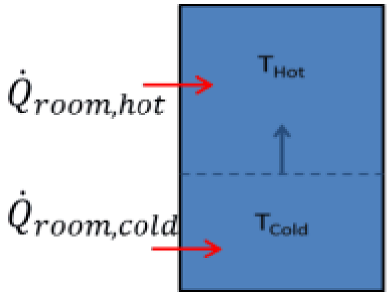


During solar collection, the tank is assumed to be fully mixed. This assumption is made because hot water continually is entering the top of the tank and mixing with cooler water underneath. A simple energy balance is performed on the tank to solve for the mean tank temperature each hour. Note that energy is added from the solar collector loop, energy is lost to the environment, mass enters the tank at the mains temperature and exits the tank at the mean tank temperature. Making an assumption that the mass in the tank is constant results in the differential equation:

$$\frac{dT_{tank}}{dt} = \frac{\dot{Q}_{useful} - \dot{Q}_{room} + \dot{m}C_p(T_{tank} - T_{mains})}{\rho V_{tank} C_p}$$

Where the value for the useful energy delivered is derived using relations from the third edition of *Solar Engineering of Thermal Processes* by John Duffie and William Beckman.

When useful solar energy is not being collected, the tank is assumed to be stratified into one hot node and one cold node.



This stratification occurs because user draws reduce the volume of hot water in the tank, and cold water from the mains is input to replace that water. Gradually, the cold volume will increase until solar collection begins again. In the stratified discharging mode, variable volume energy balances are performed on both the hot and cold nodes. The only heat transfer modeled is transfer to the environment which is drawn in a positive sense above. The heat transfer direction is usually reversed for the hot node. The mass coming into the cold node is at the mains temperature, and no mass is assumed to leave. The variable volume nature of each node means that mass cannot be assumed constant, resulting in the following differential equation for the cold node:

$$\frac{dT_{cold}}{dt} = \frac{\dot{Q}_{room,cold} + \dot{m}C_p(T_{mains} - T_{cold})}{\rho V_{cold} C_p}$$

The mass leaving the hot node at the hot-node temperature, and no mass is assumed to enter.

$$\frac{dT_{hot}}{dt} = \frac{\dot{Q}_{room,hot}}{\rho V_{hot} C_p}$$

These three differential equations are approximated for each hour, with the express interest of determining how much energy is saved by using solar water heating.

9.2 Solar Water Heating

The SWH System page is where you specify the design parameters for the solar water heating system. For a general description of the model, see Solar Water Heating Overview.

Notes.

The solar water heating model in SAM 2013.1.15 and earlier has been replaced with a new model that has similar but not identical input variables. If you use the current version of SAM to open file or case created with the previous model, SAM converts the input variables from the previous model to the new model as closely as possible. You should expect slightly different results between the old and new models. See here for details.

You can explore the details of the SWH model by reviewing the hourly performance model results.

Hot Water Draw

You must specify a set of 8,760 hourly values representing the hot water system's heating load. You can either import values from a text file, paste values from a spreadsheet or other file using your computer's clipboard, or type a set of 24-hour load profiles for each of the twelve months of the year, with the option of specifying separate profiles for weekdays and weekends.

See Specifying the Hot Water Draw for details.

Hourly Hot Water Draw Profile (kg/hr)

The mass of hot water drawn over an hour. Click Edit Data to specify the hot water draw.

Scale draw profile to average daily usage

Check this box to scale the 8,760 hourly data to the average value you specify in Average Daily Hot Water Usage.

Average Daily Hot Water Usage (kg/day)

The daily average hot water usage. SAM scales the 8,760 hourly data you specify in the Edit Data window to this annual average value.

Total Annual Hot Water Draw (kg/year)

SAM calculates the total annual hot water draw in kilograms per year by adding the 8,760 values you specify in the Edit data window, and scaling it to the average daily hot water usage value you specify.

System

Tilt (degrees)

The array's tilt angle in degrees from horizontal, where zero degrees is horizontal, and 90 degrees is vertical. As a rule of thumb, system designers often use the location's latitude (shown on the Location and Resource page) as the optimal array tilt angle. The actual tilt angle will vary based on project requirements.

Azimuth (degrees)

The array's east-west orientation in degrees. An azimuth value of 180° is facing south in the northern hemisphere. As a rule of thumb, system designers often use an array azimuth of 180°, or facing the equator.

Total system flow rate (kg/s)

The flow rate in the collector loop when it is operating.

Working fluid

The fluid in the solar collector loop, which one may choose either glycol or water.

Number of Collectors

The number of collectors in the system

Diffuse Sky Model

Allows three different sky models to be chosen: Isotropic, HDKR (Hay-Davies-Klucher-Reindl), or Perez.

Irradiance Inputs

Allows either Beam & Diffuse irradiation or Total & Beam irradiation.

Albedo

The ground reflectance.

Total Collector Area (m2)

Total area of all collectors. :

Total Collector Area = *Single Collector Area* × *Number of Collectors*

Rated System Size (kWt)

The system's nominal capacity in thermal kilowatts, used to in capacity based cost and financing calculations, and to calculate the system capacity factor reported in results:

Nameplate Capacity = *Total Collector Area* × *FRta - FRUL* × *30/1000*

Collector

Enter user defined parameters

Choose this option to specify your own collector parameters.

Select from library

Use this option to choose a collector from the collector library. SAM applies parameters from the library to model the collector.

The collector library contains parameters for collectors certified by the Solar Rating and Certification Corporation (SRCC): http://www.solar-rating.org.

Search by collector name

Type a few characters of the collector manufacturer or model name to filter the list of available collectors.

Click the collector name in the list to select it.

SRCC#

The collector's SRCC number.

Type

The collector's optic type.

Fluid

The solar system's heat transfer fluid.

Test flow

Fluid flow rate used to generate test data.

The **User-defined Collector** variables are active for the **User Specified** option. (SAM ignores the user-specified values when you use the **Choose From Library option**.)

Collector Area

Area of a single collector. Choose a value consistent with the area convention used in the collector efficiency equation. For example, use gross area for all SRCC data.

FRta

Optical gain a in Hottel-Whillier-Bliss (HWB) equation, $hcoll = a - b \times dT$.

FRUL (W/m2-°C)

Thermal loss coefficient b in the Hottel-Whillier-Bliss (HWB) equation, $hcoll = a - b \times dT$.

IAM

The incident angle modifier coefficient: The constant *b0* in the equation, $IAM = 1 - b0 \times (1/\cos(q) - 1)$.

Solar Tank and Heat Exchanger

Solar Tank Storage Volume (m³)

The actual volume of the solar storage tank. Note that the actual volume may be different from the rated volume.

Solar Tank Height/Diameter Ratio

Defines the solar storage tank geometry, and by extension its geometry.

Solar Tank U Value (W/m²-ºC)

The solar storage tank loss coefficient. Note that 1 kJ/h-m²-ºC = 3.6 W/m²-ºC.

Heat Exchanger Efficiency

Heat exchanger effectiveness, where the effectiveness e, is defined as *e = (Tcold-out – Tcold-in) / (Thot-in - Tcold-in)*.

Outlet Set Temperature

The desired set temperature delivered to the user. The value in this box is used only if **Use custom set temperatures** is not checked.

Ambient Temperature in Mechanical Room

The temperature where the solar tank is stored. This temperature is used to compute heat transfer to and from the storage tank as:

$$Q_{loss} = UA_{tank}(T_{room} - T_{tank})$$

Piping and Pumping

Total piping in system (m)

Estimate of piping in system to compute pipe losses. For studies where piping loss is not of interest, reduce this length to small value, such as 0.001 m.

Pipe diameter (m)

Average diameter of system piping

Pipe Insulation Conductivity (W/m2 - °C)

Thermal conductivity of pipe insulation

Pipe insulation thickness (m)

Average thickness of insulation

Pump Power (W)

The pump's peak power rating in Watts.

Pump Efficiency (0 to 1)

An estimate of the pump efficiency.

Custom Water Input

Use custom mains profile

If checked, the model will use the hourly data that you specify instead of calculating the mains temperature from the ambient temperature. Check this box if you have detailed experimental measurements of the mains temperature.

Hourly custom mains profile (°C)

A set of 8760 values specifying the incoming mains temperature, used only if **Use custom mains profile** is checked.

Use custom set temperatures

Check this box if you want to specify custom hourly or monthly values for the outlet set temperature.

If the box is not checked, SAM uses the **Outlet set temperature** value for every hour of the year.

Hourly custom set temperatures

A set of 8760 values specifying hourly desired set temperatures. SAM only uses these values if **Use**

custom set temperatures is checked.

Specifying the Hot Water Draw

The hot water draw represents the solar water heating system's hourly thermal load over the period of one year.

A load data file is a text file with 8,761 rows: The first row is a text header that SAM ignores, and the remaining 8,760 rows must contain average hourly hot water demand data in kg/hr. The first data element represents the hour beginning at midnight and ending at 1 a.m. on January 1 when you run the model with a weather file in one of SAM's standard formats, TMY2, TMY3, or EPW.

To import load data from a properly formatted text file:

1. On the SWH System page, click **Edit data**.
2. In the Edit Hourly Data window, click **Import**.
3. Navigate to the folder containing the load data file and open the file.

   SAM displays the data in the data table. Use the scroll bars to see all of the data.
4. Click **OK** to return to the SWH System page.

To import load data from a spreadsheet or other file:

1. On the SWH System page, click **Edit**.
2. Open the spreadsheet containing the load data. The data must be in a single column of 8,760 rows, and expressed in kg.
3. In the spreadsheet, select the load data and copy it.
4. In the Edit Hourly Data window, click **Paste**.
5. You can also copy data from the Edit Hourly Data window by clicking **Copy**, or export the data to a text file by clicking **Save**.

If you do not have a complete 8,760 set of load data, you can use a set of daily load profiles for each month, and use SAM to create a set of 8,760 values.

To create a load data set using daily load profiles:

1. On the SWH System page, click **Edit data**.
2. In the Edit Hourly Data window, check **Use monthly grid to generate 8760 data**.
3. For each month of the year, define a daily load profile by typing a kg hot water draw value for each of the 24 hours of the day. The first column represents the first hour of the day, beginning at midnight and ending at 1:00 a.m.

   If you want to specify separate load profiles for weekdays and weekends, click Weekend Values to define profiles that apply to two days each week. SAM arbitrarily assumes that the first day in the data set is a Monday, and that weekends fall on Saturday and Sunday.

   If you do not specify separate weekend profiles, SAM applies the weekday profile to all days of the week.
4. When you have specified all of the daily load profiles, click **To 8760** to transfer the data to the User Specified data table. You must complete this step for SAM to use the profile data in simulations.

   When you define a load with daily load profiles, SAM assumes that all days in a given month have identical load profiles.

5. If you want to export the 8,760 data to a text file, click **Save**. You can also copy the data to a spreadsheet or other file by clicking **Copy**, and then pasting the data in to the file.

10 Wind Power

The Wind Power model is for projects involving one or more large or small turbines with any of the financing options.

The wind power model uses weather data from a database for United States locations.

The wind power model input pages are:

- Wind Resource
- Turbine
- Wind Farm
- Wind Farm Costs

10.1 Wind Power Overview

The Wind Power model is for projects involving one or more large or small turbines with any of the financial models for residential, commercial, or utility projects.

The Wind Power input pages are:

- Wind Resource
- Turbine
- Wind Farm
- Wind Farm Costs

Wind Power Model Algorithm

Note. As of October 2013, NREL is writing a reference manual describing SAM's wind power model algorithm. When the manual is finished, it will be available on the SAM website at https://sam.nrel.gov/reference.

SAM's wind power model uses wind resource data that you specify on the Wind Resource page to calculate the electricity delivered to the grid by a wind farm that consists of one or more wind turbines.

SAM can either read wind resource data from a time series data file in the SRW format, or make calculations based on an estimate of the wind resource specified using a Weibull distribution.

SAM calculates the wind farm's output over a single year in hourly time steps. It uses the following algorithm to calculate the wind farm output for each time step of the simulation:

1. Determine the wind data height, and adjusts the wind resource data to account for differences between the turbine hub height and the wind resource data height. See Hub Height and Wind Shear below for details.
2. Calculate output of a single turbine, accounting for the turbine's height above the ground.

   On the Turbine page, you choose to represent the turbine's performance characteristics either as a turbine power curve from the turbine library, or by specifying values for a set of turbine design parameters. For both options, you also specify a turbine hub height and shear coefficient.
3. Calculate output of wind farm, accounting for wake effects.

   On the Wind Farm page, you specify the number of turbines and wind farm layout geometry for a simple representation of a wind farm on a flat surface, and a value for the ambient turbulence intensity. See Wake Effect Model below for details.
4. Adjust wind farm output.

   You can account for additional losses by specifying a value for a wind farm loss factor on the Wind Farm page.
5. Calculate electricity delivered to the grid.

   SAM adjusts the wind farm's output using the adjustment factors you specify on the Performance Adjustment page to represent curtailment, system availability, or other operating losses.

Hub Height and Wind Shear

SAM makes wind shear adjustments to account for variation in wind speed with height above the ground.

When you choose the **Wind Resource by Location** option (time series data from a wind data file) on the Wind Resource page, SAM ignores the value of the **Shear Coefficient** on the Turbine page when the data file contains wind speed data columns for more than one height and the turbine hub height is between the minimum and maximum wind data heights in the file. SAM looks for the data column with the measurement height closest to the hub height. If it finds an exact match, it uses that data column. If it does not find an exact match, SAM finds the two measured heights on either side of the hub height and uses linear interpolation to estimate the wind speed at the hub height.

For wind direction data, SAM interpolates to estimate wind direction at different hub heights when the wind direction for two neighboring measurement heights differ by less than 90 degrees. Otherwise it uses the direction measured closest to the hub height.

> **Note:** SAM stops simulations and reports a simulation error if either of the following is true:
>
> The hub height is more than 35 meters above the highest measurement height or more than 35 meters below the lowest measurement height.
>
> The measurement height used for the wind speed is more than 10 meters from the measurement height used for direction.

Wind Power Law

SAM uses the value of the **Shear Coefficient** on the Turbine page to estimate the wind speed at the hub height instead of the method described above under the following conditions:

- The wind speed data in the wind data file is measured at more than one height, and the turbine hub height is above the maximum height or below the minimum height in the file.
- The wind data file with contains wind speed data measured at a single height.

- You choose the **Wind Resource Characteristics** option on the Wind Resource page to specify a Weibull distribution instead of a wind data file.

The wind power law equation to estimate the wind speed at the turbine height v_{hub}, using the wind speed v_{data} and wind measurement height h_{data} from the data file, and the turbine hub height h_{hub} and shear coefficient α is:

$$v_{hub} = v_{data} \times \left(\frac{h_{hub}}{h_{data}}\right)^{\alpha}$$

For data from a wind file with more than one column of wind speed data, h_{data} is either the lowest or highest wind speed data height, whichever is closest to the hub height. For a wind data file with wind speed data measured at one height, h_{data} is the that height. For wind resource that you specify using a Weibull distribution, h_{data} = 50 meters.

Elevation above Sea Level

SAM assumes that the wind turbine power curve on the Turbine page represents the turbine's performance at sea level. How SAM adjusts the turbine power curve to represent its performance at the project elevation above sea level depends on the options you choose to model the wind resource and turbine.

When you choose the **Wind Resource by Location** option (time series data from a wind data file) on the Wind Resource page, SAM uses the ideal gas law with values from the file to calculate the air density ρ, and adjusts the turbine output by the ratio of air density to the air density at sea level: $\rho \div 1.225$ kg/m^3. The air density is a function of the air temperature T (converted to Kelvin), atmospheric pressure P, and the gas constant $R_{specific}$ = 287.058 J/kg?K:

$$\rho = \frac{P}{R_{specific} \cdot T}$$

When you choose the **Wind Resource Characteristics** option (Weibull distribution) with:

- The **Select a turbine from the list** option on the Turbine page, SAM does not adjust the power curve, effectively modeling the turbine as if it were installed at sea level.
- The **Define the turbine characteristics below** option, SAM uses the **Elevation above Mean Sea Level** value from the Wind Resource page to calculate the air density for the turbine power output calculations.

Wake Effect Model

As wind passes through a wind turbine rotor, its speed and turbulence characteristics change. For wind farms with more than one turbine, the spacing of turbines affects the wind farm output because upwind turbines can reduce the energy in the wind available for downwind turbines.

SAM allows you to choose from three different wake effect models to estimate the effect of upwind turbines on downwind turbine performance:

- **Simple Wake Model** is described below, and in more detail in Chapter 3 of Quinlan P (M.S., 1996), *Time Series Modeling of Hybrid Wind Photovoltaic Diesel Power Systems,* University of Wisconsin-Madison. (ZIP 2.1 MB).
- **Park (WAsP)** is described in *Open Wind Theoretical Basis and Validation* (Version 1.3, April 2010), 2.1 Park Model, p. 6.

- **Eddy-Viscosity** is described in *Open Wind Theoretical Basis and Validation* (Version 1.3, April 2010), 2.3 Eddy-Viscocity Wake Model, p. 7.

Simple Wake Model

The model makes the following simplifying assumptions:

- All turbines in the wind farm have the same hub height and height above sea level.
- The wind farm terrain is uniform with a single ambient turbulence coefficient

The wake model uses wind direction data from the wind data and information about the relative position of turbines from the inputs you specify on the Wind Farm page to calculate the distance between neighboring downwind turbines and neighboring crosswind turbines. It then calculates a set of coefficients representing the effects of the turbine on the wind speed:

- Power coefficient, C_p
- Thrust coefficient, C_t
- Turbulence coefficient, σ

The power and thrust coefficients are related by the axial induction factor, a:

$$C_p = 4 \cdot a \cdot (1 - a)^2$$

$$C_t = 4 \cdot a \cdot (1 - a)$$

The resulting relationship between C_p and C_t for $0 < C_p < 0.6$ is:

$$C_t = -A + B \cdot C_p + C \cdot {C_p}^2 + D \cdot {C_p}^3$$

Where A = -0.01453989, B = 1.473506, C = -2.330823, and D = 3.885123.

The power coefficient is a function of the turbine power $P_{turbine}$ that SAM calculates from the power curve and the theoretical power in the wind P_{wind}:

$$C_p = \frac{P_{wind}}{P_{turbine}}$$

The theoretical power in the wind P_{wind} depends on the air density σ_{air}, wind speed v_{wind}, and rotor radius, r_{rotor}:

$$P_{wind} = 0.5 \cdot \sigma_{air} \cdot {v_{wind}}^3 \cdot \pi \cdot {r_{rotor}}^2$$

The difference in wind speed ΔU between an upwind and downwind turbine is then:

$$\Delta U = \frac{C_t}{4 \cdot \sigma^2 \cdot x^2} \cdot e^{\left(\frac{-r^2}{2 \cdot \sigma^2 \cdot x^2}\right)}$$

Where σ is the local turbulence coefficient at the turbine, and x and r are, respectively, the downwind and crosswind distance between turbines expressed as a number of rotor radii.

The local turbulence coefficient calculation is beyond the scope of this description. For the first turbine, the value is equal to the turbulence coefficient on the Wind Farm page. For downwind turbines, see Quinlan (1996) p 55-57.

10.2 Siting Considerations

The Siting Considerations page allows you to download a list of public agencies and land ownership and environmental information for locations in the United States from NREL's Wind Prospector database. The list is informational only, and does not affect simulation results.

Download Siting Considerations from Wind Prospector

You can download siting considerations data for the latitude and longitude specified in the weather file, or for a location that you specify.

Use location from weather file

Choose this option to download data for the latitude and longitude in the wind resource data file.

> **Note.** Many of the default wind resource data files do not have latitude and longitude data. For those files, you should enter location data to download the siting considerations data.

Enter location

Choose this option to type a street address or latitude and longitude instead of using location data from the wind resource file.

Site Radius

Defines a circle around the location to include in the search.

Download Siting Considerations

Click the button to download the siting considerations data. If you chose Enter location, you will be prompted to type either a street address or latitude and longitude.

Go to Wind Prospector website

Click the link to open the Wind Prospector website (http://maps.nrel.gov/wind_prospector) in your web browser.

Results

After you click **Download Siting Considerations**, SAM displays a list of the considerations from the Wind Prospector website. The percentages show the portion of the circle of land defined by the location and radius you specified (the location's latitude and longitude are the center of the circle) occupied by each land category.

These results do not affect SAM's simulations, and are intended to give you an idea of the issues and organizations likely to be involved in the project's permitting process. SAM does not automatically adjust the costs on the System Costs page to account for these considerations.

Confirmation

The latitude, longitude, and radius sent to the Wind Prospector website for the data query.

10.3 Turbine

The wind turbine parameters specify the turbine power curve and hub height of a single turbine.

For a project with multiple turbines, SAM assumes that the wind farm consists of identical turbines.

SAM offers two options to specify the turbine parameters:

Select a Turbine from the list

Choose a turbine from SAM's wind turbine library. SAM automatically populates the power curve, **Rated Output** and **Rotor Diameter** values from the library. You cannot change these values.

Use this option when you want to model a project that uses commercially available wind turbines.

Note. You can use the Library Editor to add turbines to the Wind Turbine library. The turbine parameters are stored in SAM/Wind Turbine Library.

Define the turbine characteristics below

Use this option when you are investigating different turbine design parameters.

For either option, you specify the turbine hub height and shear coefficient:

Hub Height

The height of the center of the rotor above the ground.

Note. If you specify a wind resource file on the Wind Resource page, and the difference between the hub height and the nearest wind speed data height in the file is greater than 35 meters, SAM stops simulations and generates an error message.

Shear Coefficient

The shear coefficient is a measure of the variation in wind speed with height above the ground at the turbine installation site. The default value of 0.14 (1/7) is a common assumption for the value in wind resource studies on land, and 0.11 may be appropriate over water for offshore wind farms.

How and whether SAM uses the shear coefficient to estimate the wind speed at the turbine's hub height depends on the option you choose on the Wind Resource page:

- For the **Wind Resource by Location** option (wind data file with time series data), SAM ignores the shear coefficient unless the file contains wind speed data at only a single height, or when the turbine hub height is either below the lowest height or above the highest height in the file.
- For the **Wind Resource Characteristics** option (specify a Weibull distribution), SAM uses the shear coefficient with the power law, assuming that the measured wind speed height is 50 meters above the ground.

See Wind Shear and Power Curve Adjustments for an explanation of how SAM uses this value.

Wind Turbine Design Parameters

The wind turbine design parameters are the input variables that are active when you choose the **Define the turbine characteristics** option.

Note. When you use the **Select a turbine from the list** option, you can ignore the turbine design parameters. SAM only uses these values when with the **Define the turbine characteristics below** option.

User Defined Rated Output

The turbine's nameplate capacity in kW.

User Defined Rotor Diameter

The turbine's rotor diameter in meters.

Max Cp

The rotor's power efficiency.

The fraction of the rotor's total available power that the blades can convert to mechanical power. The theoretical maximum is the Betz limit of 0.59.

Max Tip Speed

The maximum velocity of the blade tip.

Max Tip Speed Ratio

The maximum ratio of the blade tip speed to wind speed.

Cut-in Wind Speed

The minimum wind speed at which the turbine generates electricity.

Cut-out Wind Speed

The maximum wind speed at which the turbine generates electricity.

Drive Train Design

Choose an option from the four available designs.

Blade Design

Choose an option from the two available designs.

Tower Design

Choose an option from the two available designs.

10.4 Wind Farm

The Wind Farm page allows you to specify the number of turbines in the project and includes a simple representation of the wind farm layout to estimate wake effect losses that result when upwind turbines interfere with wind flow to downwind turbines.

Use more than one wind turbine

Check this option if you want to model a project with two or more turbines. SAM assumes that all of the turbines in the wind farm are the same.

To model a project with one turbine, clear the check box. SAM disables the Turbine Layout options when the check box is cleared.

Note. The **Use more than one wind turbine** option is disabled when you choose the **Wind Resource Characteristics** option on the Wind Resource page because that method of specifying the wind resource does not include information about wind direction that SAM requires to model wake effects for systems with more than one turbine.

Number of Turbines

Number of turbines in the project specified under **Turbine Layout**.

System Nameplate Capacity

Total capacity of the project in AC kilowatts, equal to the product of the number of turbines in the wind farm and the nameplate capacity of a single turbine (**Rated Output** from the Turbine page).

Turbine Layout

The Turbine Layout options allow you to specify the parameters of a project with two or more turbines. You must check **Use more than one wind turbine** to make the parameters active.

You can either specify the turbine layout using the turbine and row spacing inputs, or by importing a text file of turbine locations.

Enter wind turbine locations using a file

Use this option to import a text file of turbine locations. When you import the file, SAM displays the turbine locations in the turbine layout map.

When you chose the **Enter wind turbine locations using a file**, click **Import turbine layout file** to open the file. SAM looks for a file with the *.csv* extension with the following format:

- A text file.
- The first row is a header that SAM ignores.
- Rows 2 to up to 502 each contain comma-separated values of x,y coordinates in meters indicating a single turbine's position as it would appear on the turbine layout map.

For an example of a turbine location file, see the *sample_turbine_layout.csv* file in the */samples* folder in the SAM installation folder (*c:\SAM\2013.9.20\samples*).

Enter wind turbine locations using controls below

Use this option to specify the turbine locations using turbine and row spacing inputs.

Turbine Layout Map

A diagram showing the locations of turbines in the field. Each blue dot in the map represents a turbine.

Shape

Choose the shape defined by a set of lines connecting outermost turbines in the project.

Turbines per Row / Turbines in First Row

For the **Square / Rectangle / Parallelogram** shape, **Turbines per Row** is the number of turbines in each row.

For the **Triangle / Trapezoid** shape, **Turbines in the First Row** determines the number of turbines at the base of a triangle or trapezoid. SAM assumes that the number of turbines in each successive row is one less than in the previous row.

Number of Rows

Number of rows of turbines in the wind farm.

Notes.

To specify a triangle shape, **Number of Rows** should be equal to **Turbines in First Row**. For a trapezoid, Number of Rows should be less than **Turbines in First Row**.

If you specify more rows than there are turbines in the first row, SAM assumes a triangle shape, and sets the number of rows equal to the number of turbines in the first row.

Turbines in Layout

The total number of turbines in the wind farm. For a square, rectangle, or parallelogram shape:

Turbines in Layout = Turbines per Row × Number of Rows

For a triangle or trapezoid shape, SAM assumes that each row has one less turbine than the previous row:

Turbines in Layout = Turbines in First Row + Turbines in Second Row + Turbines in Third Row

+ ... + Turbines in Last Row

Turbine Spacing

Distance in meters between turbines in each row.

Row Spacing

Distance in meters between rows.

Offset for Rows

The distance in meters between a line drawn through a turbine perpendicular to its row, and a similar line drawn through a turbine in the nearest neighboring row.

Offset Type

Every Other Row applies the offset distance to alternating rows. **Each Row** applies the distance to every row.

Row Orientation

The angle west of north of a line perpendicular to the rows of turbines. A value of either zero or 180 degrees means the rows are parallel to the equator.

You can set the value by either typing a number or dragging the slider with your mouse.

The compass rose indicates the cardinal directions.

Wind Farm Losses

Expected losses in the wind farms electrical output as a percentage of the wind farm's total output. Use this factor to account for wiring, transformer, or other losses.

Notes.

SAM calculates wake effect losses based on the turbine layout that you specify, so you should not include these losses in the **Wind Farm Losses** value. See Wake Effect model for details.

SAM also applies the performance adjustment factors from the Performance Adjustment page to the system's electrical output. You can use the performance adjustment factors to represent system availability, curtailment, and annual decline in output.

Turbulence Coefficient

The ambient turbulence intensity representing variation in wind speed caused by terrain or local thermal effects as air moves across the wind farm. SAM uses this value in the wake effect model. Wake effects are more significant for a wind farm with a lower turbulence coefficient than for one with a higher coefficient.

The turbulence intensity is the standard deviation of the wind speed at a short time step divided by the mean wind speed. For smooth terrain such as a flat plain with little vegetation and a low turbulence coefficient, a typical value might be 0.1 (or less over water for offshore wind farms). For a forest or area with air mixing caused by thermal effects with a high turbulence coefficient, a typical value might be 0.5.

Wake Model

SAM allows you to choose from three different wake effect models to estimate the effect of upwind turbines on downwind turbine performance. For details see wake effect model.

- **Simple Wake Model** uses a thrust coefficient to calculate the wind speed deficit at each turbine due to wake effects of the upwind turbines. This is the original wake effect model used in SAM versions 2013.1.15 and earlier.
- **Park (WAsP)** calculates the wind speed deficit behind each turbine using a decay constant, and calculates the overlap of that wake profile with the downwind turbine to calculate the wind speed at the downwind turbine. This model was originally developed for the Risø DTU WAsP wind farm model.
- **Eddy-Viscosity** is similar to the Park model, except that the wind speed deficit behind each turbine is assumed to have a Gaussian shape (there is no decay constant).

11 Geothermal

SAM's geothermal models include:

- Geothermal Power
- Geothermal Co-production

For an overview of all technologies, see Technology Options.

11.1 Geothermal Power

The geothermal power plant model calculates the output of a power plant that uses heat from below the surface of the ground to drive a steam electric power generation plant. SAM analyzes the plant's performance over its multi-year lifetime, assuming that changes in the resource and electrical output occur monthly over a period of years. (This is different from the solar and other technologies modeled by SAM, where SAM models the system's performance on an hour-by-hour basis over a single-year period.)

For a general description of the geothermal power model, see Geothermal Overview.

The Geothermal Power input pages are:

- Ambient Conditions
- Geothermal System Costs
- Resource
- Plant and Equipment
- Power Block

11.1.1 Geothermal Power Overview

SAM's geothermal power model is based on the U.S. Department of Energy's Geothermal Electricity Technology Evaluation Model (GETEM), http://www1.eere.energy.gov/geothermal/getem.html. The model calculates the annual and lifetime electrical output of a utility-scale geothermal power plant, and the levelized cost of energy and other economic metrics for the plant.

For more details about the model, please refer to the documentation for the U.S. Department of Energy's Geothermal Electricity Technology Evaluation Model (GETEM), which you can download from http://www1.eere.energy.gov/geothermal/getem_manuals.html

The geothermal power model calculates the output of a power plant that uses heat from below the surface of the ground to drive a steam electric power generation plant. SAM analyzes the plant's performance over its lifetime, assuming that changes in the resource and electrical output occur monthly over a period of years.

SAM can be used to answer the following kinds of questions:

- What is the levelized cost of a geothermal power plant, given a known configuration and resource?
- How does changing the design of the plant affect its output and levelized cost of energy?
- What plant size is required to meet an electric capacity requirement?
- Given a known number of wells, what would the plant's electric capacity be?

SAM models the following types of systems:

- Hydrothermal resources, where the underground heat reservoir is sufficiently permeable and contains sufficient groundwater to make the resource useful without any enhancements.
- Enhanced geothermal systems (EGS) that pump water or steam underground to collect heat stored in rock. These systems involve drilling or fracturing the rock to improve heat transfer. Over time (typically years), as heat is collected from the rock, its temperature decreases, and more drilling is required. SAM's recapitalization cost accounts for the cost of these improvements to reach new resources.
- Both flash and binary conversion plants.

The geothermal input pages are:

- Ambient Conditions
- Geothermal System Costs
- Resource
- Plant and Equipment
- Power Block

11.1.2 Geothermal Resource

Resource Characterization

The resource characterization inputs describe the energy available in the underground geology at the project site.

Resource Type

For **Hydrothermal** resources, the rocks have enough permeability, heat, and water to be useful immediately.

For **Enhanced Geothermal System (EGS)** resources, there is heat, but either water, or permeability, or both are missing and must be added during the project development and operation.

Total Resource Potential

The total resource potential is an estimate of the total size of the energy available in the underground thermal reservoir. SAM uses the value to calculate the number of times over the project life that new drilling would be required to renew the resource based on the reduction of the reservoir's temperature over time. As the system operates and draws heat from the reservoir, the reservoir temperature drops. After a number of years, there may be insufficient heat to maintain the steam temperature required to drive the plant, and new wells may need to be drilled to renew the resource by reaching another section of the reservoir where there is sufficient heat. Eventually, the reservoir may cool to the point that it is impossible to find more heat by drilling from the plant location. Total resource potential is meant to be a measure of how many times the reservoir can be renewed. For example, a 210 MW reservoir divided by 30 MW plant capacity could support up to seven renewals (210 ÷ 30 = 7).

Resource Temperature

The temperature of the reservoir at the depth given by the resource depth.

Resource Depth

The depth below ground at which the temperature specified by the resource temperature exists.

Note. In general, the higher the temperature of the resource, the lower the cost of energy generated by the plant. However, SAM does not handle systems that operate at extremely high steam temperatures that require special equipment.

For a description of the resource characterization inputs, see page 2 of the "Revisions to GETEM Spreadsheet (Version 2009-A15)" document available at http://www1.eere.energy.gov/geothermal/getem_manuals.html.

Reservoir Parameters

The reservoir parameters describe the geologic formation. SAM provides three options for calculating the change in reservoir pressure. The option you choose affects the plant's overall efficiency, which depends on the design parameters that SAM displays under **Calculated Design**. The design value determines the pumping power or parasitic load required by the plant.

For a description of the reservoir parameters, see page 6 of the "Revisions to GETEM Spreadsheet (Version 2009-A15)" document available at http://www1.eere.energy.gov/geothermal/getem_manuals.html.

11.1.3 Plant and Equipment

Note. This topic is still under development.

For more details about SAM's geothermal model, please refer to the documentation for the U.S. Department of Energy's Geothermal Electricity Technology Evaluation Model (GETEM), which you can download from http://www1.eere.energy.gov/geothermal/getem_manuals.html

If you have questions about SAM's geothermal model, please contact sam.support@nrel.gov.

Plant Configuration

The plant configuration describes the plant's conversion technology and how SAM models it.

Specify plant output

The Specify Plant Output option allows you to specify the plant's electrical capacity in kilowatts. SAM calculates the plant size required to ensure that the plant's net output meets this output requirement, with enough extra power to supply parasitic load defined by the Calculated Design values on the Resource page.

Use exact number of wells

When you choose Use Exact Number of Wells, you specify the number of wells, and SAM calculates the plant's gross capacity based on the energy available from the wells, and the plant net output by subtracting the parasitic load from the gross output. The parasitic load is defined by the Calculated Design values on the Resource page.

Conversion Plant Type

The Conversion Plant Type determines the plant's steam-to-electricity conversion efficiency, also called "brine effectiveness." The plant efficiency is different from the system efficiency, which also accounts for pumping losses from the parasitic load.

Binary

When you choose the Binary option, you can specify the plant efficiency.

Plant Efficiency

The steam-to-electricity conversion efficiency, expressed as a percentage of the theoretical maximum conversion efficiency.

Flash

The Flash option allows you to choose from four subtypes that determine the plant efficiency.

For a description of the conversion system inputs see pages 12-16 of the "Revisions to GETEM Spreadsheet (Version 2009-A15)" document available at http://www1.eere.energy.gov/geothermal/getem_manuals.html.

Temperature Decline

The temperature decline parameters determine when and how often the project will require that new wells be drilled, and are related to the total resource potential specified on the Resource page.

For a description of the temperature decline inputs, see page 9 of the "Revisions to GETEM Spreadsheet (Version 2009-A15)" document available at http://www1.eere.energy.gov/geothermal/getem_manuals.html.

Flash Technology

The two flash technology inputs impact the plant conversion efficiency for the flash conversion type.

Pumping Parameters

The **Production Well Flow Rate** and resource temperature specified on the Resource page dictate how much energy is available to the plant for conversion into electricity. The higher the flow rate, the more steam (or hot water) moves through the system, making thermal energy available for conversion, which, in turn, means fewer wells have to be drilled and therefore a lower capital expense.

The remaining inputs impact the parasitic load for pumping. The **Injection Well Diameter** applies only when the resource type on the Resource page is EGS.

For a description of pumping, see Section 5.7 of the GETEM Technical Reference Manual (Volume I) available at http://www1.eere.energy.gov/geothermal/getem_manuals.html.

For a description of EGS pumping, see Section 6.1.a of the GETEM User's Manual (Volume II), and page 4 of "Revisions to GETEM Spreadsheet (Version 2009-A15)" both available at http://www1.eere.energy.gov/geothermal/getem_manuals.html.

11.1.4 Power Block

The Power Block page allows you to specify the parameters of a power block that converts thermal energy from the geothermal resource to electric energy using a conventional steam Rankine cycle power plant.

The power cycle can use either an evaporative cooling system for wet cooling, an air-cooled system for dry cooling, or a hybrid cooling system with both wet and dry cooling.

The geothermal model runs simulations over the multi-year life of the plant (defined by **Analysis Period** on the Financing page) to account for the decline in geothermal resource. SAM models the geothermal resource decline on a monthly basis.

The two monthly power block options result in a set of twelve calculations for each year in the plant life. The hourly option results in a set of 8,760 calculations for each year. For a project with a 30-year analysis period, the monthly power block option would result in 360 simulations (12 months/year × 30 years = 360 months), and the hourly power block option would result in 262,800 simulations (8,760 hours/year × 30 years = 262,800 hours).

Because it is unlikely that you will have weather data available for each of the years in the analysis period, SAM uses the same weather file for each year. The only value that might change from year to year in the performance model is the resource temperature as the geothermal resource degrades over time. For the hourly simulation option, SAM only calculates the monthly geothermal temperature decline. This is done for two reasons: 1) it helps maintain comparability between the monthly and hourly options; and 2) the resource temperature does not typically change measurably on an hourly basis, but might change from month to month.

Power Block Model

Model

You can choose from two different power block model options:

- The GETEM option calculates the power block's monthly output.
- The Power Block Monthly and Power Block Hourly options calculate either monthly or hourly power block output values, and use a more sophisticated algorithm based on physical principles using the power block model developed for SAM's physical parabolic trough model. For a detailed description, see Chapter 4 of Wagner M, 2008. Simulation and Predictive Performance Modeling of Utility-Scale Central Receiver System Power Plants. Master of Science Thesis. University of Wisconsin-Madison. http://sel.me.wisc.edu/theses/wagner08.zip.

Power Block Design Point

Rated cycle conversion efficiency

The thermal to electric conversion efficiency of the power cycle under design conditions.

Design inlet temperature (ºC)

The heat transfer fluid temperature at the power cycle inlet under design conditions. SAM sets this value to the plant design temperature on the Plant and Equipment page.

Design outlet temperature (ºC)

The heat transfer fluid temperature at the power cycle outlet under design conditions.

Boiler operating pressure (bar)

The steam pressure in the main Rankine cycle boiler at design, used to calculate the steam saturation temperature in the boiler, and thus the driving heat transfer temperature difference between the inlet heat transfer fluid and the steam in the boiler.

Steam cycle blowdown fraction

The fraction of the steam mass flow rate in the power cycle that is extracted and replaced by fresh water. This fraction is multiplied by the steam mass flow rate in the power cycle for each hour of plant operation to determine the total required quantity of power cycle makeup water. The blowdown fraction accounts for water use related directly to replacement of the steam working fluid. The default value of 0.013 for the wet-cooled case represents makeup due to blowdown quench and steam cycle makeup during operation and startup. A value of 0.016 is appropriate for dry-cooled systems to account for additional wet-surface air cooling for critical Rankine cycle components.

Cooling System

Condenser type

Choose either an air-cooled condenser (dry cooling), evaporative cooling (wet cooling), or hybrid cooling system.

In hybrid cooling a wet-cooling system and dry-cooling share the heat rejection load. Although there are many possible theoretical configurations of hybrid cooling systems, SAM only allows a parallel cooling option.

Hybrid Dispatch

For hybrid cooling, the hybrid dispatch table specifies how much of the cooling load should be handled by the wet-cooling system for each of 6 periods in the year. The periods are specified in the matrices. Each value in the table is a fraction of the design cooling load. For example, if you want 60% of heat rejection load to go to wet cooling in Period 1, type 0.6 for Period 1, and then user your mouse to select the hours and months in the schedule that Period 1 applies, and type the number 1. See Time of Delivery Factors for step-by-step instructions for using assigning periods to a schedule matrix.

Directing part of the heat rejection load to the wet cooling system reduces the total condenser temperature and improves performance, but increases the water requirement. SAM sizes the wet-cooling system to match the maximum fraction that you specify in the hybrid dispatch table, and sizes the air-cooling system to meet the full cooling load.

Note. The hybrid dispatch option only works with the hourly power block model. The option does not work with the monthly or GETEM power block model.

Ambient temperature at design (ºC)

The ambient temperature at which the power cycle operates at its design-point-rated cycle conversion efficiency. For the air-cooled condenser option, use a dry bulb ambient temperature value. For the evaporative condenser, use the wet bulb temperature.

Ref. Condenser Water dT (ºC)

For the evaporative type only. The temperature rise of the cooling water across the condenser under design conditions, used to calculate the cooling water mass flow rate at design, and the steam condensing temperature.

Approach temperature (ºC)

For the evaporative type only. The temperature difference between the circulating water at the condenser inlet and the wet bulb ambient temperature, used with the ref. condenser water dT value to determine the condenser saturation temperature and thus the turbine back pressure.

ITD at design point (ºC)

For the air-cooled type only. Initial temperature difference (ITD), difference between the temperature of steam at the turbine outlet (condenser inlet) and the ambient dry-bulb temperature.

Condenser pressure ratio

For the air-cooled type only. The pressure-drop ratio across the air-cooled condenser heat exchanger, used to calculate the pressure drop across the condenser and the corresponding parasitic power required to maintain the air flow rate.

Min condenser pressure

The minimum condenser pressure in inches if mercury prevents the condenser pressure from dropping below the level you specify. In a physical system, allowing the pressure to drop below a certain point can result in physical damage to the system. For evaporative (wet cooling), the default value is 1.25 inches of mercury. For air-cooled (dry cooling), the default is 2 inches of mercury. For hybrid systems, you can use the dry-cooling value of 2 inches of mercury.

Cooling system part load levels

The cooling system part load levels tells the heat rejection system model how many discrete operating points there are. A value of 2 means that the system can run at either 100% or 50% rejection. A value of three means rejection operating points of 100% 66% 33%. The part load levels determine how the heat rejection operates under part load conditions when the heat load is less than full load. The default value is 2, and recommended range is between 2 and 10. The value must be an integer.

11.2 Geothermal Co-production

The Geothermal Co-Production model estimates power output from co-production resources based on the resource temperature and flow rate and the power plant model chosen. The power plant model calculates the plant net power output based on either the thermal efficiency or utilization efficiency assumed for the power plant.

The input page for the geothermal co-production model is:

- Resource and Power Generation

11.2.1 Resource and Power Generation

The Geothermal Co-Production model estimates power output from co-production resources based on the resource temperature and flow rate and the power plant model chosen. The power plant model calculates the plant net power output based on either the thermal efficiency or utilization efficiency assumed for the power plant.

Thermal Efficiency

The thermal or “First Law” efficiency is defined as the ratio of the net rate of work output of the power plant to the net rate of heat input into the power plant:

$$\eta_{th} = \frac{\dot{W}}{\dot{Q}}$$

Where,

- ηth = thermal efficiency
- W dot = rate of net work/power output from power plant, kJ/s
- Q dot = rate of net heat input to power plant, kJ/s

The thermal efficiency represents the amount of thermal energy input into the power plant that is converted to useful work. The rate of heat input to the power plant is calculated from the change in enthalpy of the resource fluid between the inlet and outlet of the power plant:

$$\dot{Q} = \dot{m}[H(T_{in}) - H(T_{out})]$$

Where,

- Q dot= mass flow rate of co-production resource (water from well), kg/s
- H(T) = specific enthalpy of fluid at temperature T, kJ/kg
- Tin = temperature of resource fluid into power plant in degrees Celsius. SAM assumes that the temperature into the power plant is the same as the resource temperature entered under the “specify resource” section
- Tout = plant outlet temperature in degrees Celsius.

When calculating enthalpy, SAM assumes that the co-production resource is pure water and pressure effects are ignored so that enthalpy is a function of temperature only. The correlation for enthalpy is the same as that used in the Geothermal Energy Technology Evaluation Model (GETEM) (http://www1.eere.energy.gov/geothermal/getem.html). The correlation used is a 6th order polynomial of form:

$$Enthalpy = c0 + c1*T + c2*T^2 + c3*T^3 + c4*T^4 + c5*T^5 + c6*T^6$$

Where,

- c6 = 1.0122595469E-14
- c5 = -1.8805783302E-11
- c4 = 1.4924845946E-08
- c3 = -5.9760546933E-06
- c2 = 0.0013462856545
- c1 = 0.83827719984
- c0 = -24.113934502

Utilization Efficiency

The utilization or “Second Law” efficiency is defined as the ratio of the work output of the power plant to the theoretical maximum power that could be extracted from the resource relative to the ambient or dead state, defined by its exergy:

$$\dot{E} = \dot{m}[(H(T_{in}) - H(T_{ambient})) - T_{ambient}(S(T_{in}) - S(T_{ambient}))]$$

Where,

- S(T) = specific entropy of fluid at temperature T, kJ/(kg-ºC)
- Tambient = ambient temperature, degrees Celsius

The utilization efficiency is then defined as:

$$\eta_u = \frac{\dot{W}}{\dot{E}}$$

Where:

- ηu = utilization efficiency

Like with the enthalpy of the fluid, when calculating entropy, SAM assumes that the co-production resource is pure water and pressure effects are ignored so that entropy is a function of temperature only. The correlation for enthalpy is the same as that used in the Geothermal Energy Technology Evaluation Model (GETEM) (http://www1.eere.energy.gov/geothermal/getem.html). The correlation used is a 6th order polynomial of form:

$$Entropy = c0 + c1*T + c2*T^2 + c3*T^3 + c4*T^4 + c5*T^5 + c6*T^6$$

Where,

- c6 = 7.39915E-18
- c5 = -1.29452E-14
- c4 = 8.84301E-12
- c3 = -0.00000000184191
- c2 = -0.00000120262
- c1 = 0.002032431
- c0 = -0.060089552

Choose how to model geothermal production

You can model your system using either a theoretical model or a model based on the performance curves of existing commercial power plants to calculate the plant power output.

Theoretical Model

Thermal Efficiency - MIT Report

Power output is based on the specified resource temperature (assumed to be plant input temperature), specified plant output temperature, and the thermal efficiency defined in Equation 7.1 of the "Future of Geothermal Energy" report published in 2006 by MIT:

$\eta th = 0.0935*T(oC) - 2.3266$

This correlation is based on existing binary hydrothermal power plants with operating temperatures between roughly 100-200 degrees Celsius.

Thermal Efficiency – User Defined

Power output is based on a user defined thermal efficiency curve for the power plant, the specified resource temperature (assumed to be plant input temperature), and specified plant output temperature. You create the thermal efficiency curve using the "Enter curve efficiency" button to input temperature/ thermal efficiency data. The thermal efficiency curve is created from the data points entered by using linear interpolation to estimate the curve between points. Performance beyond the maximum and minimum temperatures is determined by linear extrapolation.

Entering a single temperature/efficiency data point results in a power plant with constant thermal efficiency at all temperatures. Entering two data points gives a linear thermal efficiency curve similar in shape to the MIT correlation described above. More complex curves can be created by entering a large number of data points that approximate the shape of the user-defined curve. In this way, you can define a curve of any shape desired. Data can be input by cutting and pasting values into the "Efficiency Curve" columns.

Utilization Efficiency – User Defined

Power output is based on a user defined utilization efficiency curve for the power plant, the specified resource temperature (assumed to be plant input temperature), and specified ambient temperature. You create the utilization efficiency curve in the same manner as for the thermal efficiency curve described above.

Existing Systems

PureCycle

Thermal efficiency curves for the PureCycle system are based on performance curves published by UTC at (http://www.pratt-whitney.com/StaticFiles/Pratt%20&%20Whitney%20New/Media%20Center/Press%20Kit/1%20Static%20Files/pwps_orc_brochure.pdf). The thermal efficiency curves assume a net power plant output of 260 kW. It is assumed that cooling water is available. You can specify cooling water temperatures from 50-80 oF, consistent with the published performance curves.

Size plant based on resource power potential

You can also specify whether you want to use the system design power output of 260 kW, or to size the power plant specifically to the resource. This is identical to having a power plant that has similar performance characteristics of the PureCycle system but is sized specifically to the defined resource. Such systems are hypothetical and are not actually available commercially, but are included to allow you to determine how having a system with performance similar to available commercial systems but more-closely sized to their resource would affect the economics of their projects.

Specify the number of units

Plant output for each unit is assumed to be the same as that advertised for the commercially available system. If the resource power potential is greater than the design output of the specified units, then the resource is under-utilized and the power output is limited by the number of units. If the resource power potential is less than the design output of the specified units, then the power plant is under-utilized and the power output from the plant will not reach its maximum, but will be limited by the resource. The capital costs for the project will still be based on the plant's design power output. In this way, you can explore how a power plant vs. resource power potential mismatch affects the economics of the system.

A similar comparison can be done with theoretical plants by choosing whether to specify the plant design net output or size it to match the resource power potential.

12 Biomass Power

The biopower model is a performance- and cost-modeling tool for assessing the biomass power resource of a location.

For a basic description of the model, see Biopower Overview.

The biopower input pages are:

- Location and Ambient Conditions: Weather data used by the model and how to specify a weather file.
- Feedstock: Biomass feedstock resource and optional supplemental coal feedstock inputs.
- Plant Specs: Feedstock handling options, combustion system and Rankine cycle parameters.
- Biopower System Cost: Installation and O&M costs.
- Feedstock Costs: Cost of the biomass and optional supplemental coal feedstock.
- Life-Cycle Impacts: Inputs for life cycle emissions analysis.

12.1 Biopower Overview

The biopower model is a performance- and cost-modeling tool for assessing the biomass power resource of a location. SAM can model biopower plants that use crop and wood residues as a feedstock. It can also model a supplementary coal feedstock for a co-fired plant, or completely coal-fed power plant for comparison with a biopower option. You can also specify custom feedstocks.

SAM can access and download data from NREL's Biofuels Atlas (http://maps.nrel.gov/biomass) to quantify the type and amount of biomass available at the location you specify on the Location and Ambient Conditions page.

You specify the basic mass and energy balances for the plant's combustor and steam turbine.

SAM generates performance metrics such as heat rate, thermal efficiency, and capacity factor. It also generates financial metrics such as the levelized cost of energy (LCOE), net present value (NPV), and payback period.

Dedicated biomass power facilities are generally on the order of 1 – 60 MW, but SAM can evaluate plants of any size.

For a technical description of the biopower model, see Jorgenson, J.; Gilman, P.; Dobos, A. (2011). Technical Manual for the SAM Biomass Power Generation Model. 40 pp.; NREL Report No. TP-6A20-52688. http://www.nrel.gov/docs/fy11osti/52688.pdf

To create a case based on the biopower model and run a simulation:

1. Start SAM.
2. Under **Enter a new project name to begin**, type a name for your project. For example, "Biopower System."
3. Click **Create New File**.
4. Under **1. Select a technology**, click **Biomass Power**.
5. Under **2. Select a financing** option, click an appropriate financing option.

   Choose Commercial for a project that serves an electric load and buys and sells electricity at retail rates. Choose one of the utility rates for projects that sell power at a price negotiated through a power purchase agreement.
6. Click **OK**.
7. On the Location and Ambient Conditions page, choose a weather file.
8. Specify options for the financial model as appropriate on the Financing, Incentives, and Depreciation pages.
9. On the Feedstock page, click **Obtain Resource Data** to download data from the NREL Biofuels Atlas database for the location you specified on the Location and Ambient Conditions page. You can also specify other resource properties.
10. Specify parameters for the performance model as appropriate on the Plant Specs page.
11. Specify installation, operation and maintenance, and feedstock costs on the Biopower System Cost and Feedstocks Costs pages.
12. If your analysis involves avoided emissions studies, review and revise the emissions factors on the Life-Cycle Impacts page.
13. Click Run, and review results.

The biopower input pages are:

- Location and Ambient Conditions: Weather data used by the model and how to specify a weather file.
- Feedstock: Biomass feedstock resource and optional supplemental coal feedstock inputs.
- Plant Specs: Feedstock handling options, combustion system and Rankine cycle parameters.
- Biopower System Cost: Installation and O&M costs.
- Feedstock Costs: Cost of the biomass and optional supplemental coal feedstock.
- Life-Cycle Impacts: Inputs for life cycle emissions analysis.

12.2 Feedstock

The Feedstock page inputs define the biomass resource of the location you specify on the Location and Ambient Conditions page, and the physical content of the resource.

For a technical description of the biopower model, see Jorgenson, J.; Gilman, P.; Dobos, A. (2011). Technical Manual for the SAM Biomass Power Generation Model. 40 pp.; NREL Report No. TP-6A20-52688. http://www.nrel.gov/docs/fy11osti/52688.pdf

You can use any combination of the following options to specify the feedstock:

- Download feedstock data from the NREL Biofuels Atlas (http://maps.nrel.gov/biomass) to determine the feedstock available for common agricultural and wood residues at the location you specify on the Location and Ambient Conditions page.
- Specify feedstock availability, obtainability, and moisture content by hand.
- Specify elemental composition and heating values for up to two user-specified feedstocks.
- Specify properties of a supplemental coal feedstock.

Biomass Feedstock Resource

Describes the amount of biomass available as an energy resource within a certain radius of a the location specified on the Location and Ambient Conditions page.

Collection radius, miles

The collection radius defines a circle with the location specified on the Location and Ambient Conditions page at its center.

Increasing the collection radius increases the amount of available biomass, but also causes the distance-dependent feedstock delivery costs (specified on the Feedstock Costs page) to increase. Generally, a collection radius of greater than 50 miles is unrealistic.

Obtain resource data

Downloads data from the NREL Biofuels Atlas. SAM uses location data from the Location and Ambient Conditions page when it queries the biofuels resource database.

For descriptions of the NREL Biofuels Atlas data sources, see the Data Sources tab of the web atlas at http://maps.nrel.gov/biomass.

Resource Available

Quantity of each resource available in bone dry tons/year. When you click **Obtain Resource Data**, SAM automatically populates these values with data from the NREL Biofuels Atlas. You can also specify or edit the values by hand.

Resource Obtainability

The obtainability percentages apply to the quantities under **Resource Available** to define the obtainable resource.

Note. The available resource data from the NREL Biofuels Atlas assume that a certain amount of harvest residue remains on the field to prevent soil erosion and maintain nutrients. The resource obtainability percentages apply to the portion of the residue that does not remain on the field.

Moisture (wet %)

The average annual wet moisture content of the crop or wood residue as collected.

SAM uses the wet basis moisture (Mwb), which is the ratio of the weight of water to the weight of the wet biomass weight.

Biomass moisture can also be quantified using the dry basis moisture (Mdb), which is the ratio of the weight of water to the dry biomass weight. The following equations show the relationship between the two moisture content quantities:

$$Mwb = Mdb \div (1 + Mdb)$$

$$Mdb = Mwb \div (1 - Mwb)$$

Traditional Residues

Traditional residues generally fall into two categories: field residue and process residue.

- Bagasse is a residue that is product of sugarcane and sorghum processing.
- Barley straw, corn stover, rice straw, and wheat straw are all field residues that remain after harvest.
- Forest residues usually refer to lumber that is unfit for sawmill processing, such as smaller-diameter branches or stumps, misshapen trees, and undergrowth that may fuel forest fires.
- Primary mill residues are wastes generated by mill processes.
- Urban wood waste includes prunings from residential areas, as well as woody construction materials and used pallets.

Dedicated Energy Crops

Dedicated energy crops are grown specifically for use as a fuel. These crops typically have high yields and densities per acre.

- Woody crops are trees such as willow and poplar.
- Herbaceous crops are grasses such as miscanthus and switchgrass.

Energy Crop Resource Data for Year

Data from the Billion Ton Update study is available for years between 2012 and 2030.

Obtain energy crop data

Download energy crop data from the Billion Ton Update online database.

User-Specified Biomass Feedstocks

You can specify up to two custom feedstocks for biomass resource for locations with biomass resources not listed under **Traditional Residues** and **Dedicated Energy Crops**.

Specify Additional Feedstocks

Check the box to specify custom feedstocks.

Feedstock Resource

The annual total obtainable resource quantity in dry tons per year.

Moisture Content (% wet basis)

The average annual wet moisture content of the crop or wood residue as collected.

SAM uses the wet basis moisture (Mwb), which is the ratio of the weight of water to the weight of the wet biomass weight. See above for equations relating the wet and dry moisture content.

Input dry higher heating value (HHV)

Choose this option to specify the feedstock's higher heating value in Btu per dry pound.

Calculate HHV based on elemental composition

Choose this option to have SAM calculate a higher heating value based on the elemental composition values you specify.

Carbon content (wt %)

The mass percent carbon content of the feedstock.

This value is used for defining the combustion reaction and determining the higher heating value.

For biomass, typical carbon content is around 45%-50%. For coal, the carbon content may be as high as 75%-80%.

Hydrogen content (wt %)

The mass percent hydrogen content of the feedstock.

SAM uses the hydrogen content in combustion calculations, and to determine the latent heat loss when hydrogen in the sample is combusted.

Hydrogen content for most solid fuels is 5%-6%.

Nitrogen content (wt %)

The mass percent nitrogen content of the feedstock.

The typical nitrogen content for some biomass and coal can be up to 2%. Many biomass types can be as low as 0.1% nitrogen.

Supplemental Coal Feedstock

In some cases, you may be interested in comparing the performance of biomass feedstocks to traditional fossil fuels. Alternatively, for regions of scarce or costly biomass feedstocks, coal may be used to augment plant capacity.

SAM determines whether a plant is co-fired based on the resource availability quantities you specify. If you specify zero for all of the biomass feedstocks, SAM will model the plant as a coal-fired plant with no biomass.

For co-fired plants, SAM assumes direct co-firing, where coal and biomass are fed to the same boiler.

Use a coal feedstock to augment plant capacity

Check this box to model a plant with coal.

To model a coal-only plant, change all of the biomass feedstock availability values to zero.

Bituminous Coal Resource

Bituminous coal is the most prevalent rank of coal in the United States. It has a high heat content and is found mostly in the eastern US.

Sub-bituminous Coal Resource

Sub-bituminous coal has a slightly lower heat content than bituminous coal and is most commonly mined in Wyoming.

Lignite Coal

Lignite coal is the cheapest and lowest quality rank of coal. Lignite coal mining occurs primarily in Texas and North Dakota.

Resource Available

The annual availability of the coal feedstock in dry tons/year.

Higher Heating Value (HHV)

The coal resource higher heating value in Btu/dry pound. The default values are Bituminous = 13272, Sub-bituminous = 10958, and Lignite = 7875.

Moisture (wet %)

The wet-basis moisture content of the coal feedstock in percent. The default values are Bituminous = 10, Sub-bituminous = 25, and Lignite = 39.

Overall Feedstock Characteristics

Total estimated plant capacity with selected feedstock

The estimated nameplate capacity calculated based on type of biomass, amount of biomass, and performance parameters specified on the Feedstock and Plant Specs pages. In order to increase the capacity, the biomass supplied on the Feedstock page must be directly increased.

SAM does not use the estimated max gross nameplate capacity value in simulations. It is shown purely for reference. The simulation engine computes the actual efficiency, whereas the estimated nameplate capacity is based on an estimated efficiency. The simulation engine takes into account variations like ambient conditions or the dispatch schedule. To capture this temporality, the simulation engine averages the hourly efficiencies.

Average HHV and LHV

SAM calculates and displays the weighted average of the HHV and LHV for each feedstock based the obtainable biomass that you specify. Changing the resource availability or obtainability for one or more feedstock changes the average HHV and LHV values.

Typical heating values for biomass are generally between 7000-8000 Btu/lb (or about 16,000 – 19,000 kJ/kg).

Wt frac of total feedstock

The weight of the biomass and coal feedstock as a fraction of the total feedstock weight.

12.3 Plant Specs

The Plant Specs page inputs define the major unit operations that make up a biomass power plant: biomass processing, combustion system and boiler, and steam turbine.

For a technical description of the biopower model, see Jorgenson, J.; Gilman, P.; Dobos, A. (2011). Technical Manual for the SAM Biomass Power Generation Model. 40 pp.; NREL Report No. TP-6A20-52688. http://www.nrel.gov/docs/fy11osti/52688.pdf

Biomass Feedstock Handling

The biopower model has three options for specifying biomass moisture content.

Fed as received

The biomass feedstock does not undergo any substantial drying before being fed to the combustor. This option avoids drying costs but penalizes the boiler efficiency since evaporation of biomass moisture requires energy input.

Allow feedstock to air-dry to atmospheric Equilibrium Moisture Content (EMC)

The biomass is exposed to the ambient atmospheric conditions for a sufficient amount of time to reach EMC. However, moisture composition doesn't change instantly, and thus the equilibrium moisture levels are calculated on a monthly basis.

Dry to specified moisture content

The feedstock handling system includes a dryer as an additional capital expenditure that you specify on the Biopower System Cost page. Adding a dryer also increases the parasitic load of the plant and may add an incremental operation and maintenance cost. Although adding a dryer can increase the boiler efficiency by several percent, dryers are not widely used in practice because of the additional costs and parasitic loads.

Combustion System

SAM can model three common combustion systems encountered in biomass power plants. For a more detailed description of the combustion systems with suggestions for choosing input values, see Section 3.1.2 of the SAM biomass power technical manual referenced at the top of this page.

Grate Stoker Furnace

A grate stoker furnace is designed to feed solid fuel onto a grate where burning occurs, with combustion air passing through the grate. Stokers are generally the least expensive of the three boiler types and are best suited for large fuel feed rates, typically between 75,000 lb/hr and 700,000 lb/hr.

Fluidized Bed Combustor (FBC)

Fluidized bed combustion features a bed of fuel and sand or other inert substance that becomes suspended by the combustion air flowing upward. This technology reduces the fluctuations in steam production associated with changeable feedstocks, and features a lower combustion temperature and reduced formation of pollutants. However, capital costs and O&M costs are typically higher for the FBC than the other combustion systems.

Cyclone Furnace

Cyclone furnaces allow for flexibility in fuel types and increase combustion efficiency over stoker boilers by feeding the fuel in a spiral manner. Additionally, cyclone furnaces are smaller and have a lower capital cost than FBCs.

Note. SAM does not automatically change the cost assumptions on the Biopower System Cost page when you change the combustion system option. Be sure to use costs appropriate for the type of plant you specify.

Boiler Parameters

You can specify the main parameters that determine boiler and furnace efficiency.

Note. The values of the parameters depend on the type of combustor. The default values are for a boiler for a steam grade of 900 F, 900 psig. If you choose a different steam grade, be sure to change the value of the other parameters accordingly.

Steam Grade

The severity of the steam grade is often determined by the type of boiler. For example, lower combustion temperatures in fluidized bed combustors often result in lower steam grades. The steam grade directly determines the enthalpy of the steam produced in the boiler.

Percent excess fed air, %

By convention, the percent excess air is specified on a volumetric/molar basis. Combustion air from the atmosphere is only 21% oxygen by volume (and the balance nitrogen). Therefore, most of the enthalpy losses result from heating the nitrogen that accompanies the combustion oxygen. Increasing the excess fed air percentage decreases the boiler efficiency because more energy is required to heat the combustion air. If the excess air fed air percentage is too low, the fuel will not combust fully and the boiler can emit carbon monoxide and smoke.

Number of boilers

Using fewer boilers reduces installation costs. Using more boilers may also reduce costs by offering the benefit of economies of scale. Typically, small utility scale-sized biopower plants use between one and three boilers.

Flue gas temperature, °F

The flue gas is the mixture of gases exiting the plant through the stack. All useable heat has been collected when the combustion gases reach the specified flue gas temperature. Flue gas heat is often used to preheat other process streams, such as the boiler feedwater. The most efficient boilers utilize as much of the flue gas heat as possible before it exits the plant.

Estimated steam produced, lb/hr steam

This metric is calculated based on the estimated efficiency of the boiler and the enthalpy of the steam produced. The steam produced in the boiler directly powers the steam turbine.

Boiler overdesign factor, %

Boilers are generally oversized to prevent operating above capacity and for the ability to accommodate more biomass throughput. A higher value increases the boiler capital cost. Too low of a value results in lower overall efficiency.

Design capacity of each boiler, lb/hr steam

Boilers are generally oversized to accommodate fluctuations in steam production and to allow for additional capacity. However, highly oversized boilers can result in increased efficiency loss and capital cost. The boiler overdesign factor input will directly adjust the design capacity of each boiler metric.

Estimated Efficiency Losses (HHV)

Dry flue gas losses, %

Combustion air enters the furnace at ambient temperature, where it is immediately subject to preheating by waste process heat. Regardless of how the air is preheated, a significant loss of enthalpy occurs when the combustion gas exits the plant at a much higher temperature than the temperature at which it was fed. The Dry Flue Gas Loss is largely determined by the input percent excess fed air. Combustion air from the atmosphere is only 21% oxygen by volume (and the balance nitrogen). Thus, much of the enthalpy losses result from heating up the nitrogen that accompanies the combustion oxygen.

Moisture in flue, %

Moisture in fuel adversely affects plant efficiency in two primary ways. First, water in biomass imposes extra mass that must be consequently hauled and processed with the biomass itself. Additionally, the water absorbs heat from the combustion reaction that is unlikely to be recovered. Some power plants employ pre-combustion biomass drying to reduce moisture content and efficiency loss in this category. SAM allows the user to add a dryer under the dry to specified moisture content input on the Plant Specs page.

Latent heat, %

Loss of latent heat results when elemental hydrogen in biomass combusts to form water. The water produced will leave the stack at the flue gas temperature as water vapor, thus requiring the latent heat of vaporization of water as well as the sensible heat of the vapor at the flue gas temperature.

Unburned fuel, %

Unburned fuel losses simply result from incomplete combustion in the boiler. In practice, the unburned fuel percentage depends on the type of boiler and excess fed air. This efficiency loss is one of the most difficult to predict, but for well-maintained boilers at proper levels of excess air, the degree of incomplete combustion should be similar among various technologies. Therefore, the boiler type input will determine this value.

Radiation and miscellaneous, %

This category encompasses radiation losses and various other losses that are difficult to quantify or predict, such as moisture in air, sensible heat in ash, and radiation in ash pit. The other derates are lumped together under a “manufacturer’s margin” derate, which is taken to be 2.03%. For more information about this category, consult the Technical Manual.

Total Boiler Efficiency (HHV Basis), %

Total Boiler Efficiency =100 - Dry Flue Gas Losses - Moisture in Fuel - Latent Heat - Unburned Fuel - Radiation and Miscellaneous

Steam Rankine Cycle

Steam produced in the boiler at the specified grade drives a steam turbine and electric generator to convert the thermal energy of the steam to electricity.

Note. The biomass power's steam turbine model is based on the empirical parabolic trough model's power block model. For a description of how SAM uses the part-load and temperature adjustment coefficients, see Power Block Simulation Calculations.

Estimated max gross nameplate capacity, kW

The estimated nameplate capacity calculated based on type of biomass, amount of biomass, and performance parameters specified on the Feedstock and Plant Specs pages. In order to increase the capacity, the biomass supplied on the Feedstock page must be directly increased.

SAM does not use the estimated max gross nameplate capacity value in simulations. It is shown purely for reference. The simulation engine computes the actual efficiency, whereas the estimated nameplate capacity is based on an estimated efficiency. The simulation engine takes into account variations like ambient conditions or the dispatch schedule. To capture this temporality, the simulation engine averages the hourly efficiencies.

Rated cycle conversion efficiency

The rated efficiency of the turbine, equivalent to average conversion efficiency of the steam's thermal energy to electricity.

Minimum load

Most turbines do not operate below a certain fraction of full load, when the turbine performance is difficult to predict and the economics may become unfavorable. The fractional value for minimum load represents the threshold below which the turbine will not operate.

Max overdesign operation

Prevents the turbine from operating above a certain fraction of the design load.

Power cycle design temperature, °F

The design temperature of the turbine. The actual efficiency of the turbine is temperature dependent. Fluctuations of the temperature cause changes in the efficiency.

Part Load and Temperature Efficiency Adjustments

The effect of temperature and part load on efficiency can be adjusted with the coefficients F0 – F4. These coefficients define a polynomial equation for adjusting the amount of heat supplied to the power block based on deviations from full load and design temperature.

Temperature Correction Mode

Choose either an air-cooled condenser (dry bulb) or evaporative cooling (wet bulb).

Dry-bulb temperature refers to the thermodynamic temperature of the air that can be found with a standard thermometer. The wet-bulb temperature also captures the moisture content of the air, and is always less than the dry-bulb temperature (except at 100% relative humidity, when the two are equal).

Evaporative cooling uses the evaporation of water to cool the process condensate to near the wet-bulb temperature. Dry cooling uses air and thus the minimum heat rejection is the dry-bulb temperature.

Typically, air-cooled systems require more capital, are less thermodynamically efficient, and use more energy. However, evaporative cooling demands more water and might not be suitable in some regions.

Parasitics

Parasitic load (% of nameplate), %

The electric load requirement as a percentage of the nameplate capacity for plant loads such as pumps, compressors, fans, lighting, etc.

Total plant parasitic load, kWe

Total Plant Parasitic Load (kW) = Parasitic Load (% of Nameplate) ÷ 100 × Estimated Max Gross Nameplate Capacity (kW)

Time of Dispatch Schedule

The Time of Dispatch controls allow you to specify at what times the plant operates, and at what fraction of its nameplate capacity.

If you want the plant to operate at its full capacity at all times, do not check **Enable Time of Dispatch Schedule**.

Check **Enable Time of Dispatch Schedule** to specify fractional generation levels for up to nine periods. For each period, you can specify a fraction of the nameplate capacity.

Use your mouse to select blocks of hours in the schedule matrix and type a period number to specify the hours of each month that the period applies. For example, to specify the hours for Period 2, use your mouse to select a block of hours, and then type the number 2. See Time of Delivery Factors for step-by-step instructions for using assigning periods to a schedule matrix.

You can use the dispatch schedule to model:

- Scheduled seasonal outages by specifying a fraction of zero for times when the plant will be down.
- Periods of high demand when the plant can operate above its nameplate capacity, for example during summer months.

Note. If you specify a Fractional Generation value greater than the Max Over Design Operation value, the simulation will fail.

- Periods of feedstock shortages and surpluses when the plant is forced to operate below or above capacity.

Ramp Rate

SAM provides three options for specifying the ramp rate, or the rate at which a plant can increase or decrease its generation.

Do not specify ramp rate

Assumes that the plant can operate at the fraction of nameplate capacity in each hour that the fraction applies. This option is appropriate when the ramp rate is less than SAM's hourly simulation time step, or when you model the ramp rate explicitly using a series of ramp rates over a period of hours.

Specify ramp rate in kW per hour

Model the ramp rate as an energy requirement as a kW per hour value during periods when the plant operates at a fraction of the nameplate capacity.

Specify ramp rate in percent of capacity per hour

Model the ramp rate as an energy requirement as a percentage of the nameplate capacity during periods when the plant operates at a fraction of the nameplate capacity.

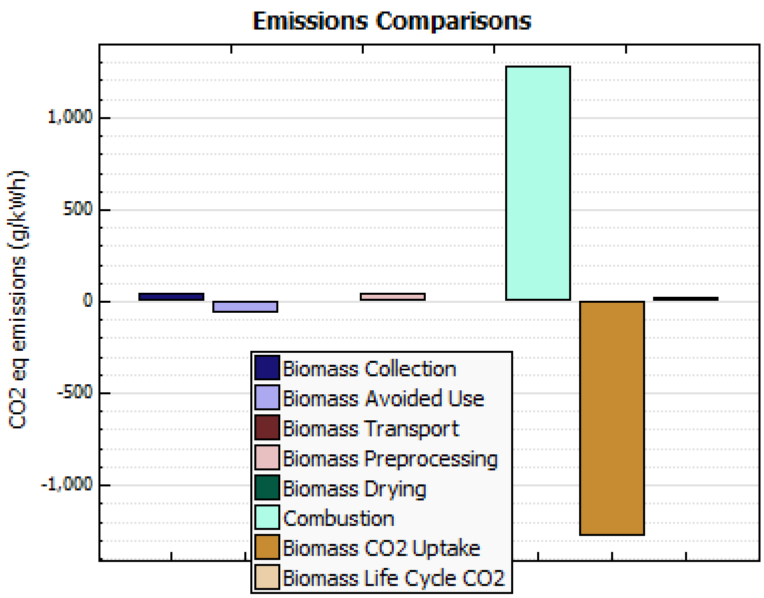
12.4 Life-Cycle Emissions

The Life-Cycle Impacts page allows you to specify inputs for a set of life-cycle greenhouse gas emissions calculations for the biomass supply chain. You can use these inputs to estimate the independent contributions of biomass collection, transport, pre-processing, combustion, and CO2 re-uptake on the life-cycle carbon dioxide emissions of the project.

For a technical description of the biopower model, see Jorgenson, J.; Gilman, P.; Dobos, A. (2011). Technical Manual for the SAM Biomass Power Generation Model. 40 pp.; NREL Report No. TP-6A20-52688. http://www.nrel.gov/docs/fy11osti/52688.pdf

> **Note**. The life-cycle impacts calculations are independent of the power plant energy modeling calculations. The inputs on the life-cycle impacts page are for a separate set of calculations than the inputs on the Feedstock and Plant Specs pages.

After running simulations, SAM displays a graph on the Results page similar to the following one showing the percent difference in CO2 equivalent emissions from the different sources.



Inside farmgate

Diesel-powered biomass collection vehicle / Biodiesel-powered biomass collection vehicle

Specifies the type of fuel used to power the field biomass collection vehicle. Please note that this input only affects the life-cycle analysis portion of the model.

Assume biomass was not grown dedicated to power (waste)

Specifies the intended use of the biomass. When waste biomass goes unused (e.g., in a landfill), it undergoes decomposition which can result in methane emissions. If a biopower plant utilizes biomass that would otherwise decompose, the plant receives a greenhouse gas "credit" for avoiding more harmful methane emissions.

Clearing this box signifies that the biomass was grown explicitly for power generation, meaning that no decomposition emissions were avoided.

From farmgate to biopower facility

Diesel-powered vehicle for truck transport / Biodiesel-powered vehicle for truck transport

This input specifies the type of fuel used to power the vehicle used to haul the biomass from the farmgate to the biopower facility. Please note that this input only affects the life-cycle analysis portion of the model. For instance, if using biodiesel increases the delivery cost of biomass, you must reflect the increased cost on the Feedstock Costs page.

One-stage truck transport (no separate pre-processing facility) / Two-stage truck transport (separate pre-processing facility)

Occasionally, regional biomass will be pre-processed at a separate facility before being used in a biopower plant. This input

considers the vehicle-miles traveled for biomass to arrive at the biopower plant. For instance, the vehicle-miles traveled may increase if the biomass must travel to a pre-processing facility that is not on the way to the plant. Again, please note that this input only affects the life-cycle analysis portion of the model.

Enable long-distance transport after xx miles: Freight rail transport for long distances / Freight barge transport for long distances

Currently, most biomass is transported via truck for short distances. However, after a certain amount of miles, rail or barge transport may become more economical. This option allows you to see the emissions benefits of using a more efficient transport option for a specified "longer" distance. Again, please note that this input only affects the life-cycle analysis portion of the model. For instance, if using railroad transport decreases the delivery cost of biomass, you must reflect the changed cost on the Feedstock Costs page.

Preprocessing Options

Pre-processing includes grinding or chipping / Pre-processing includes pelletization

Most biomass typically undergoes some pre-processing before being fed into a biopower plant. The pre-processing may include light grinding or chipping, heavy grinding, and/or pelletization. In most cases each pre-processing step would be subsequent to the previous step. For example, biomass pelletization only occurs after heavy grinding.

Pre-processing increases the resources required to prepare the biomass and thus increase the emissions impact of biomass power

Electricity grid carbon intensity, g CO2 eq/kWh

This input allows you to specify the carbon intensity of the electricity being used for pre-processing, fertilizer production, and biomass storage.

For example, if a carbon-efficient technology is used to generate the power required for pre-processing, the overall greenhouse burden of the biopower facility would be less than a less efficient technology.

You can choose from several US regional values with sample values for 100% coal and 100% renewable energy. The default value is the 2010 United States average.

13 Financial Models

SAM's financial models calculate project cash flows and financial metrics for the financing option you choose in the Technology and Market window.

For a description of the different financing options, see Financing Overview.

SAM displays different variables on the Financing page, depending on the financing option you choose:

- Residential
- Commercial
- Commercial PPA
- Utility IPP

For projects with more complex financial structures, SAM displays the Financing page with inputs for the advanced utility IPP financing options:

- Single Owner
- All Equity Partnership Flip
- Leveraged Partnership Flip
- Sale Leaseback

The financial models use inputs from the Financing pages listed above, and from the following input pages:

- System costs
- Incentives
- Depreciation

For residential and commercial models include additional use inputs for retail electricity rates.

The utility and commercial PPA models may use inputs from the Time of Delivery Factors page.

13.1 Financing Overview

SAM's financial models calculate a project's cash flow over an analysis period that you specify. The cash flow captures the value of electricity generated by the system and incentives, and the cost of installation, operation and maintenance, taxes, and debt.

> **Note.** SAM is designed to calculate the value of electricity generated by a system. The economic metrics it reports are based on units of electrical energy rather than thermal energy. The solar water heating model calculates the value of electricity saved by the system, assuming that heat from the system displaces heat that would be generated by a conventional electric water heater without the solar system.

The financial models can represent two main types of projects:

- Residential and commercial projects that buy and sell electricity at retail rates and displace purchases of power from the grid.

- Utility and commercial PPA projects that sell electricity at a wholesale rate to meet internal rate of return requirements.

Background

SAM's residential, commercial, and utility IPP financial models are based on principles described in Short W et al, 1995. Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies. National Renewable Energy Laboratory. NREL/TP-462-5173. http://www.nrel.gov/docs/legosti/old/5173.pdf

The advanced utility models (single owner, leveraged partnership flip, and sale leaseback) models are based on work done by a team of analysts to adapt recent developments in renewable energy finance to SAM.

Annual Electrical Output

The cash flow models for the different financing options require a single value representing the system's total electrical output in a single year to determine the project's annual income (utility and commercial PPA) or savings (residential and commercial). The performance model calculates this value by adding up the results of an hourly simulation of the system's performance over the year. The weather data and system's technical specifications from the performance model's input pages determine the annual output of the system.

When you specify a **Year-to-year decline in output** value on the Performance Adjustment page, SAM reduces the annual output from year to year in Years Two and later. When the value rate is zero, SAM assumes that the annual output is the same for all years in the analysis period.

Note. For geothermal systems, SAM uses a different method for calculating annual output that depends on the long-term resource data rather than the **Year-to-year decline in output value**.

Financial Model Inputs

SAM's input pages are organized so that groups of related input variables appear together. Variables on the following input pages are inputs to the financial models. The input pages that are available depend on the financing option:

- System Costs (all options): Installation and operation and maintenance (O&M) costs for the project.
- Performance Adjustment (all options)
- Financing (all options): Financial structure, debt parameters, tax and insurance rates, partner shares, etc.

  Residential

  Commercial

  Utility IPP and Commercial PPA

  Utility Single Owner

  Utility All Equity Partnership Flip

  Utility Leveraged Partnership Flip

  Utiltiy Sale Leaseback
- Time of Delivery Factors (utility and commercial PPA, except for CSP systems): Time-dependent PPA price adjustment factors.
- Incentives (all options): Tax credits and cash incentives.
- Depreciation (utility and commercial PPA): Accelerated depreciation tax benefit.
- Utility Rate (residential and commercial options): Retail electricity pricing.
- Electric Load (residential and commercial options): Building electric load.

Financial Model Results

The Results page displays the cash flow and economic metrics that summarize the cash flow, such as the levelized cost of energy, net present value, and others depending on the financial model.

Incentives

For all of the financing options in SAM, you can include different combinations of incentives, which may be either tax credits or cash payments. SAM allows for modeling of separate federal and state income tax credits, and for cash incentives from up to four different entities.

Note. Although the incentive options are based on those available in the United States, and use U.S. nomenclature, it may be possible to use the options to model incentives available in other countries.

Tax credits reduce a project's annual tax payment, and are specified on the Incentives page. Tax credits can apply to federal income tax, state income tax, or both. The options are:

- Investment tax credits (ITC) based on the cost of installing equipment.
- Production tax credits (PTC) based on the amount of electricity generated by the project.

Cash incentives are payments to the project specified on the Incentives page. The options are:

- Investment-based incentives (IBI) based on the cost of installing equipment.
- Capacity-based incentives (CBI) based on the size of the system.
- Production-based incentives (PBI) based on the amount of electricity generated by the project.

For commercial and utility projects, SAM also models accelerated depreciation (including MACRS), specified on the Depreciation page.

Residential and Commercial Projects

In SAM, residential and commercial projects (excluding Commercial PPA) buy and sell power at retail rates. They may be financed through either a loan or cash payment (0% debt fraction). These projects recover investment costs by selling electricity at rates established by the electricity service provider. SAM calculates metrics for these projects at the project level, assuming that a single entity develops, owns, and operates the project.

For residential and commercial projects, SAM calculates the project's levelized cost of energy, which represents the cost of installing and operating the system, including debt and tax costs, and accounting for incentives. The model also calculates the net present value of the after tax cash flow, and a payback period representing the number of years required for the cumulative after tax cash flow to cover the initial equity investment in the project.

Commercial projects may qualify for tax deductions under the Modified Accelerated Depreciation Schedule (MACRS) described in the United States tax code. SAM provides options for specifying custom depreciation schedules in addition to the MACRS mid-quarter and half-year schedules on the Depreciation page.

Residential and commercial projects are typically smaller than 500 kW, although SAM does not restrict system sizes, so it is possible to model any size system using either the residential or commercial financing option.

SAM's Utility Rate page provides a range of options for specifying the utility rate structure for a project. The rate structure may include any of the following:

- Flat buy and sell rates (with or without net metering)

- Time-of-use energy charges
- Monthly demand charges (either fixed or time-of-use)
- Tiered rates
- Fixed monthly charges

For projects with demand charges and tiered rates, SAM requires electric load data, which is specified on the Electric Load page.

Commercial PPA Projects

Commercial PPA projects sell electricity at a price negotiated through a power purchase agreement (PPA). SAM either calculates a power purchase price (PPA price) given a target minimum IRR, or calculates the IRR for a given PPA price with options for optimizing the debt fraction and PPA escalation rate to minimize the PPA price.

For commercial PPA projects, SAM calculates the PPA price, IRR, NPV, and other metrics for the project as a whole, assuming that a single entity participates in the project and has sufficient tax liability to absorb tax credits and depreciation benefits.

Commercial PPA projects are typically larger than 500 kW, although SAM does not restrict system sizes, so it is possible to model any size system using either the residential or commercial financing option.

> **Note.** The Commercial PPA and Utility IPP financing options in SAM are mathematically identical. The only difference between the two models is that the Utility IPP option offers two financial optimization settings on the Financing page that are not available for the Commercial PPA option.

Utility Projects

Utility projects sell electricity at a price negotiated through a power purchase agreement (PPA) to meet a set of equity returns requirements, and may involve one or two parties.

SAM provides options for calculating a power purchase price given a target internal rate of return, or for calculating the rate of return given a power purchase price. An optional annual escalation rate allows for pricing that varies annually, and optional time-of-delivery (TOD) factors allow for pricing that varies with time of day.

For utility projects, depending on the options you choose, SAM either calculates an electricity sales price (PPA price) or IRR. For the advanced utility options, SAM reports IRRs and NPVs for the project as a whole, and as appropriate, for each project partner.

The utility market options are typically appropriate for large-scale projects because of the costs associated with financial customization. However, developers of smaller commercial projects are experimenting with lower cost approaches, such as using standardized versions of some of the advanced financing structures, financing projects on an aggregated basis, seeking corporate financing rather than project-level financing, and partnering with community-based lending institutions and investors. Because SAM does not restrict the size of the system, it is possible to use these financing structures with any size of system.

The five options available in SAM for utility projects are described below.

All Equity Partnership Flip, Leveraged Partnership Flip

The All Equity Partnership Flip and Leveraged Partnership Flip options are two-party projects that involve equity investments by a project developer and a third party tax investor. The tax investor has sufficient tax liability from its other business operations to utilize any tax benefits (tax credits and depreciation deductions) fully in the years in which the project generates the benefits. The project sets up a limited liability entity, and once the project begins generating and selling electricity, all of the project's net cash flows and tax benefits are passed through this entity to its owners. The project allocates a majority of the cash and tax benefits to the tax investor when the project begins operation and until the tax investor receives a pre-negotiated after-tax IRR, also known as the flip target. Once the flip target is reached, a majority of the cash and any remaining tax benefits are allocated to the developer.

Sale Leaseback

The Sale Leaseback option is another two-party structure that involves a tax investor purchasing 100% of the project from the developer and then leasing it back to the developer. This structure differs from the partnership flip structures in that the tax investor and the developer do not share the project cash and tax benefits (or liability). Instead, each party has its own separate cash flow and taxable income. The purchase price paid by the tax investor is equal to the total project cost, less a lease payment and the value of working capital reserve accounts. The developer typically funds the reserve accounts to ensure it has some financial exposure. The tax investor receives lease payments from the developer and any ownership-related incentives such as the tax credits, incentive payments, and the depreciation tax deductions. The developer operates the project and keeps any excess cash flow from operations, after payment of all operating expenses and the lease payments. This provides the developer with an incentive to operate the project as efficiently as possible.

Note. SAM assumes that the tax investor receives the ITC in the sale leaseback structure. SAM does not model alternative lease structures that treat the ITC differently.

Single Owner, Independent Power Producer

In the Single Owner and Independent Power Producer options, one entity owns the project and has sufficient tax liability to utilize the tax benefits. This structure is less complicated than the Partnership Flip and Sale Leaseback structures because there is no need to allocate cash and tax benefits to different partners. The owner may be either the original developer or a third-party tax investor that purchases the project from the developer. (See above for a discussion of the differences between the Single Owner and Independent Power Producer options.)

Below is a table summarizing the five structures.

	All Equity Partnership Flip	Leveraged Partnership Flip	Sale Leaseback	Single Owner, Utility IPP
Equity Owners	Tax investor Developer	Tax investor Developer	Tax investor (Lessor)	Developer (third party if sold)
Project Debt	No	Yes	No	Optional (owner choice)
Return Target	Tax investor after-tax IRR (Flip Target)	Tax investor after-tax IRR (Flip Target)	Lessor after-tax IRR	Owner after-tax IRR
Cash Sharing	Pre-Flip: Bifurcated Post-Flip: Primarily developer	Pre-Flip: Pro rata Post-Flip: Primarily developer	Lessor: Lease payment Lessee: Project margin	Owner receives 100% of project cash

Tax Benefit Sharing	Pre-Flip: Primarily tax investor Post-Flip: Primarily developer	Pre-Flip: Primarily tax investor Post-Flip: Primarily developer	Tax investor and developer have different taxable incomes ITC and Depreciation goes to tax investor	Owner receives 100% of project tax benefits

Advanced Utility and Utility IPP/Commercial PPA Options

The old financing options, commercial PPA and utility IPP, available in the current version of SAM, are based on the financing options available in SAM 2010.11.9 and older versions. They are included in the current version to allow for comparison of results with older versions of SAM:

- Commercial PPA in the current version is equivalent to Commercial Third Party in previous versions.
- Utility IPP in the current version combines the Independent Power Producer, Time of Dispatch, and First Year Bid Price financing options from previous versions into a single model.

The new advanced utility financing options (All Equity Partnership Flip, Leveraged Partnership Flip, Sale Leaseback, and Single Owner) are options added since SAM 2011.5.4 may better represent actual project financing structures for renewable energy projects than the older Utility IPP option.

All of the utility financial options assume that a project sells electricity at a price negotiated determined by a power purchase agreement (PPA).

The following list summarizes some of the differences between the old and new financing options:

- Debt fraction is an input for the commercial PPA and utility IPP options. For the single owner and leveraged partnership flip options that involve debt, the debt fraction is a result that SAM calculates based on the debt service coverage requirements you specify as an input on the Financing page, and the available cash in the project cash flow.
- The advanced utility options include structures with two partners, and report IRRs, NPVs, and cash flows for each partner. The commercial PPA and utility IPP financing options report only the total project IRR, NPV, and cash flow.
- The single owner and utility IPP options model the same financing structure: A project financed with debt and involving a single entity that develops and operates the project and receives all project income and benefits. The single owner option is more representative of actual projects. The utility IPP option may be suitable for basic preliminary analysis before some of the details required by the single owner option are known.
- The advanced utility options allow you to specify a reserve account for major equipment replacement that is not available in the commercial PPA and utility IPP options.
- The advanced utility options include inputs for bonus depreciation and more sophisticated handling of depreciation with tax credits and cash incentives than the commercial PPA and utility IPP options.

The commercial PPA and utility IPP models have been updated since SAM 2010.11.9. Improvements include:

- You can specify whether the PPA price is an input and IRR a result, or IRR is an input and PPA price a result using the Solution Mode option on the Financing page.
- The utility IPP model allows you to model a PPA price with time-of-delivery factors, where the negotiated power price varies based on a pre-determined time-of-day schedule. (TOD factors were available for the Time of Dispatch and Bid Price options in previous versions.) For the concentrating solar power technologies, you specify the TOD factors on the Thermal Energy Storage page. For other technologies, see the Time of Delivery Factors page.

- The construction period financing cost includes the option to specify an up-front fee based on the approach used in the new financing models.
- The property tax calculation allows you to specify the property's assessed value as a percentage of the total installed cost, and to specify an annual rate of decline in the assessed value. Previous versions assumed that the assessed value was equal to the total installed cost throughout the analysis period.

13.2 Performance Adjustment

To view the Performance Adjustment page, click **Performance Adjustment** in the main windows navigation menu. The Performance Adjustment page displays input variables that impact the system's total annual electric output.

The performance adjustment variables allow you to model reductions in the system's output due to maintenance down times (availability), system shutdowns required by the grid operator (curtailment), annual reduction in system output due to aging of equipment (degradation), or any other factor that may cause the energy delivered to the grid to be less than the energy value that SAM's performance model calculates.

SAM's performance model calculates the system's net hourly electrical output over a single year. The sum of these hourly values is the system's net annual electrical output. The financial model applies the adjustment factors to the net values to determine the amount of electricity delivered by the system to the grid, and uses this value to determine the monetary value of the electricity used in the financial metric calculations.

The following list shows some examples of how to use the Performance Adjustment variables for different applications:

- Unscheduled maintenance results in a 96% availability for the system: Specify a value of 96 for **Percent of annual output**.
- The system is scheduled for maintenance between 8 am and noon for one week in October: Use the **Hourly Factors** table to specify a value of 0.20 for the October hours of 8 am, 9 am, 10 am, 11 am, and 12 pm to approximate the reduction in output during that time frame, assuming that there are 5 weeks in October.
- The grid operator curtails the system for one week during the month of April: In the **Hourly Factors** table, specify values of 0.25 for the April hours of 12 am through 11 pm, assuming that April has 4 weeks.
- A wind project is in a region with transmission constraints that the project expects will cause curtailment of 5% of the system's electrical output starting in Year 6 of the project life: Use the **Percent of total annual output** annual schedule to specify values of 100 for Years 1 through 5, and 95 for Years 6 and later.
- The inverter in a photovoltaic system is replaced in Year 15 with a 5% more efficient model than was originally installed in Year 0: Use the **Percent of annual output** annual schedule to specify values of 100% for Years 1 through 14, and 105% for Years 15 and later.
- The module output in a photovoltaic system degrades at an annual rate of 0.5%: For **Annual decline in output**, specify a value of 0.5. This is only an approximation of the module degradation rate because SAM applies it to the system's AC output. You may want to adjust the degradation rate by the inverter's nominal efficiency for a more accurate representation of the module degradation rate.

Notes.

For the solar water heating model, the performance model calculates the electrical energy saved by the system rather than electricity generated by the system.

For the geothermal power model, the performance model calculates the electricity generated by the system in each month over its lifetime rather than hourly over a single year. The **Annual decline in output** variable is not available for geothermal systems because the model calculates the system's electrical output from year to year.

System Output Adjustments

Percent of annual output (%)

SAM multiplies the net annual electrical output by the percentage that you specify. For example, a value of 95% for a system with a net annual output of 100,000 kWh results in a delivered electrical output of 95,000 kWh for each year.

If you assign percentages to specific years using an annual schedule (see below), SAM applies the percentage the year 1 net annual output value to calculate each year's delivered annual output value. For example, if you specify 100% for years 1 through 5, and 95% for years 6 and later for the system with a net annual output of 100,000 kWh, the delivered annual output is 100,000 kWh in years 1 through 5, and 95,000 kWh in years 6 and later.

Annual decline in output (%)

SAM applies the percentage to the system's total annual net electrical output value in years 2 and later. For example, a value of 1% for a system with a net annual output of 100,000 kWh results in delivered annual output values of 100,000 kWh in year 1, 99,000 kWh in year 2, 98,010 kWh in year 3, 97,029.9 kWh in year 4, etc.

If you assign values to specific years using an annual schedule, SAM applies the decline in output rate to the year 1 annual output value, not to the previous year's value.

Hourly Factors (24-hour profile for each month)

SAM uses the table to determine what factor to apply to each hour's net electrical output value. For example, a value in the table of 0.75 for 10 am in October for a system with net output of 1,000 kWh at 10 am on October 5, and 1,500 kWh at 10 am on October 6 would result in a delivered electrical output of 1,000 kWh × 0.75 = 750 kWh at 10 am on October 5, and 1,500 kWh × 0.75 = 1,125 kWh at 10 am on October 6.

Note. If you use combinations of performance adjustment values, SAM multiplies the resulting percentages and factors. For example, if you specify a **Percent of annual output** of 95%, and an **Hourly Factor** of 0.75 for 10 am in February, SAM reduces the net electrical output for that hour by 0.95 × 0.75 = 0.7125.

Performance Adjustments in Results

The annual energy value that SAM reports in the Metrics table and for Year 1 in the cash flow table Energy row is the product of **Percent of annual output** and the sum of hourly delivered energy values reported in the tables and time series graphs of performance model results. This annual energy value accounts for the **Percent of annual output** and **Hourly Factors** adjustments, but not the **Annual decline in output** factor, which only applies to Years 2 and later of the cash flow.

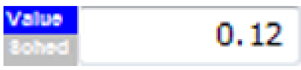
The "delivered energy" values that SAM reports in monthly and hourly tables and time series graphs of performance model results account for the **Hourly Factors** adjustments, but not **Percent of annual output** or **Annual decline in output** factors.

The Energy values that SAM reports in the cash flow table for Years 2 and later accounts for all of the performance adjustment factors, including the **Annual decline in output** factor.

Annual Schedules

Variables with an annual schedule option have a small Value / Sched button next to the variable label. The variable's current mode is indicated in blue.

When the word "Value" is highlighted in blue, you define the variable's value as a single number.



You can use an annual schedule to enter annual values either by hand, typing values or pasting values from a spreadsheet or text file. You can also exchange data from an annual schedule with an Excel worksheet, see Excel Exchange for details.

Note. When you specify rates using an annual schedule, SAM applies the rate to the year 1 value. For example, an **Annual decline in output** value of 0.5% for year 5 would when the year 1 net annual output is 10,000 kWh would result in a delivered annual output value of (1 - 0.005) × 10,000 kWh = 9,950 kWh in year 5.

To enter year-by-year values by hand:

1. Click Sched to change the variable's mode from a single value to annual schedule mode. SAM displays the Edit button.

2. Click **Edit** to open the Edit Schedule window.
3. In **# Values**, type the number of years for which you want to assign values. Typically, this number should be equal to or less than the number of years in the Analysis Period defined on the Financing page.

Important Note. If you specify a number greater than the number of years in the analysis period, SAM ignores any values in the table for years after the end of the analysis period, which does not affect analysis results. However, if you specify a number less than the analysis period, SAM assigns a zero to each year after the number of years you specify, which may cause unexpected results.

4. For each year in the schedule, type a value. For **Percent of annual output**, the value should be a percentage of the system's net annual electrical output. For **Annual decline in output**, the value should be a percent reduction in the net output.

   You can also copy a row of values from Excel, or a line of comma separated values from a text file to your computer's clipboard, and click **Paste** to paste them into the table.
5. Click **Accept** to return to the Performance Adjustment page.

13.3 Residential

This topic describes the inputs on the Financing page for the Residential financing option. For a general description of financial structures SAM can model, see Financing Overview.

SAM displays results of the financial model in the cash flow. See Cash Flow Variables for details.

Loan Type

Standard Loan

For the standard loan option, loan interest payments are not tax deductible.

Mortgage

For the mortgage option, loan interest payments are tax deductible.

Residential Loan Parameters

Note. For the residential mortgage and commercial financing options, SAM deducts loan interest payments from state and federal income taxes. For the residential loan option, SAM does not deduct loan interest payments. For details see, the project cash flow on the Results page.

Debt Fraction

Percentage of the total installed cost to be borrowed.

For example, specifying a debt fraction of 25% means that the project borrows 25% of the total installed cost amount shown on the system costs page for a 25/75 debt-equity ratio.

Loan Term

Number of years required to repay a loan. Note that this value is different than the analysis period.

Loan Rate

Annual loan interest rate.

Principal Amount

The loan principal amount, or amount borrowed.

This is a calculated value that you cannot directly edit. To change the value, change either the value of the debt fraction or a cost on the System Costs page.

Principal Amount ($) = Total Installed Cost ($) × Debt Fraction (%)

Where *Total Installed Cost* is from the System Costs page.

WACC

The Weighted Average Cost of Capital (WACC) is defined as the minimum return that the project must earn to cover financing costs.

SAM displays the WACC for reference. It is not used in any calculations.

This is calculated value that you cannot directly edit. To change its value, change one of the parameters described in the following equation:

WACC = Real Discount Rate × (1 - Debt Fraction) + (1 - Effective Tax Rate) × Loan Rate × Debt Fraction

The effective tax rate is a single number that includes both the federal income tax rate and state income tax rate. SAM uses the effective tax rate for several calculations requiring a total income tax value:

Effective Tax Rate = Federal Tax Rate × (1 - State Tax Rate) + State Tax Rate

Analysis Parameters

The analysis parameters specify the analysis period, inflation rate and discount rate.

Analysis Period

Number of years covered by the analysis. Typically equivalent to the project or investment life. The analysis period determines the number of years in the project cash flow.

Inflation Rate

Annual rate of change of costs, typically based on a price index. SAM uses the inflation rate to calculate the value of costs in years two and later of the project cash flow based on Year One dollar values that you specify on the System Costs page, Financing page, Utility Rate page, Incentives, or pages.

The default value of 2.5% is based on consumer price index data from the U.S. Department of Labor Bureau of Labor Statistics, and is the average of the annual average consumer price index between 1991 and 2012.

Real Discount Rate

A measure of the time value of money expressed as an annual rate. SAM uses the real discount rate to calculate the present value (value in year one) of dollar amounts in the project cash flow over the analysis period and to calculate annualized costs.

Note. For projects with one of the Utility or Commercial PPA financing options, SAM includes both a discount rate and internal rate of return (IRR) in the analysis. For these projects, the discount rate represents the value of an alternative investment, and the IRR can represent a profit requirement or the risk associated with the project. For example, the IRR may be higher than the discount rate for a renewable energy project with higher risk than an alternative investment.

Nominal Discount Rate

SAM calculates the nominal discount based on the values of the real discount rate and the inflation rate:

Nominal Discount Rate = (1 + Real Discount Rate) × (1 + Inflation Rate) - 1

Tax and Insurance Rates

Federal and State Income Tax Rates

The annual federal and state income tax rate applies to taxable income and is used to calculate tax benefits or liabilities.

For all projects, taxable income includes income from any incentives marked on the Incentives page as taxable.

For residential and commercial projects, SAM does not consider the value of electricity saved by the system to be income. However, for commercial projects, because those savings represent the value of electricity purchases that would have been a tax-deductible operating expense to the commercial entity, SAM does reduce the project after-tax cash flow by the amount of federal and state income tax on the value of the electricity. In other words, with the renewable energy system in place, the commercial entity must pay tax on that portion of its income that it would have deducted as an operating expense.

For commercial PPA and utility IPP projects, the energy value represents electricity sales that are taxable income.

Sales Tax

The sales tax is a one-time tax that SAM includes in the project's total installed cost. SAM calculates the sales tax amount by multiplying the sales tax rate on the Financing page by the rate you specify under Indirect Capital Costs and the Total Direct Cost on the System Costs page.

For tax purposes, because SAM includes the sales tax amount in the total installed cost, it treats sales tax as part of the cost of property. For projects with depreciation (Commercial and Utility financing options only), SAM includes the sales tax amount in the depreciable basis. See IRS Publication 551, Basis of Assets, for more details.

Some states and other jurisdictions offer a sales tax exemption for renewable energy projects. To model a sales tax exemption in SAM, reduce the sales tax percentage as appropriate. For example, for a 100% sales tax exemption, enter a sales tax rate of zero.

For projects with debt, because SAM includes the sales tax amount in the total installed cost, the sales tax influences the debt amount and debt interest payment. For projects where debt interest payments are deductible from federal and state income tax (all financing options except Residential with standard loan), SAM includes sales tax in the calculation of the deductions.

Insurance Rate (Annual)

The annual insurance rate applies to the total installed cost of the project. SAM treats insurance as an operating cost for each year. The insurance cost in year one of the project cash flow is the insurance rate multiplied by the total installed cost from the System Costs page. The first year cost is then increased by inflation in each subsequent year. For commercial and utility projects, the insurance cost is an operating expense and therefore reduces federal and state taxable income.

Property Tax

Property tax is an annual project expense that SAM includes under Operating Expenses in the cash flow.

SAM treats property tax as a tax-deductible operating expense for each year. In each year of the project cash flow, the property tax cost is the property tax rate multiplied by the assessed value for that year.

SAM determines the annual property tax payment by calculating an assessed value for each year in the cash flow, and applying the assessed percent to that value. The assessed value may decline from year to year at the rate you specify. The assessed percent and tax rate both remain constant from year to year.

For residential projects, the property tax amount is the only operating cost that can be deducted from state and federal income tax.

> **Note.** For the residential and commercial financing option, SAM calculates a real estate value added amount for each year in the analysis period. SAM does not use the value to calculate property tax, or to calculate financial metrics such as LCOE or NPV. You can find the value on the Results page Tables under **Annual Data**.

Assessed Percent

The assessed value of property subject to property taxes as a percentage of the system total installed cost specified on the System Costs page. SAM uses this value to calculate the assessed property value in year one of the project cash flow.

Assessed Value

The assessed property value in Year One of the project cash flow:

Assessed Value ($) = Assessed Percent (%) × Total Installed Cost ($)

Where Total Installed Cost is from the System Costs page.

Assessed Value Decline

The annual decline in the assessed property value. SAM uses this value to calculate the property assessed value in years two and later of the project cash flow. For an assessed value that does not decrease annually, specify a value of zero percent per year.

Property Tax

The annual property tax rate applies to the assessed value of the project in each year of the project cash flow.

Salvage Value

SAM considers the salvage value to be project income in the final year of the project cash flow, and calculates the value as a percentage of the total installed cost from the System Costs page.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period. SAM reports the salvage value amount in the final year of the project cash flow under Operating Expenses.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

For residential projects, the salvage value has no effect on federal and state income tax.

For commercial and utility projects, the salvage value is treated as a source of pre-tax revenue in the final year of the analysis period, increasing the federal and state taxable income.

Net Salvage Value

The salvage value as a percentage of the project's total installed cost from the System Costs page.

End of Analysis Period Salvage Value

The salvage value dollar amount that will appear in final year of the project cash flow.

End of Analysis Period Salvage Value ($) = Net Salvage Value (%) × Total Installed Cost ($)

Where *Total Installed Cost* is from the System Costs page.

13.4 Commercial

This topic describes the inputs on the Financing page for the Commercial financing option. For a general description of financial structures SAM can model, see Financing Overview.

SAM displays results of the financial model in the cash flow. See Cash Flow Variables for details.

Commercial Loan Parameters

Note. For the residential mortgage and commercial financing options, SAM deducts loan interest payments from state and federal income taxes. For the residential loan option, SAM does not deduct loan interest payments. For details see, the project cash flow on the Results page.

Debt Fraction

Percentage of the total installed cost to be borrowed.

For example, specifying a debt fraction of 25% means that the project borrows 25% of the total installed cost amount shown on the system costs page for a 25/75 debt-equity ratio.

Loan Term

Number of years required to repay a loan. Note that this value is different than the analysis period.

Loan Rate

Annual loan interest rate.

Principal Amount

The loan principal amount, or amount borrowed.

This is a calculated value that you cannot directly edit. To change the value, change either the value of the debt fraction or a cost on the System Costs page.

Principal Amount ($) = Total Installed Cost ($) × Debt Fraction (%)

Where *Total Installed Cost* is from the System Costs page.

WACC

The Weighted Average Cost of Capital (WACC) is defined as the minimum return that the project must earn to cover financing costs.

SAM displays the WACC for reference. It is not used in any calculations.

This is calculated value that you cannot directly edit. To change its value, change one of the parameters described in the following equation:

WACC = Real Discount Rate × (1 - Debt Fraction) + (1 - Effective Tax Rate) × Loan Rate × Debt Fraction

The effective tax rate is a single number that includes both the federal income tax rate and state income tax rate. SAM uses the effective tax rate for several calculations requiring a total income tax value:

Effective Tax Rate = Federal Tax Rate × (1 - State Tax Rate) + State Tax Rate

Analysis Parameters

The analysis parameters specify the analysis period, inflation rate and discount rate.

Analysis Period

Number of years covered by the analysis. Typically equivalent to the project or investment life. The analysis period determines the number of years in the project cash flow.

Inflation Rate

Annual rate of change of costs, typically based on a price index. SAM uses the inflation rate to calculate the value of costs in years two and later of the project cash flow based on Year One dollar values that you specify on the System Costs page, Financing page, Utility Rate page, Incentives, or pages.

The default value of 2.5% is based on consumer price index data from the U.S. Department of Labor Bureau of Labor Statistics, and is the average of the annual average consumer price index between 1991 and 2012.

Real Discount Rate

A measure of the time value of money expressed as an annual rate. SAM uses the real discount rate to calculate the present value (value in year one) of dollar amounts in the project cash flow over the analysis period and to calculate annualized costs.

> **Note.** For projects with one of the Utility or Commercial PPA financing options, SAM includes both a discount rate and internal rate of return (IRR) in the analysis. For these projects, the discount rate represents the value of an alternative investment, and the IRR can represent a profit requirement or the risk associated with the project. For example, the IRR may be higher than the discount rate for a renewable energy project with higher risk than an alternative investment.

Nominal Discount Rate

SAM calculates the nominal discount based on the values of the real discount rate and the inflation rate:

Nominal Discount Rate = (1 + Real Discount Rate) × (1 + Inflation Rate) - 1

Tax and Insurance Rates

Federal and State Income Tax Rates

The annual federal and state income tax rate applies to taxable income and is used to calculate tax benefits or liabilities.

For all projects, taxable income includes income from any incentives marked on the Incentives page as taxable.

For residential and commercial projects, SAM does not consider the value of electricity saved by the system to be income. However, for commercial projects, because those savings represent the value of electricity purchases that would have been a tax-deductible operating expense to the commercial entity, SAM does reduce the project after-tax cash flow by the amount of federal and state income tax on the value of the electricity. In other words, with the renewable energy system in place, the commercial entity must pay tax on that portion of its income that it would have deducted as an operating expense.

For commercial PPA and utility IPP projects, the energy value represents electricity sales that are taxable income.

Sales Tax

The sales tax is a one-time tax that SAM includes in the project's total installed cost. SAM calculates the sales tax amount by multiplying the sales tax rate on the Financing page by the rate you specify under Indirect Capital Costs and the Total Direct Cost on the System Costs page.

For tax purposes, because SAM includes the sales tax amount in the total installed cost, it treats sales tax as part of the cost of property. For projects with depreciation (Commercial and Utility financing options only), SAM includes the sales tax amount in the depreciable basis. See IRS Publication 551, Basis of Assets, for more details.

Some states and other jurisdictions offer a sales tax exemption for renewable energy projects. To model a sales tax exemption in SAM, reduce the sales tax percentage as appropriate. For example, for a 100% sales tax exemption, enter a sales tax rate of zero.

For projects with debt, because SAM includes the sales tax amount in the total installed cost, the sales tax influences the debt amount and debt interest payment. For projects where debt interest payments are deductible from federal and state income tax (all financing options except Residential with standard loan), SAM includes sales tax in the calculation of the deductions.

Insurance Rate (Annual)

The annual insurance rate applies to the total installed cost of the project. SAM treats insurance as an operating cost for each year. The insurance cost in year one of the project cash flow is the insurance rate multiplied by the total installed cost from the System Costs page. The first year cost is then increased by inflation in each subsequent year. For commercial and utility projects, the insurance cost is an operating expense and therefore reduces federal and state taxable income.

Property Tax

Property tax is an annual project expense that SAM includes under Operating Expenses in the cash flow.

SAM treats property tax as a tax-deductible operating expense for each year. In each year of the project cash flow, the property tax cost is the property tax rate multiplied by the assessed value for that year.

SAM determines the annual property tax payment by calculating an assessed value for each year in the cash flow, and applying the assessed percent to that value. The assessed value may decline from year to year at the rate you specify. The assessed percent and tax rate both remain constant from year to year.

For residential projects, the property tax amount is the only operating cost that can be deducted from state and federal income tax.

Note. For the residential and commercial financing option, SAM calculates a real estate value added amount for each year in the analysis period. SAM does not use the value to calculate property tax, or to calculate financial metrics such as LCOE or NPV. You can find the value on the Results page Tables under **Annual Data**.

Assessed Percent

The assessed value of property subject to property taxes as a percentage of the system total installed cost specified on the System Costs page. SAM uses this value to calculate the assessed property value in year one of the project cash flow.

Assessed Value

The assessed property value in Year One of the project cash flow:

Assessed Value ($) = Assessed Percent (%) × Total Installed Cost ($)

Where Total Installed Cost is from the System Costs page.

Assessed Value Decline

The annual decline in the assessed property value. SAM uses this value to calculate the property assessed value in years two and later of the project cash flow. For an assessed value that does not decrease annually, specify a value of zero percent per year.

Property Tax

The annual property tax rate applies to the assessed value of the project in each year of the project cash flow.

Salvage Value

SAM considers the salvage value to be project income in the final year of the project cash flow, and calculates the value as a percentage of the total installed cost from the System Costs page.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period. SAM reports the salvage value amount in the final year of the project cash flow under Operating Expenses.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

For residential projects, the salvage value has no effect on federal and state income tax.

For commercial and utility projects, the salvage value is treated as a source of pre-tax revenue in the final year of the analysis period, increasing the federal and state taxable income.

Net Salvage Value

The salvage value as a percentage of the project's total installed cost from the System Costs page.

End of Analysis Period Salvage Value

The salvage value dollar amount that will appear in final year of the project cash flow.

End of Analysis Period Salvage Value ($) = Net Salvage Value (%) × Total Installed Cost ($)

Where *Total Installed Cost* is from the System Costs page.

13.5 Utility IPP and Commercial PPA

This topic describes the inputs on the Financing page for the Utility IPP and Commercial PPA financing options. For a general description of financial structures SAM can model, see Financing Overview.

SAM displays results of the financial model in the cash flow. See Cash Flow Variables for details.

Solution Mode

SAM offers two solution modes for the Commercial PPA and Independent Power Producer financing options:

- Specify IRR Target allows you to specify the internal rate of return (IRR) as an input, and SAM uses a search algorithm to find the PPA price required to meet the target IRR.
- Specify PPA Price allows you to specify the PPA price as an input, and SAM calculates the resulting IRR.

Solution Mode 1: Specify IRR Target

The Specify IRR Target option allows you to specify a desired target IRR. SAM finds the PPA price required to meet the target given the financing assumptions and system costs you specify.

SAM uses an iterative algorithm to search for the PPA price that meets the target IRR. If it cannot find a solution, it finds the PPA price that results in an IRR as close as possible to the target value, and reports the IRR in results as an "actual" value.

> **Notes.**
>
> In some cases, the actual IRR may differ significantly from the target IRR. If you are not satisfied with the actual values, you can adjust your assumptions and rerun simulations until the actual and target values match.
>
> If your analysis involves time-of-delivery (TOD) factors, see the Notes under the PPA Price description below (Under the Solution Mode 2 description).

After running simulations, SAM shows both the target values and the actual values in the Metrics table.

Minimum Required IRR

The project's minimum internal rate of return target.

PPA Escalation Rate

An escalation rate applied to the PPA price in Year One of the cash flow to calculate the electricity sales price in Years two and later. When the financial optimization option is checked, the PPA escalation rate is a result instead of an input variable.

> **Note.** SAM does not apply the inflation rate to the PPA price.

Constraint: Require a Minimum DSCR

A requirement that the debt-service coverage ratio not be allowed to fall below the specified level.

Minimum Required DSCR

The lowest value of the DSCR required for the project to be financially feasible. The DSCR is the ratio of operating income to costs in a given year.

Constraint: Require a positive cash flow

A requirement that the annual project cash flow be positive throughout the project life.

The financial optimization options allow you to automatically optimize the debt fraction and PPA escalation rate to minimize the levelized cost of energy. When you optimize the value of these variables, SAM finds the debt fraction and PPA escalation rates that result in the lowest levelized cost of energy. This optimization is often necessary to minimize project costs when you specify constraints on the internal rate of return (IRR), debt-service coverage ratio (DSCR), and positive cash flow (See Wiser 1996 in References).

Allow SAM to pick a debt fraction to minimize the LCOE

Check this option instead of entering a value for Debt Fraction to allow SAM to find the debt fraction value that results in the lowest levelized cost of energy. When you check this option, SAM disables the debt fraction input variable and reports it as a result in the Metrics table on the Results page.

Allow SAM to pick a PPA escalation rate to minimize the LCOE

Check this option instead of entering a value PPA Escalation Rate to allow SAM to find the PPA escalation rate value that results in the lowest levelized cost of energy. When you check this option, SAM disables the PPA escalation rate input variable and reports it as a result in the Metrics table on the Results page.

Solution Mode 2: Specify PPA Price

Choose this option when you want SAM to calculate the IRR based on a power purchase bid price that you specify.

After simulations, SAM shows the project IRR that it calculated in the Metrics table, along with the PPA price you specify.

PPA Price

The power purchase bid price in dollars per kilowatt-hour.

> **Notes.**
>
> For most analyses, the PPA price is equal to the price in Year One of the cash flow. The price in Years two and later is the PPA price adjusted by the optional escalation rate.
>
> If your analysis involves TOD factors, the Year One price is the PPA price that you specify on the Financing page adjusted by the time-of-delivery (TOD) factors and schedule that you specify either on the Time of Delivery Factors page, or for CSP systems, on the Thermal Energy Storage page.

PPA Escalation Rate

An optional annual power price escalation rate.

> **Note.** SAM does not apply the inflation rate to the PPA price.

Loan Parameters

Debt Fraction

Percentage of the total installed cost to be borrowed.

For example, specifying a debt fraction of 25% means that the project borrows 25% of the Total Installed Cost amount shown on the system costs page for a 25/75 debt-equity ratio.

> **Note.** For projects with Independent Power Producer or Commercial PPA financing, if you check **Allow SAM to pick a debt fraction to minimize the LCOE** under **Specify IRR Target**, SAM disables the Debt Fraction input variable.

Loan Term

Number of years required to repay a loan. Note that this value is different than the analysis period.

Loan Rate

Annual loan interest rate.

Installed Cost

The Total Installed Cost from the System Costs page.

Construction Financing Cost

The Total Construction Financing Cost that you specify under **Construction Period**.

Principal Amount

The loan principal amount.

This is a calculated value and cannot be edited. To change the value, either change the value of the debt fraction, or change the value of cost variables on the System Costs page.

Principal Amount ($) = (Total Installed Cost ($) + Construction Financing Cost ($)) × Debt Fraction (%)

Note. The Principal Amount is different from the Debt Balance in Year One reported in the Cash Flow when your analysis includes either investment-based or capacity-based incentives: The principal amount does not account for incentives because the total incentive amounts are not available until after you run simulations.

WACC

The Weighted Average Cost of Capital (WACC) is an estimated value representing the weighted average cost of the project's after-tax equity and debt capital. SAM calculates the WACC using the minimum required IRR value that you specify under **Specify IRR Target**.

SAM displays the WACC for reference and does not use it for calculations. It is based on the target IRR you specify as an input, not the actual IRR that SAM calculates as a result from the project cash flows.

The WACC is a calculated value that you cannot directly edit. To change its value, change one of the parameters described in the following equations:

WACC = Minimum Required IRR × (1 - Debt Fraction) + (1 - Effective Tax Rate) × Loan Rate × Debt Fraction

Where *Minimum Required IRR* is the value you choose under Specify IRR Target. (If you choose the **Specify PPA Price** solution mode option, SAM uses the **Minimum Required IRR** value visible in the inactive variable for the WACC calculation.) *Effective Tax Rate* is a single number that includes both the federal income tax rate and state income tax rate:

Effective Tax Rate = Federal Tax Rate × (1 - State Tax Rate) + State Tax Rate

A Note about WACC and IRR. The WACC is a value that represents the project's after-tax cost of equity and debt, and can be calculated before you know the project cash flows. The IRR is the discount rate that results a net present value of zero for after-tax project cash flows. SAM shows you the WACC on the Financing page for reference, as a value that assumes that the IRR target you specify can be met. SAM calculates the actual IRR during simulations, and displays it in the Metrics table on the Results page.

Analysis Parameters

The analysis parameters specify the analysis period, inflation rate and discount rate.

Analysis Period

Number of years covered by the analysis. Typically equivalent to the project or investment life. The analysis period determines the number of years in the project cash flow.

Inflation Rate

Annual rate of change of costs, typically based on a price index. SAM uses the inflation rate to calculate the value of costs in years two and later of the project cash flow based on Year One dollar values that you specify on the System Costs page, Financing page, Utility Rate page, Incentives, or pages.

The default value of 2.5% is based on consumer price index data from the U.S. Department of Labor Bureau of Labor Statistics, and is the average of the annual average consumer price index between 1991 and 2012.

Real Discount Rate

A measure of the time value of money expressed as an annual rate. SAM uses the real discount rate to calculate the present value (value in year one) of dollar amounts in the project cash flow over the analysis period and to calculate annualized costs.

Note. For projects with one of the Utility or Commercial PPA financing options, SAM includes both a discount rate and internal rate of return (IRR) in the analysis. For these projects, the discount rate represents the value of an alternative investment, and the IRR can represent a profit requirement or the risk associated with the project. For example, the IRR may be higher than the discount rate for a renewable energy project with higher risk than an alternative investment.

Nominal Discount Rate

SAM calculates the nominal discount based on the values of the real discount rate and the inflation rate:

Nominal Discount Rate = (1 + Real Discount Rate) × (1 + Inflation Rate) - 1

Tax and Insurance Rates

Federal and State Income Tax Rates

The annual federal and state income tax rate applies to taxable income and is used to calculate tax benefits or liabilities.

For all projects, taxable income includes income from any incentives marked on the Incentives page as taxable.

For residential and commercial projects, SAM does not consider the value of electricity saved by the system to be income. However, for commercial projects, because those savings represent the value of electricity purchases that would have been a tax-deductible operating expense to the commercial entity, SAM does reduce the project after-tax cash flow by the amount of federal and state income tax on the value of the electricity. In other words, with the renewable energy system in place, the commercial entity must pay tax on that portion of its income that it would have deducted as an operating expense.

For commercial PPA and utility IPP projects, the energy value represents electricity sales that are taxable income.

Sales Tax

The sales tax is a one-time tax that SAM includes in the project's total installed cost. SAM calculates the sales tax amount by multiplying the sales tax rate on the Financing page by the rate you specify under Indirect Capital Costs and the Total Direct Cost on the System Costs page.

For tax purposes, because SAM includes the sales tax amount in the total installed cost, it treats sales tax as part of the cost of property. For projects with depreciation (Commercial and Utility financing options only), SAM includes the sales tax amount in the depreciable basis. See IRS Publication 551, Basis of Assets, for more details.

Some states and other jurisdictions offer a sales tax exemption for renewable energy projects. To model a sales tax exemption in SAM, reduce the sales tax percentage as appropriate. For example, for a 100% sales tax exemption, enter a sales tax rate of zero.

For projects with debt, because SAM includes the sales tax amount in the total installed cost, the sales tax influences the debt amount and debt interest payment. For projects where debt interest payments are deductible from federal and state income tax (all financing options except Residential with standard loan), SAM includes sales tax in the calculation of the deductions.

Insurance Rate (Annual)

The annual insurance rate applies to the total installed cost of the project. SAM treats insurance as an operating cost for each year. The insurance cost in year one of the project cash flow is the insurance rate multiplied by the total installed cost from the System Costs page. The first year cost is then increased by inflation in each subsequent year. For commercial and utility projects, the insurance cost is an operating expense and therefore reduces federal and state taxable income.

Property Tax

Property tax is an annual project expense that SAM includes under Operating Expenses in the cash flow.

SAM treats property tax as a tax-deductible operating expense for each year. In each year of the project cash flow, the property tax cost is the property tax rate multiplied by the assessed value for that year.

SAM determines the annual property tax payment by calculating an assessed value for each year in the cash flow, and applying the assessed percent to that value. The assessed value may decline from year to year at the rate you specify. The assessed percent and tax rate both remain constant from year to year.

For residential projects, the property tax amount is the only operating cost that can be deducted from state and federal income tax.

Note. For the residential and commercial financing option, SAM calculates a real estate value added amount for each year in the analysis period. SAM does not use the value to calculate property tax, or to calculate financial metrics such as LCOE or NPV. You can find the value on the Results page Tables under **Annual Data**.

Assessed Percent

The assessed value of property subject to property taxes as a percentage of the system total installed cost specified on the System Costs page. SAM uses this value to calculate the assessed property value in year one of the project cash flow.

Assessed Value

The assessed property value in Year One of the project cash flow:

Assessed Value ($) = Assessed Percent (%) × Total Installed Cost ($)

Where Total Installed Cost is from the System Costs page.

Assessed Value Decline

The annual decline in the assessed property value. SAM uses this value to calculate the property assessed value in years two and later of the project cash flow. For an assessed value that does not decrease annually, specify a value of zero percent per year.

Property Tax

The annual property tax rate applies to the assessed value of the project in each year of the project cash flow.

Salvage Value

SAM considers the salvage value to be project income in the final year of the project cash flow, and calculates the value as a percentage of the total installed cost from the System Costs page.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period. SAM reports the salvage value amount in the final year of the project cash flow under

Operating Expenses.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

For residential projects, the salvage value has no effect on federal and state income tax.

For commercial and utility projects, the salvage value is treated as a source of pre-tax revenue in the final year of the analysis period, increasing the federal and state taxable income.

Net Salvage Value

The salvage value as a percentage of the project's total installed cost from the System Costs page.

End of Analysis Period Salvage Value

The salvage value dollar amount that will appear in final year of the project cash flow.

End of Analysis Period Salvage Value ($) = Net Salvage Value (%) × Total Installed Cost ($)

Where *Total Installed Cost* is from the System Costs page.

Construction Financing

SAM allows you to specify parameters for up to five construction loans to approximate interest during construction (IDC) that SAM considers to be a cost to the project.

SAM assumes that 100% of the construction balance is outstanding for half of the construction period, which is equivalent to an even monthly draw schedule with an average loan life of half of the construction period. To approximate a different draw schedule, you could adjust the loan's interest rate accordingly.

Note. To model a project with no construction period loans, set the **Percent of Installed Costs** value for each of the five loans to zero.

For the Commercial PPA and Independent Power Producer options, SAM includes the total construction financing cost in the project loan principal amount shown on the Financing page.

For the partnership flip, sale leaseback, and single owner options, SAM includes the total construction financing cost in the Financing Cost reported in the Metrics table. The financing cost, in turn, is part of issuance of equity value reported in the project cash flow.

Construction Loans

SAM allows you to specify up to five construction loans. You can type a name describing each loan or use the default names.

Percent of Installed Costs

The amount borrowed for the construction loan as a percentage of the total installed cost, assuming that all construction costs are included in the installation costs you specify on the System Costs page. Specify a non-zero percentage for each construction period loan you want to include in the analysis.

The sum of the up to five percentage values you specify for each construction loan must be 100%.

Up-front Fee

A percentage of the principal amount, typically between 1% and 3% that SAM adds to the interest amount for each construction loan to calculate the total construction financing cost. Note that no interest applies to the up-front fee.

Up-front Fee Amount ($) = Principal Amount ($) × Up-front Fee Percentage (%)

Months Prior to Operation

The loan period for the construction loan in months.

Annual Interest Rate

The construction loan interest rate as an annual percentage.

Principal

The amount borrowed for each construction period loan:

Principal Amount ($) = Total Installed Cost ($) × Percent of Installed Costs (%)

Interest

The total interest payment due for each construction period loan, assuming that 100% of the construction balance is outstanding for half of the construction period.

Interest ($) = Principal Amount ($) × Loan Rate (%/yr) / 12 (mos/yr) × 0.5

Total Construction Financing Cost

SAM includes the total construction financing cost in the project cost.

Total Construction Financing Cost = Interest + Up-front Fee Amount

13.6 Utility Single Owner

This topic describes the inputs on the Financing page for the Utility Single Owner financing option. For a general description of financial structures SAM can model, see Financing Overview.

SAM displays results of the financial model in the cash flow. See Cash Flow Variables for details.

Solution Mode

The solution mode determines whether SAM calculates a PPA price based on IRR targets that you specify, or an IRR based on a PPA price that you specify.

- Specify IRR Target allows you to specify the IRR as an input, and SAM uses a search algorithm to find the PPA price required to meet the target IRR.
- Specify PPA Price allows you to specify the PPA price as an input, and SAM calculates the resulting IRR.

Solution Mode 1: Specify IRR Target

The Specify IRR Target option allows you to specify a desired IRR target and the year you would like the IRR to be achieved. SAM finds the PPA price required to meet the target given the financing assumptions and system costs you specify. For the partnership financing options that involve a tax investor and developer, you specify the target IRR from the tax investor's perspective.

SAM uses an iterative algorithm to search for the PPA price that meets the IRR target in the year you specify. If it cannot find a solution, it finds the PPA price that results in an IRR and year as close as possible to the target values, and reports the IRR and year in results as "actual" values.

Notes.

In some cases, the actual values may differ significantly from the target values. If you are not satisfied with the actual values, you can adjust your assumptions and rerun simulations until the actual and target values match.

If your analysis involves time-of-delivery (TOD) factors, see the notes under the Solution Mode 2 description below.

After running simulations, SAM shows both the target values and the actual values in the Metrics table. For the partnership financing options that involve a tax investor and developer, SAM shows the IRR for both partners.

IRR Target

The desired IRR target as a percentage:

- For the Single Owner option the required IRR is the project IRR.
- For the All Equity and Leveraged Partnership Flip options and Sale Leaseback option, the target IRR is the tax investor IRR. SAM calculates the developer IRR as a function of the value in excess of the tax investor IRR.

Tip. SAM assumes a default tax equity return rate of 8.5% for the All Equity Partnership Flip option and a default rate of 10.5% for the Leveraged Partnership Flip option. In practice, tax investors may accept lower or require higher returns for specific projects than these rates, depending on project size, market conditions, and perceived project risks.The solution mode determines whether SAM calculates a PPA price based on an IRR that you specify or whether SAM calculates IRR values based on a PPA price that you specify.

Target Year

The year in which the target IRR will be achieved. For the partnership flip options, this is the flip year when project returns switch from the tax investor (pre-flip) to the developer (post-flip).

Solution Mode 2: Specify PPA Price

The Specify PPA Price option allows you to specify a power purchase bid price:

- For the Single Owner option, SAM calculates the project IRR.
- For All Equity and Leveraged Partnership Flip options, and Sale Leaseback option that involve two parties, SAM calculates two IRR values: One from the tax investor perspective, and one from the developer perspective. For the partnership flip options, SAM also calculates the flip year when project returns switch from the tax investor to the developer.

After running simulations, SAM shows the IRR values in the Metrics table and cash flow.

Note. For the Specify PPA Price option, the IRR target year, IRR target, IRR actual year, and IRR in target years shown in the Metrics table are not valid results because these values do not apply to the option.

PPA Price

The power price in cents per kWh. This is the price that would be negotiated as part of a power purchase agreement.

Escalation Rate

An escalation rate applied to the PPA price in Year One to calculate the electricity sales price in years two and later in the project cash flow.

SAM does not apply the inflation rate to the PPA price. If you do not specify a PPA price escalation rate, SAM assumes that the same price applies in all years of the analysis period.

Notes.

For most analyses, the PPA price is equal to the PPA price in Year One of the cash flow. The price in Years two and later is the PPA price adjusted by the optional escalation rate.

If your analysis involves TOD factors, the Year One PPA price is the PPA price that you specify on the Financing page adjusted by the time-of-delivery (TOD) factors and schedule that you specify either on the Time of Delivery Factors page, or for concentrating solar power (CSP) systems, on the Thermal Energy Storage page.

Analysis Parameters

The analysis parameters specify the analysis period, inflation rate and discount rate.

Analysis Period

Number of years covered by the analysis. Typically equivalent to the project or investment life. The analysis period determines the number of years in the project cash flow.

Inflation Rate

Annual rate of change of costs, typically based on a price index. SAM uses the inflation rate to calculate the value of costs in years two and later of the project cash flow based on Year One dollar values that you specify on the System Costs page, Financing page, Utility Rate page, Incentives, or pages.

The default value of 2.5% is based on consumer price index data from the U.S. Department of Labor Bureau of Labor Statistics, and is the average of the annual average consumer price index between 1991 and 2012.

Real Discount Rate

A measure of the time value of money expressed as an annual rate. SAM uses the real discount rate to calculate the present value (value in year one) of dollar amounts in the project cash flow over the analysis period and to calculate annualized costs.

Note. For projects with one of the Utility or Commercial PPA financing options, SAM includes both a discount rate and internal rate of return (IRR) in the analysis. For these projects, the discount rate represents the value of an alternative investment, and the IRR can represent a profit requirement or the risk associated with the project. For example, the IRR may be higher than the discount rate for a renewable energy project with higher risk than an alternative investment.

Nominal Discount Rate

SAM calculates the nominal discount based on the values of the real discount rate and the inflation rate:

Nominal Discount Rate = (1 + Real Discount Rate) × (1 + Inflation Rate) - 1

Taxes and Insurance Rates

Federal and State Income Tax Rates

The annual federal and state income tax rate applies to taxable income and is used to calculate tax benefits or liabilities.

For all projects, taxable income includes income from any incentives marked on the Incentives page as taxable.

For residential and commercial projects, SAM does not consider the value of electricity saved by the system to be income. However, for commercial projects, because those savings represent the value of electricity purchases that would have been a tax-deductible operating expense to the commercial entity, SAM does reduce the project after-tax cash flow by the amount of federal and state income tax on the value of the electricity. In other words, with the renewable energy system in place, the commercial entity must pay tax on that portion of its income that it would have deducted as an operating expense.

For commercial PPA and utility IPP projects, the energy value represents electricity sales that are taxable income.

Sales Tax

The sales tax is a one-time tax that SAM includes in the project's total installed cost. SAM calculates the sales tax amount by multiplying the sales tax rate on the Financing page by the rate you specify under Indirect Capital Costs and the Total Direct Cost on the System Costs page.

For tax purposes, because SAM includes the sales tax amount in the total installed cost, it treats sales tax as part of the cost of property. For projects with depreciation (Commercial and Utility financing options only), SAM includes the sales tax amount in the depreciable basis. See IRS Publication 551, Basis of Assets, for more details.

Some states and other jurisdictions offer a sales tax exemption for renewable energy projects. To model a sales tax exemption in SAM, reduce the sales tax percentage as appropriate. For example, for a 100% sales tax exemption, enter a sales tax rate of zero.

For projects with debt, because SAM includes the sales tax amount in the total installed cost, the sales tax influences the debt amount and debt interest payment. For projects where debt interest payments are deductible from federal and state income tax (all financing options except Residential with standard loan), SAM includes sales tax in the calculation of the deductions.

Insurance Rate (Annual)

The annual insurance rate applies to the total installed cost of the project. SAM treats insurance as an operating cost for each year. The insurance cost in year one of the project cash flow is the insurance rate multiplied by the total installed cost from the System Costs page. The first year cost is then increased by inflation in each subsequent year. For commercial and utility projects, the insurance cost is an operating expense and therefore reduces federal and state taxable income.

Property Tax

Property tax is an annual project expense that SAM includes under Operating Expenses in the cash flow.

SAM treats property tax as a tax-deductible operating expense for each year. In each year of the project cash flow, the property tax cost is the property tax rate multiplied by the assessed value for that year.

SAM determines the annual property tax payment by calculating an assessed value for each year in the cash flow, and applying the assessed percent to that value. The assessed value may decline from year to year at the rate you specify. The assessed percent and tax rate both remain constant from year to year.

For residential projects, the property tax amount is the only operating cost that can be deducted from state and federal income tax.

> **Note.** For the residential and commercial financing option, SAM calculates a real estate value added amount for each year in the analysis period. SAM does not use the value to calculate property tax, or to calculate financial metrics such as LCOE or NPV. You can find the value on the Results page Tables under **Annual Data**.

Assessed Percent

The assessed value of property subject to property taxes as a percentage of the system total installed cost specified on the System Costs page. SAM uses this value to calculate the assessed property value in year one of the project cash flow.

Assessed Value

The assessed property value in Year One of the project cash flow:

Assessed Value ($) = Assessed Percent (%) × Total Installed Cost ($)

Where Total Installed Cost is from the System Costs page.

Assessed Value Decline

The annual decline in the assessed property value. SAM uses this value to calculate the property assessed value in years two and later of the project cash flow. For an assessed value that does not decrease annually, specify a value of zero percent per year.

Property Tax

The annual property tax rate applies to the assessed value of the project in each year of the project cash flow.

Salvage Value

SAM considers the salvage value to be project income in the final year of the project cash flow, and calculates the value as a percentage of the total installed cost from the System Costs page.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period. SAM reports the salvage value amount in the final year of the project cash flow under Operating Expenses.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

For residential projects, the salvage value has no effect on federal and state income tax.

For commercial and utility projects, the salvage value is treated as a source of pre-tax revenue in the final year of the analysis period, increasing the federal and state taxable income.

Net Salvage Value

The salvage value as a percentage of the project's total installed cost from the System Costs page.

End of Analysis Period Salvage Value

The salvage value dollar amount that will appear in final year of the project cash flow.

End of Analysis Period Salvage Value ($) = Net Salvage Value (%) × Total Installed Cost ($)

Where *Total Installed Cost* is from the System Costs page.

Construction Financing

SAM allows you to specify parameters for up to five construction loans to approximate interest during construction (IDC) that SAM considers to be a cost to the project.

SAM assumes that 100% of the construction balance is outstanding for half of the construction period, which is equivalent to an even monthly draw schedule with an average loan life of half of the construction period. To approximate a different draw schedule, you could adjust the loan's interest rate accordingly.

> **Note.** To model a project with no construction period loans, set the **Percent of Installed Costs** value for each of the five loans to zero.

For the Commercial PPA and Independent Power Producer options, SAM includes the total construction financing cost in the project loan principal amount shown on the Financing page.

For the partnership flip, sale leaseback, and single owner options, SAM includes the total construction financing cost in the Financing Cost reported in the Metrics table. The financing cost, in turn, is part of issuance of equity value reported in the project cash flow.

Construction Loans

SAM allows you to specify up to five construction loans. You can type a name describing each loan or use the default names.

Percent of Installed Costs

The amount borrowed for the construction loan as a percentage of the total installed cost, assuming that all construction costs are included in the installation costs you specify on the System Costs page. Specify a non-zero percentage for each construction period loan you want to include in the analysis.

The sum of the up to five percentage values you specify for each construction loan must be 100%.

Up-front Fee

A percentage of the principal amount, typically between 1% and 3% that SAM adds to the interest amount for each construction loan to calculate the total construction financing cost. Note that no interest applies to the up-front fee.

Up-front Fee Amount ($) = Principal Amount ($) × Up-front Fee Percentage (%)

Months Prior to Operation

The loan period for the construction loan in months.

Annual Interest Rate

The construction loan interest rate as an annual percentage.

Principal

The amount borrowed for each construction period loan:

Principal Amount ($) = Total Installed Cost ($) × Percent of Installed Costs (%)

Interest

The total interest payment due for each construction period loan, assuming that 100% of the construction balance is outstanding for half of the construction period.

Interest ($) = Principal Amount ($) × Loan Rate (%/yr) / 12 (mos/yr) × 0.5

Total Construction Financing Cost

SAM includes the total construction financing cost in the project cost.

Total Construction Financing Cost = Interest + Up-front Fee Amount

Project Term Debt

The Project Term Debt input variables determine the quantity and cost of debt. SAM calculates the debt fraction as a result based on the debt terms you specify here.

Debt Service Coverage Ratio (DSCR)

The ratio of annual cash available for debt service to the sum of the annual principal and interest payment.

Annual cash available for debt service is equal to the Earnings Before Interest Taxes Depreciation and Amortization (EBITDA) value shown in the cash flow less cash used to fund the major equipment replacement reserves.

SAM assumes that the debt service coverage ratio remains constant over the analysis period. To model a project with a debt-service ratio that varies from year to year, use the utility IPP financing option, which allows you to specify a minimum debt-service coverage ratio.

Tip. The DSCR generally ranges between 1.40 and 1.50 for proven wind technology. For solar, the ratios are slightly lower: In the 1.30 to 1.40 range for PV, and perhaps slightly lower for CSP and CPV technologies.

Tenor

The loan period in years.

Annual All-In Interest Rate

Annual loan interest rate.

Debt Closing Costs

A dollar amount representing debt closing costs.

Up-Front Fee

A percentage of the total debt representing debt closing costs.

Note. SAM considers debt closing costs and up-front fee to be part of the project's Financing Cost reported in the Metrics table, which is part of the issuance of equity value reported in the cash flow.

Production Based Incentives (PBI) Available for Debt Service

If you specified one or more production-based incentives on the Incentives page, and the incentives can be used to service debt, check the box for the incentive.

For example, if you specified a Utility PBI on the Cash Incentives page that can be used to service debt, check the Utility box.

When you check the option for a PBI, SAM includes the PBI amount in the total revenue amount that is used to calculate the DSCR, and is reported in the project cash flow.

Cost of Acquiring Financing

The Cost of Acquiring Financing input values represent the cost of securing debt or the participation of tax investors.

Financing Cost (Single Owner only)

The dollar amount associated with acquiring financing.

Development Fee (All options except Single Owner)

A fee paid to the developer in Year 0, specified as a percentage of the total installed cost on the System Costs page.

Development Fee ($) = Development Fee (%) × Total Installed Cost ($)

Equity Closing Cost (All options except Single Owner)

A dollar amount representing costs associated with securing participation of a tax investor, such as consultants and legal fees.

Other Financing Costs (All options except Single Owner)

A dollar amount for financing costs not included in the equity closing cost or development fee.

SAM calculates the project's total cost of financing and reports it as the Financing Cost in the Metrics table, which is part of the issuance of equity value reported in the cash flow.

Reserve Accounts

Interest on Reserves

Annual interest rate earned on funds in reserve accounts. The different financing options have different reserve accounts, and the interest on reserves rate applies to all of the accounts available for a given option:

- Working capital reserve account, specified under Cost of Acquiring Financing.
- Major equipment reserve account, specified under Major Equipment Replacement Reserves.
- Debt service reserve account (Leveraged Partnership Flip, Single Owner), specified under Debt Service.
- Lessee reserve account (Sale Leaseback), specified under Sale Leaseback.

Working Capital Reserve Account

The size of the working capital reserve in months of operation.

Working Capital Reserve Amount = Months of Operating Costs (months) / 12 months/yr × Year One Total Expenses ($/yr)

Debt Service Reserve Account

A debt service reserve account is a fund that may be required by the project debt provider. The account is funded in Year 0 and earns interest in Years 1 and later at the reserve interest rate specified under Reserves. Once debt has been repaid, the funds in the account are released to the project cash flow.

The number of months of principal and interest payments in Year One whose value is equivalent to the size of the debt reserve account in Year 0.

SAM calculates the reserve account size in Year 0 based on the principal and interest amounts in Year

One:

Year 0 Debt Service Reserve Amount = (Year One Principal ($/yr) + Year One Interest ($/yr)) × Debt Service Reserve Account (months) / 12 (months/yr)

Tip. Debt Service Reserve Accounts for utility-scale projects are typically sized to cover 6 to 12 months of principal and interest payments.

Major Equipment Replacement Reserve Accounts

Major equipment replacement reserves are funds that the project sets aside to cover the cost of replacing equipment during the analysis period. You can specify up to three replacement reserve accounts.

SAM assumes that the cost of each major equipment replacement is capitalized rather than expensed. You can specify a depreciation schedule for each the major equipment replacement cost.

SAM calculates the inflation-adjusted cost of each major equipment replacement and funds a reserve account in each of the replacement cycle. At the time of the major equipment replacement, funds are released from the reserve account in an amount sufficient to cover the expense.

Account Name

The name of the reserve account for your reference. SAM reports value associated with each account in the cash flow and other graphs and tables using the name Reserve Account 1, 2, and 3, regardless of the name you enter.

Replacement Cost

The cost in Year One dollars per kW of nameplate capacity.

Replacement Cost ($) = Replacement Cost (Year One $/kW) × Nameplate Capacity (kW)

Replacement Frequency

The frequency in years that the replacement cost occurs.

For example, a replacement cost of $10,000 and frequency of 5 years results in an inflation-adjusted major equipment capital spending amount of $10,000 occurring in Years 5, 10, 15, 20, etc.

Depreciation Treatment For All Capital Expenditure

Specify a federal and state depreciation method for the major equipment replacement cost.

SAM includes major equipment replacement reserves in the annual total depreciation amount in the cash flow.

13.7 Utility All Equity Partnership Flip

This topic describes the inputs on the Financing page for the Utility All Equity Partnership Flip financing option. For a general description of financial structures SAM can model, see Financing Overview.

SAM displays results of the financial model in the cash flow. See Cash Flow Variables for details.

Solution Mode

The solution mode determines whether SAM calculates a PPA price based on IRR targets that you specify, or an IRR based on a PPA price that you specify.

- Specify IRR Target allows you to specify the IRR as an input, and SAM uses a search algorithm to find the PPA price required to meet the target IRR.
- Specify PPA Price allows you to specify the PPA price as an input, and SAM calculates the resulting IRR.

Solution Mode 1: Specify IRR Target

The Specify IRR Target option allows you to specify a desired IRR target and the year you would like the IRR to be achieved. SAM finds the PPA price required to meet the target given the financing assumptions and system costs you specify. For the partnership financing options that involve a tax investor and developer, you specify the target IRR from the tax investor's perspective.

SAM uses an iterative algorithm to search for the PPA price that meets the IRR target in the year you specify. If it cannot find a solution, it finds the PPA price that results in an IRR and year as close as possible to the target values, and reports the IRR and year in results as "actual" values.

Notes.

In some cases, the actual values may differ significantly from the target values. If you are not satisfied with the actual values, you can adjust your assumptions and rerun simulations until the actual and target values match.

If your analysis involves time-of-delivery (TOD) factors, see the notes under the Solution Mode 2 description below.

After running simulations, SAM shows both the target values and the actual values in the Metrics table. For the partnership financing options that involve a tax investor and developer, SAM shows the IRR for both partners.

IRR Target

The desired IRR target as a percentage:

- For the Single Owner option the required IRR is the project IRR.
- For the All Equity and Leveraged Partnership Flip options and Sale Leaseback option, the target IRR is the tax investor IRR. SAM calculates the developer IRR as a function of the value in excess of the tax investor IRR.

Tip. SAM assumes a default tax equity return rate of 8.5% for the All Equity Partnership Flip option and a default rate of 10.5% for the Leveraged Partnership Flip option. In practice, tax investors may accept lower or require higher returns for specific projects than these rates, depending on project size, market conditions, and perceived project risks.The solution mode determines whether SAM calculates a PPA price based on an IRR that you specify or whether SAM calculates IRR values based on a PPA price that you specify.

Target Year

The year in which the target IRR will be achieved. For the partnership flip options, this is the flip year when project returns switch from the tax investor (pre-flip) to the developer (post-flip).

Solution Mode 2: Specify PPA Price

The Specify PPA Price option allows you to specify a power purchase bid price:

- For the Single Owner option, SAM calculates the project IRR.

- For All Equity and Leveraged Partnership Flip options, and Sale Leaseback option that involve two parties, SAM calculates two IRR values: One from the tax investor perspective, and one from the developer perspective. For the partnership flip options, SAM also calculates the flip year when project returns switch from the tax investor to the developer.

After running simulations, SAM shows the IRR values in the Metrics table and cash flow.

Note. For the Specify PPA Price option, the IRR target year, IRR target, IRR actual year, and IRR in target years shown in the Metrics table are not valid results because these values do not apply to the option.

PPA Price

The power price in cents per kWh. This is the price that would be negotiated as part of a power purchase agreement.

Escalation Rate

An escalation rate applied to the PPA price in Year One to calculate the electricity sales price in years two and later in the project cash flow.

SAM does not apply the inflation rate to the PPA price. If you do not specify a PPA price escalation rate, SAM assumes that the same price applies in all years of the analysis period.

Notes.

For most analyses, the PPA price is equal to the PPA price in Year One of the cash flow. The price in Years two and later is the PPA price adjusted by the optional escalation rate.

If your analysis involves TOD factors, the Year One PPA price is the PPA price that you specify on the Financing page adjusted by the time-of-delivery (TOD) factors and schedule that you specify either on the Time of Delivery Factors page, or for concentrating solar power (CSP) systems, on the Thermal Energy Storage page.

Equity Structure

The Equity Structure variables determine how project income is divided between the tax investor and developer before and after the flip year.

The flip year is the year in the project cash flow that the tax investor IRR target is met. Typically, the majority of project cash and tax benefits is allocated to the tax investor before the flip year, and to the developer after the flip year. For example, the pre-flip tax investor share might be 98% (2% developer share), and the post-flip tax investor share might be 10% (90% developer share).

Tax Investor

The tax investor's share of the project investment, revenue, and tax benefits before and after the flip year.

Equity Investment

The tax investor's share of the project equity requirement as a percentage of:

- For Leveraged Partnership Flip, the total installed cost less the debt amount.
- For All Equity Partnership Flip, the total installed cost.

Share of Project Cash, Pre-flip

The percentage of annual project cash returns allocated to the tax investor in years before the flip target is reached.

Share of Project Cash, Post-flip

The percentage of annual project cash returns allocated to the tax investor in years after the flip target is reached.

Share of Tax Benefits, Pre-flip

The percentage of taxable income and any tax benefits, including depreciation-related tax losses and ITC-related tax credits, allocated to the tax investor before the flip target is reached.

Share of Tax Benefits, Post-flip

The percentage of taxable income and any tax benefits, including depreciation-related tax losses and ITC-related tax credits, allocated to the tax investor after the flip target is reached.

Developer

The developer's initial capital contribution and share of cash and tax flows are based on the tax investor quantities.

SAM calculates these values by subtracting the tax investor quantities from 100%. You cannot directly edit these values. To change the values, edit values under **Tax Investor**.

Developer Capital Recovery

The Developer Capital Recovery options determine the timing of cash flows to the developer.

During the capital recovery period, the developer cannot receive an amount of cash greater than its initial investment.

Time

Choose this option to specify the duration of the developer's capital recovery period.

Full Capital Recovery

Choose this option to allocate 100% of the project cash flow to the developer until the developer recovers its investment. Note that there is no return on investment, just a return of investment.

Duration

The number of years during which the developer receives 100% of the project cash flow. If the number of years exceeds the time required for full capital recovery the developer only receives 100% of the project cash for years up to the year the developer recovers its investment.

Analysis Parameters

The analysis parameters specify the analysis period, inflation rate and discount rate.

Analysis Period

Number of years covered by the analysis. Typically equivalent to the project or investment life. The analysis period determines the number of years in the project cash flow.

Inflation Rate

Annual rate of change of costs, typically based on a price index. SAM uses the inflation rate to calculate the value of costs in years two and later of the project cash flow based on Year One dollar values that you specify on the System Costs page, Financing page, Utility Rate page, Incentives, or pages.

The default value of 2.5% is based on consumer price index data from the U.S. Department of Labor Bureau of Labor Statistics, and is the average of the annual average consumer price index between 1991 and 2012.

Real Discount Rate

A measure of the time value of money expressed as an annual rate. SAM uses the real discount rate to calculate the present value (value in year one) of dollar amounts in the project cash flow over the analysis period and to calculate annualized costs.

Note. For projects with one of the Utility or Commercial PPA financing options, SAM includes both a discount rate and internal rate of return (IRR) in the analysis. For these projects, the discount rate represents the value of an alternative investment, and the IRR can represent a profit requirement or the risk associated with the project. For example, the IRR may be higher than the discount rate for a renewable energy project with higher risk than an alternative investment.

Nominal Discount Rate

SAM calculates the nominal discount based on the values of the real discount rate and the inflation rate:

Nominal Discount Rate = (1 + Real Discount Rate) × (1 + Inflation Rate) - 1

Tax and Insurance Rates

Federal and State Income Tax Rates

The annual federal and state income tax rate applies to taxable income and is used to calculate tax benefits or liabilities.

For all projects, taxable income includes income from any incentives marked on the Incentives page as taxable.

For residential and commercial projects, SAM does not consider the value of electricity saved by the system to be income. However, for commercial projects, because those savings represent the value of electricity purchases that would have been a tax-deductible operating expense to the commercial entity, SAM does reduce the project after-tax cash flow by the amount of federal and state income tax on the value of the electricity. In other words, with the renewable energy system in place, the commercial entity must pay tax on that portion of its income that it would have deducted as an operating expense.

For commercial PPA and utility IPP projects, the energy value represents electricity sales that are taxable income.

Sales Tax

The sales tax is a one-time tax that SAM includes in the project's total installed cost. SAM calculates the sales tax amount by multiplying the sales tax rate on the Financing page by the rate you specify under Indirect Capital Costs and the Total Direct Cost on the System Costs page.

For tax purposes, because SAM includes the sales tax amount in the total installed cost, it treats sales tax as part of the cost of property. For projects with depreciation (Commercial and Utility financing options only), SAM includes the sales tax amount in the depreciable basis. See IRS Publication 551, Basis of Assets, for more details.

Some states and other jurisdictions offer a sales tax exemption for renewable energy projects. To model a sales tax exemption in SAM, reduce the sales tax percentage as appropriate. For example, for a 100% sales tax exemption, enter a sales tax rate of zero.

For projects with debt, because SAM includes the sales tax amount in the total installed cost, the sales tax influences the debt amount and debt interest payment. For projects where debt interest payments are deductible from federal and state income tax (all financing options except Residential with standard loan), SAM includes sales tax in the calculation of the deductions.

Insurance Rate (Annual)

The annual insurance rate applies to the total installed cost of the project. SAM treats insurance as an operating cost for each year. The insurance cost in year one of the project cash flow is the insurance rate multiplied by the total installed cost from the System Costs page. The first year cost is then increased by inflation in each subsequent year. For commercial and utility projects, the insurance cost is an operating expense and therefore reduces federal and state taxable income.

Property Tax

Property tax is an annual project expense that SAM includes under Operating Expenses in the cash flow.

SAM treats property tax as a tax-deductible operating expense for each year. In each year of the project cash flow, the property tax cost is the property tax rate multiplied by the assessed value for that year.

SAM determines the annual property tax payment by calculating an assessed value for each year in the cash flow, and applying the assessed percent to that value. The assessed value may decline from year to year at the rate you specify. The assessed percent and tax rate both remain constant from year to year.

For residential projects, the property tax amount is the only operating cost that can be deducted from state and federal income tax.

Note. For the residential and commercial financing option, SAM calculates a real estate value added amount for each year in the analysis period. SAM does not use the value to calculate property tax, or to calculate financial metrics such as LCOE or NPV. You can find the value on the Results page Tables under **Annual Data**.

Assessed Percent

The assessed value of property subject to property taxes as a percentage of the system total installed cost specified on the System Costs page. SAM uses this value to calculate the assessed property value in year one of the project cash flow.

Assessed Value

The assessed property value in Year One of the project cash flow:

Assessed Value ($) = Assessed Percent (%) × Total Installed Cost ($)

Where Total Installed Cost is from the System Costs page.

Assessed Value Decline

The annual decline in the assessed property value. SAM uses this value to calculate the property assessed value in years two and later of the project cash flow. For an assessed value that does not decrease annually, specify a value of zero percent per year.

Property Tax

The annual property tax rate applies to the assessed value of the project in each year of the project cash flow.

Salvage Value

SAM considers the salvage value to be project income in the final year of the project cash flow, and calculates the value as a percentage of the total installed cost from the System Costs page.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period. SAM reports the salvage value amount in the final year of the project cash flow under Operating Expenses.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

For residential projects, the salvage value has no effect on federal and state income tax.

For commercial and utility projects, the salvage value is treated as a source of pre-tax revenue in the final year of the analysis period, increasing the federal and state taxable income.

Net Salvage Value

The salvage value as a percentage of the project's total installed cost from the System Costs page.

End of Analysis Period Salvage Value

The salvage value dollar amount that will appear in final year of the project cash flow.

End of Analysis Period Salvage Value ($) = Net Salvage Value (%) × Total Installed Cost ($)

Where *Total Installed Cost* is from the System Costs page.

Construction Financing

SAM allows you to specify parameters for up to five construction loans to approximate interest during construction (IDC) that SAM considers to be a cost to the project.

SAM assumes that 100% of the construction balance is outstanding for half of the construction period, which is equivalent to an even monthly draw schedule with an average loan life of half of the construction period. To approximate a different draw schedule, you could adjust the loan's interest rate accordingly.

Note. To model a project with no construction period loans, set the **Percent of Installed Costs** value for each of the five loans to zero.

For the Commercial PPA and Independent Power Producer options, SAM includes the total construction financing cost in the project loan principal amount shown on the Financing page.

For the partnership flip, sale leaseback, and single owner options, SAM includes the total construction financing cost in the Financing Cost reported in the Metrics table. The financing cost, in turn, is part of issuance of equity value reported in the project cash flow.

Construction Loans

SAM allows you to specify up to five construction loans. You can type a name describing each loan or use the default names.

Percent of Installed Costs

The amount borrowed for the construction loan as a percentage of the total installed cost, assuming that all construction costs are included in the installation costs you specify on the System Costs page. Specify a non-zero percentage for each construction period loan you want to include in the analysis.

The sum of the up to five percentage values you specify for each construction loan must be 100%.

Up-front Fee

A percentage of the principal amount, typically between 1% and 3% that SAM adds to the interest amount for each construction loan to calculate the total construction financing cost. Note that no interest applies to the up-front fee.

Up-front Fee Amount ($) = Principal Amount ($) × Up-front Fee Percentage (%)

Months Prior to Operation

The loan period for the construction loan in months.

Annual Interest Rate

The construction loan interest rate as an annual percentage.

Principal

The amount borrowed for each construction period loan:

Principal Amount ($) = Total Installed Cost ($) × Percent of Installed Costs (%)

Interest

The total interest payment due for each construction period loan, assuming that 100% of the construction balance is outstanding for half of the construction period.

Interest ($) = Principal Amount ($) × Loan Rate (%/yr) / 12 (mos/yr) × 0.5

Total Construction Financing Cost

SAM includes the total construction financing cost in the project cost.

Total Construction Financing Cost = Interest + Up-front Fee Amount

Cost of Acquiring Financing

The Cost of Acquiring Financing input values represent the cost of securing debt or the participation of tax investors.

Financing Cost (Single Owner only)

The dollar amount associated with acquiring financing.

Development Fee (All options except Single Owner)

A fee paid to the developer in Year 0, specified as a percentage of the total installed cost on the System Costs page.

Development Fee ($) = Development Fee (%) × Total Installed Cost ($)

Equity Closing Cost (All options except Single Owner)

A dollar amount representing costs associated with securing participation of a tax investor, such as consultants and legal fees.

Other Financing Costs (All options except Single Owner)

A dollar amount for financing costs not included in the equity closing cost or development fee.

SAM calculates the project's total cost of financing and reports it as the Financing Cost in the Metrics table, which is part of the issuance of equity value reported in the cash flow.

Reserve Accounts

Interest on Reserves

Annual interest rate earned on funds in reserve accounts. The different financing options have different reserve accounts, and the interest on reserves rate applies to all of the accounts available for a given option:

- Working capital reserve account, specified under Cost of Acquiring Financing.
- Major equipment reserve account, specified under Major Equipment Replacement Reserves.
- Debt service reserve account (Leveraged Partnership Flip, Single Owner), specified under Debt Service.
- Lessee reserve account (Sale Leaseback), specified under Sale Leaseback.

Working Capital Reserve Account

The size of the working capital reserve in months of operation.

Working Capital Reserve Amount = Months of Operating Costs (months) / 12 months/yr × Year One Total Expenses ($/yr)

Debt Service Reserve Account

A debt service reserve account is a fund that may be required by the project debt provider. The account is funded in Year 0 and earns interest in Years 1 and later at the reserve interest rate specified under Reserves. Once debt has been repaid, the funds in the account are released to the project cash flow.

The number of months of principal and interest payments in Year One whose value is equivalent to the size of the debt reserve account in Year 0.

SAM calculates the reserve account size in Year 0 based on the principal and interest amounts in Year One:

Year 0 Debt Service Reserve Amount = (Year One Principal ($/yr) + Year One Interest ($/yr)) × Debt Service Reserve Account (months) / 12 (months/yr)

Tip. Debt Service Reserve Accounts for utility-scale projects are typically sized to cover 6 to 12 months of principal and interest payments.

Major Equipment Replacement Reserve Accounts

Major equipment replacement reserves are funds that the project sets aside to cover the cost of replacing equipment during the analysis period. You can specify up to three replacement reserve accounts.

SAM assumes that the cost of each major equipment replacement is capitalized rather than expensed. You can specify a depreciation schedule for each the major equipment replacement cost.

SAM calculates the inflation-adjusted cost of each major equipment replacement and funds a reserve account in each of the replacement cycle. At the time of the major equipment replacement, funds are released from the reserve account in an amount sufficient to cover the expense.

Account Name

The name of the reserve account for your reference. SAM reports value associated with each account in the cash flow and other graphs and tables using the name Reserve Account 1, 2, and 3, regardless of the name you enter.

Replacement Cost

The cost in Year One dollars per kW of nameplate capacity.

Replacement Cost ($) = Replacement Cost (Year One $/kW) × Nameplate Capacity (kW)

Replacement Frequency

The frequency in years that the replacement cost occurs.

For example, a replacement cost of $10,000 and frequency of 5 years results in an inflation-adjusted major equipment capital spending amount of $10,000 occurring in Years 5, 10, 15, 20, etc.

Depreciation Treatment For All Capital Expenditure

Specify a federal and state depreciation method for the major equipment replacement cost.

SAM includes major equipment replacement reserves in the annual total depreciation amount in the cash flow.

13.8 Utility Leveraged Partnership Flip

This topic describes the inputs on the Financing page for the Utility Leveraged Partnership Flip financing option. For a general description of financial structures SAM can model, see Financing Overview.

SAM displays results of the financial model in the cash flow. See Cash Flow Variables for details.

Solution Mode

The solution mode determines whether SAM calculates a PPA price based on IRR targets that you specify, or an IRR based on a PPA price that you specify.

- Specify IRR Target allows you to specify the IRR as an input, and SAM uses a search algorithm to find the PPA price required to meet the target IRR.
- Specify PPA Price allows you to specify the PPA price as an input, and SAM calculates the resulting IRR.

Solution Mode 1: Specify IRR Target

The Specify IRR Target option allows you to specify a desired IRR target and the year you would like the IRR to be achieved. SAM finds the PPA price required to meet the target given the financing assumptions and system costs you specify. For the partnership financing options that involve a tax investor and developer, you specify the target IRR from the tax investor's perspective.

SAM uses an iterative algorithm to search for the PPA price that meets the IRR target in the year you specify. If it cannot find a solution, it finds the PPA price that results in an IRR and year as close as possible to the target values, and reports the IRR and year in results as "actual" values.

Notes.

In some cases, the actual values may differ significantly from the target values. If you are not satisfied with the actual values, you can adjust your assumptions and rerun simulations until the actual and target values match.

If your analysis involves time-of-delivery (TOD) factors, see the notes under the Solution Mode 2 description below.

After running simulations, SAM shows both the target values and the actual values in the Metrics table. For the partnership financing options that involve a tax investor and developer, SAM shows the IRR for both partners.

IRR Target

The desired IRR target as a percentage:

- For the Single Owner option the required IRR is the project IRR.
- For the All Equity and Leveraged Partnership Flip options and Sale Leaseback option, the target IRR is the tax investor IRR. SAM calculates the developer IRR as a function of the value in excess of the tax investor IRR.

Tip. SAM assumes a default tax equity return rate of 8.5% for the All Equity Partnership Flip option and a default rate of 10.5% for the Leveraged Partnership Flip option. In practice, tax investors may accept lower or require higher returns for specific projects than these rates, depending on project size, market conditions, and perceived project risks.The solution mode determines whether SAM calculates a PPA price based on an IRR that you specify or whether SAM calculates IRR values based on a PPA price that you specify.

Target Year

The year in which the target IRR will be achieved. For the partnership flip options, this is the flip year when project returns switch from the tax investor (pre-flip) to the developer (post-flip).

Solution Mode 2: Specify PPA Price

The Specify PPA Price option allows you to specify a power purchase bid price:

- For the Single Owner option, SAM calculates the project IRR.
- For All Equity and Leveraged Partnership Flip options, and Sale Leaseback option that involve two parties, SAM calculates two IRR values: One from the tax investor perspective, and one from the developer perspective. For the partnership flip options, SAM also calculates the flip year when project returns switch from the tax investor to the developer.

After running simulations, SAM shows the IRR values in the Metrics table and cash flow.

Note. For the Specify PPA Price option, the IRR target year, IRR target, IRR actual year, and IRR in target years shown in the Metrics table are not valid results because these values do not apply to the option.

PPA Price

The power price in cents per kWh. This is the price that would be negotiated as part of a power purchase agreement.

Escalation Rate

An escalation rate applied to the PPA price in Year One to calculate the electricity sales price in years two and later in the project cash flow.

SAM does not apply the inflation rate to the PPA price. If you do not specify a PPA price escalation rate, SAM assumes that the same price applies in all years of the analysis period.

Notes.

For most analyses, the PPA price is equal to the PPA price in Year One of the cash flow. The price in Years two and later is the PPA price adjusted by the optional escalation rate.

If your analysis involves TOD factors, the Year One PPA price is the PPA price that you specify on the Financing page adjusted by the time-of-delivery (TOD) factors and schedule that you specify either on the Time of Delivery Factors page, or for concentrating solar power (CSP) systems, on the Thermal Energy Storage page.

Equity Structure

The Equity Structure variables determine how project income is divided between the tax investor and developer before and after the flip year.

The flip year is the year in the project cash flow that the tax investor IRR target is met. Typically, the majority of project cash and tax benefits is allocated to the tax investor before the flip year, and to the developer after the flip year. For example, the pre-flip tax investor share might be 98% (2% developer share), and the post-flip tax investor share might be 10% (90% developer share).

Tax Investor

The tax investor's share of the project investment, revenue, and tax benefits before and after the flip year.

Equity Investment

The tax investor's share of the project equity requirement as a percentage of:

- For Leveraged Partnership Flip, the total installed cost less the debt amount.
- For All Equity Partnership Flip, the total installed cost.

Share of Project Cash, Pre-flip

The percentage of annual project cash returns allocated to the tax investor in years before the flip target is reached.

Share of Project Cash, Post-flip

The percentage of annual project cash returns allocated to the tax investor in years after the flip target is reached.

Share of Tax Benefits, Pre-flip

The percentage of taxable income and any tax benefits, including depreciation-related tax losses and ITC-related tax credits, allocated to the tax investor before the flip target is reached.

Share of Tax Benefits, Post-flip

The percentage of taxable income and any tax benefits, including depreciation-related tax losses and ITC-related tax credits, allocated to the tax investor after the flip target is reached.

Developer

The developer's initial capital contribution and share of cash and tax flows are based on the tax investor quantities.

SAM calculates these values by subtracting the tax investor quantities from 100%. You cannot directly edit these values. To change the values, edit values under **Tax Investor**.

Analysis Parameters

The analysis parameters specify the analysis period, inflation rate and discount rate.

Analysis Period

Number of years covered by the analysis. Typically equivalent to the project or investment life. The analysis period determines the number of years in the project cash flow.

Inflation Rate

Annual rate of change of costs, typically based on a price index. SAM uses the inflation rate to calculate the value of costs in years two and later of the project cash flow based on Year One dollar values that you specify on the System Costs page, Financing page, Utility Rate page, Incentives, or pages.

The default value of 2.5% is based on consumer price index data from the U.S. Department of Labor Bureau of Labor Statistics, and is the average of the annual average consumer price index between 1991 and 2012.

Real Discount Rate

A measure of the time value of money expressed as an annual rate. SAM uses the real discount rate to calculate the present value (value in year one) of dollar amounts in the project cash flow over the analysis period and to calculate annualized costs.

> **Note.** For projects with one of the Utility or Commercial PPA financing options, SAM includes both a discount rate and internal rate of return (IRR) in the analysis. For these projects, the discount rate represents the value of an alternative investment, and the IRR can represent a profit requirement or the risk associated with the project. For example, the IRR may be higher than the discount rate for a renewable energy project with higher risk than an alternative investment.

Nominal Discount Rate

SAM calculates the nominal discount based on the values of the real discount rate and the inflation rate:

Nominal Discount Rate = (1 + Real Discount Rate) × (1 + Inflation Rate) - 1

Tax and Insurance Rates

Federal and State Income Tax Rates

The annual federal and state income tax rate applies to taxable income and is used to calculate tax benefits or liabilities.

For all projects, taxable income includes income from any incentives marked on the Incentives page as taxable.

For residential and commercial projects, SAM does not consider the value of electricity saved by the system to be income. However, for commercial projects, because those savings represent the value of electricity purchases that would have been a tax-deductible operating expense to the commercial entity, SAM does reduce the project after-tax cash flow by the amount of federal and state income tax on the value of the electricity. In other words, with the renewable energy system in place, the commercial entity must pay tax on that portion of its income that it would have deducted as an operating expense.

For commercial PPA and utility IPP projects, the energy value represents electricity sales that are taxable income.

Sales Tax

The sales tax is a one-time tax that SAM includes in the project's total installed cost. SAM calculates the sales tax amount by multiplying the sales tax rate on the Financing page by the rate you specify under Indirect Capital Costs and the Total Direct Cost on the System Costs page.

For tax purposes, because SAM includes the sales tax amount in the total installed cost, it treats sales tax as part of the cost of property. For projects with depreciation (Commercial and Utility financing options only), SAM includes the sales tax amount in the depreciable basis. See IRS Publication 551, Basis of Assets, for more details.

Some states and other jurisdictions offer a sales tax exemption for renewable energy projects. To model a sales tax exemption in SAM, reduce the sales tax percentage as appropriate. For example, for a 100% sales tax exemption, enter a sales tax rate of zero.

For projects with debt, because SAM includes the sales tax amount in the total installed cost, the sales tax influences the debt amount and debt interest payment. For projects where debt interest payments are deductible from federal and state income tax (all financing options except Residential with standard loan), SAM includes sales tax in the calculation of the deductions.

Insurance Rate (Annual)

The annual insurance rate applies to the total installed cost of the project. SAM treats insurance as an operating cost for each year. The insurance cost in year one of the project cash flow is the insurance rate multiplied by the total installed cost from the System Costs page. The first year cost is then increased by inflation in each subsequent year. For commercial and utility projects, the insurance cost is an operating expense and therefore reduces federal and state taxable income.

Property Tax

Property tax is an annual project expense that SAM includes under Operating Expenses in the cash flow.

SAM treats property tax as a tax-deductible operating expense for each year. In each year of the project cash flow, the property tax cost is the property tax rate multiplied by the assessed value for that year.

SAM determines the annual property tax payment by calculating an assessed value for each year in the cash flow, and applying the assessed percent to that value. The assessed value may decline from year to year at the rate you specify. The assessed percent and tax rate both remain constant from year to year.

For residential projects, the property tax amount is the only operating cost that can be deducted from state and federal income tax.

> **Note.** For the residential and commercial financing option, SAM calculates a real estate value added amount for each year in the analysis period. SAM does not use the value to calculate property tax, or to calculate financial metrics such as LCOE or NPV. You can find the value on the Results page Tables under **Annual Data**.

Assessed Percent

The assessed value of property subject to property taxes as a percentage of the system total installed cost specified on the System Costs page. SAM uses this value to calculate the assessed property value in year one of the project cash flow.

Assessed Value

The assessed property value in Year One of the project cash flow:

Assessed Value ($) = Assessed Percent (%) × Total Installed Cost ($)

Where Total Installed Cost is from the System Costs page.

Assessed Value Decline

The annual decline in the assessed property value. SAM uses this value to calculate the property assessed value in years two and later of the project cash flow. For an assessed value that does not decrease annually, specify a value of zero percent per year.

Property Tax

The annual property tax rate applies to the assessed value of the project in each year of the project cash flow.

Salvage Value

SAM considers the salvage value to be project income in the final year of the project cash flow, and calculates the value as a percentage of the total installed cost from the System Costs page.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period. SAM reports the salvage value amount in the final year of the project cash flow under Operating Expenses.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

For residential projects, the salvage value has no effect on federal and state income tax.

For commercial and utility projects, the salvage value is treated as a source of pre-tax revenue in the final year of the analysis period, increasing the federal and state taxable income.

Net Salvage Value

The salvage value as a percentage of the project's total installed cost from the System Costs page.

End of Analysis Period Salvage Value

The salvage value dollar amount that will appear in final year of the project cash flow.

End of Analysis Period Salvage Value ($) = Net Salvage Value (%) × Total Installed Cost ($)

Where *Total Installed Cost* is from the System Costs page.

Construction Financing

SAM allows you to specify parameters for up to five construction loans to approximate interest during construction (IDC) that SAM considers to be a cost to the project.

SAM assumes that 100% of the construction balance is outstanding for half of the construction period, which is equivalent to an even monthly draw schedule with an average loan life of half of the construction period. To approximate a different draw schedule, you could adjust the loan's interest rate accordingly.

Note. To model a project with no construction period loans, set the **Percent of Installed Costs** value for each of the five loans to zero.

For the Commercial PPA and Independent Power Producer options, SAM includes the total construction financing cost in the project loan principal amount shown on the Financing page.

For the partnership flip, sale leaseback, and single owner options, SAM includes the total construction financing cost in the Financing Cost reported in the Metrics table. The financing cost, in turn, is part of issuance of equity value reported in the project cash flow.

Construction Loans

SAM allows you to specify up to five construction loans. You can type a name describing each loan or use the default names.

Percent of Installed Costs

The amount borrowed for the construction loan as a percentage of the total installed cost, assuming that all construction costs are included in the installation costs you specify on the System Costs page. Specify a non-zero percentage for each construction period loan you want to include in the analysis.

The sum of the up to five percentage values you specify for each construction loan must be 100%.

Up-front Fee

A percentage of the principal amount, typically between 1% and 3% that SAM adds to the interest amount for each construction loan to calculate the total construction financing cost. Note that no interest applies to the up-front fee.

Up-front Fee Amount ($) = Principal Amount ($) × Up-front Fee Percentage (%)

Months Prior to Operation

The loan period for the construction loan in months.

Annual Interest Rate

The construction loan interest rate as an annual percentage.

Principal

The amount borrowed for each construction period loan:

Principal Amount ($) = Total Installed Cost ($) × Percent of Installed Costs (%)

Interest

The total interest payment due for each construction period loan, assuming that 100% of the construction balance is outstanding for half of the construction period.

Interest ($) = Principal Amount ($) × Loan Rate (%/yr) / 12 (mos/yr) × 0.5

Total Construction Financing Cost

SAM includes the total construction financing cost in the project cost.

Total Construction Financing Cost = Interest + Up-front Fee Amount

Project Term Debt

The Project Term Debt input variables determine the quantity and cost of debt. SAM calculates the debt fraction as a result based on the debt terms you specify here.

Debt Service Coverage Ratio (DSCR)

The ratio of annual cash available for debt service to the sum of the annual principal and interest payment.

Annual cash available for debt service is equal to the Earnings Before Interest Taxes Depreciation and Amortization (EBITDA) value shown in the cash flow less cash used to fund the major equipment replacement reserves.

SAM assumes that the debt service coverage ratio remains constant over the analysis period. To model a project with a debt-service ratio that varies from year to year, use the utility IPP financing option, which allows you to specify a minimum debt-service coverage ratio.

Tip. The DSCR generally ranges between 1.40 and 1.50 for proven wind technology. For solar, the ratios are slightly lower: In the 1.30 to 1.40 range for PV, and perhaps slightly lower for CSP and CPV technologies.

Tenor

The loan period in years.

Annual All-In Interest Rate

Annual loan interest rate.

Debt Closing Costs

A dollar amount representing debt closing costs.

Up-Front Fee

A percentage of the total debt representing debt closing costs.

Note. SAM considers debt closing costs and up-front fee to be part of the project's Financing Cost reported in the Metrics table, which is part of the issuance of equity value reported in the cash flow.

Production Based Incentives (PBI) Available for Debt Service

If you specified one or more production-based incentives on the Incentives page, and the incentives can be used to service debt, check the box for the incentive.

For example, if you specified a Utility PBI on the Cash Incentives page that can be used to service debt, check the Utility box.

When you check the option for a PBI, SAM includes the PBI amount in the total revenue amount that is used to calculate the DSCR, and is reported in the project cash flow.

Cost of Acquiring Financing

The Cost of Acquiring Financing input values represent the cost of securing debt or the participation of tax investors.

Financing Cost (Single Owner only)

The dollar amount associated with acquiring financing.

Development Fee (All options except Single Owner)

A fee paid to the developer in Year 0, specified as a percentage of the total installed cost on the System Costs page.

Development Fee ($) = Development Fee (%) × Total Installed Cost ($)

Equity Closing Cost (All options except Single Owner)

A dollar amount representing costs associated with securing participation of a tax investor, such as consultants and legal fees.

Other Financing Costs (All options except Single Owner)

A dollar amount for financing costs not included in the equity closing cost or development fee.

SAM calculates the project's total cost of financing and reports it as the Financing Cost in the Metrics table, which is part of the issuance of equity value reported in the cash flow.

Reserve Accounts

Interest on Reserves

Annual interest rate earned on funds in reserve accounts. The different financing options have different reserve accounts, and the interest on reserves rate applies to all of the accounts available for a given option:

- Working capital reserve account, specified under Cost of Acquiring Financing.
- Major equipment reserve account, specified under Major Equipment Replacement Reserves.
- Debt service reserve account (Leveraged Partnership Flip, Single Owner), specified under Debt Service.
- Lessee reserve account (Sale Leaseback), specified under Sale Leaseback.

Working Capital Reserve Account

The size of the working capital reserve in months of operation.

Working Capital Reserve Amount = Months of Operating Costs (months) / 12 months/yr × Year One Total Expenses ($/yr)

Debt Service Reserve Account

A debt service reserve account is a fund that may be required by the project debt provider. The account is funded in Year 0 and earns interest in Years 1 and later at the reserve interest rate specified under Reserves. Once debt has been repaid, the funds in the account are released to the project cash flow.

The number of months of principal and interest payments in Year One whose value is equivalent to the size of the debt reserve account in Year 0.

SAM calculates the reserve account size in Year 0 based on the principal and interest amounts in Year One:

Year 0 Debt Service Reserve Amount = (Year One Principal ($/yr) + Year One Interest ($/yr)) × Debt Service Reserve Account (months) / 12 (months/yr)

Tip. Debt Service Reserve Accounts for utility-scale projects are typically sized to cover 6 to 12 months of principal and interest payments.

Major Equipment Replacement Reserve Accounts

Major equipment replacement reserves are funds that the project sets aside to cover the cost of replacing equipment during the analysis period. You can specify up to three replacement reserve accounts.

SAM assumes that the cost of each major equipment replacement is capitalized rather than expensed. You can specify a depreciation schedule for each the major equipment replacement cost.

SAM calculates the inflation-adjusted cost of each major equipment replacement and funds a reserve account in each of the replacement cycle. At the time of the major equipment replacement, funds are released from the reserve account in an amount sufficient to cover the expense.

Account Name

The name of the reserve account for your reference. SAM reports value associated with each account in the cash flow and other graphs and tables using the name Reserve Account 1, 2, and 3, regardless of the name you enter.

Replacement Cost

The cost in Year One dollars per kW of nameplate capacity.

Replacement Cost ($) = Replacement Cost (Year One $/kW) × Nameplate Capacity (kW)

Replacement Frequency

The frequency in years that the replacement cost occurs.

For example, a replacement cost of $10,000 and frequency of 5 years results in an inflation-adjusted major equipment capital spending amount of $10,000 occurring in Years 5, 10, 15, 20, etc.

Depreciation Treatment For All Capital Expenditure

Specify a federal and state depreciation method for the major equipment replacement cost.

SAM includes major equipment replacement reserves in the annual total depreciation amount in the cash flow.

13.9 Utility Sale Leaseback

This topic describes the inputs on the Financing page for the Utility Sale Leaseback financing option. For a general description of financial structures SAM can model, see Financing Overview.

SAM displays results of the financial model in the cash flow. See Cash Flow Variables for details.

Solution Mode

The solution mode determines whether SAM calculates a PPA price based on IRR targets that you specify, or an IRR based on a PPA price that you specify.

- Specify IRR Target allows you to specify the IRR as an input, and SAM uses a search algorithm to find the PPA price required to meet the target IRR.
- Specify PPA Price allows you to specify the PPA price as an input, and SAM calculates the resulting IRR.

Solution Mode 1: Specify IRR Target

The Specify IRR Target option allows you to specify a desired IRR target and the year you would like the IRR to be achieved. SAM finds the PPA price required to meet the target given the financing assumptions and system costs you specify. For the partnership financing options that involve a tax investor and developer, you specify the target IRR from the tax investor's perspective.

SAM uses an iterative algorithm to search for the PPA price that meets the IRR target in the year you specify. If it cannot find a solution, it finds the PPA price that results in an IRR and year as close as possible to the target values, and reports the IRR and year in results as "actual" values.

Notes.

In some cases, the actual values may differ significantly from the target values. If you are not satisfied with the actual values, you can adjust your assumptions and rerun simulations until the actual and target values match.

If your analysis involves time-of-delivery (TOD) factors, see the notes under the Solution Mode 2 description below.

After running simulations, SAM shows both the target values and the actual values in the Metrics table. For the partnership financing options that involve a tax investor and developer, SAM shows the IRR for both partners.

IRR Target

The desired IRR target as a percentage:

- For the Single Owner option the required IRR is the project IRR.
- For the All Equity and Leveraged Partnership Flip options and Sale Leaseback option, the target IRR is the tax investor IRR. SAM calculates the developer IRR as a function of the value in excess of the tax investor IRR.

Tip. SAM assumes a default tax equity return rate of 8.5% for the All Equity Partnership Flip option and a default rate of 10.5% for the Leveraged Partnership Flip option. In practice, tax investors may accept lower or require higher returns for specific projects than these rates, depending on project size, market conditions, and perceived project risks.The solution mode determines whether SAM calculates a PPA price based on an IRR that you specify or whether SAM calculates IRR values based on a PPA price that you specify.

Target Year

The year in which the target IRR will be achieved. For the partnership flip options, this is the flip year when project returns switch from the tax investor (pre-flip) to the developer (post-flip).

Solution Mode 2: Specify PPA Price

The Specify PPA Price option allows you to specify a power purchase bid price:

- For the Single Owner option, SAM calculates the project IRR.
- For All Equity and Leveraged Partnership Flip options, and Sale Leaseback option that involve two parties, SAM calculates two IRR values: One from the tax investor perspective, and one from the developer perspective. For the partnership flip options, SAM also calculates the flip year when project returns switch from the tax investor to the developer.

After running simulations, SAM shows the IRR values in the Metrics table and cash flow.

Note. For the Specify PPA Price option, the IRR target year, IRR target, IRR actual year, and IRR in target years shown in the Metrics table are not valid results because these values do not apply to the option.

PPA Price

The power price in cents per kWh. This is the price that would be negotiated as part of a power purchase agreement.

Escalation Rate

An escalation rate applied to the PPA price in Year One to calculate the electricity sales price in years two and later in the project cash flow.

SAM does not apply the inflation rate to the PPA price. If you do not specify a PPA price escalation rate, SAM assumes that the same price applies in all years of the analysis period.

Notes.

For most analyses, the PPA price is equal to the PPA price in Year One of the cash flow. The price in Years two and later is the PPA price adjusted by the optional escalation rate.

If your analysis involves TOD factors, the Year One PPA price is the PPA price that you specify on the Financing page adjusted by the time-of-delivery (TOD) factors and schedule that you specify either on the Time of Delivery Factors page, or for concentrating solar power (CSP) systems, on the Thermal Energy Storage page.

Sale Leaseback

The Sale Leaseback input variables determine the developer's operating margin and size of the lease payment reserve account. SAM includes the developer's margin as a project expense in the cash flow.

Lessee Operating Margin

The developer's margin in dollars per kilowatt of system nameplate capacity.

Lessee Margin Escalation

An annual escalation rate that applies to the developer's margin. The inflation rate does not apply to the developer's margin.

Lessor Required Lease Payment Reserve

The size of the lease payment reserve account in months. (In some cases, the tax investor may require that the developer fund a reserve account.)

Lease Reserve Amount ($) = Lessor Required Lease Payment Reserve (months) / 12 (months/yr) × Year 1 Pre-tax Operating Cash Flow ($/yr)

The lease reserve amount is part of the project Financing Cost reported on the Metrics table, which is included in the issuance of equity value in the cash flow.

Amount

This amount of the developer's margin.

Amount ($) = Lessee Operating Margin ($/kW) × System Nameplate Capacity (kW)

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 16. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

Analysis Parameters

The analysis parameters specify the analysis period, inflation rate and discount rate.

Analysis Period

Number of years covered by the analysis. Typically equivalent to the project or investment life. The analysis period determines the number of years in the project cash flow.

Inflation Rate

Annual rate of change of costs, typically based on a price index. SAM uses the inflation rate to calculate the value of costs in years two and later of the project cash flow based on Year One dollar values that you specify on the System Costs page, Financing page, Utility Rate page, Incentives, or pages.

The default value of 2.5% is based on consumer price index data from the U.S. Department of Labor Bureau of Labor Statistics, and is the average of the annual average consumer price index between 1991 and 2012.

Real Discount Rate

A measure of the time value of money expressed as an annual rate. SAM uses the real discount rate to calculate the present value (value in year one) of dollar amounts in the project cash flow over the analysis period and to calculate annualized costs.

Note. For projects with one of the Utility or Commercial PPA financing options, SAM includes both a discount rate and internal rate of return (IRR) in the analysis. For these projects, the discount rate represents the value of an alternative investment, and the IRR can represent a profit requirement or the risk associated with the project. For example, the IRR may be higher than the discount rate for a renewable energy project with higher risk than an alternative investment.

Nominal Discount Rate

SAM calculates the nominal discount based on the values of the real discount rate and the inflation rate:

Nominal Discount Rate = (1 + Real Discount Rate) × (1 + Inflation Rate) - 1

Tax and Insurance Rates

Federal and State Income Tax Rates

The annual federal and state income tax rate applies to taxable income and is used to calculate tax benefits or liabilities.

For all projects, taxable income includes income from any incentives marked on the Incentives page as taxable.

For residential and commercial projects, SAM does not consider the value of electricity saved by the system to be income. However, for commercial projects, because those savings represent the value of electricity purchases that would have been a tax-deductible operating expense to the commercial entity, SAM does reduce the project after-tax cash flow by the amount of federal and state income tax on the value of the electricity. In other words, with the renewable energy system in place, the commercial entity must pay tax on that portion of its income that it would have deducted as an operating expense.

For commercial PPA and utility IPP projects, the energy value represents electricity sales that are taxable income.

Sales Tax

The sales tax is a one-time tax that SAM includes in the project's total installed cost. SAM calculates the sales tax amount by multiplying the sales tax rate on the Financing page by the rate you specify under Indirect Capital Costs and the Total Direct Cost on the System Costs page.

For tax purposes, because SAM includes the sales tax amount in the total installed cost, it treats sales tax as part of the cost of property. For projects with depreciation (Commercial and Utility financing options only), SAM includes the sales tax amount in the depreciable basis. See IRS Publication 551, Basis of Assets, for more details.

Some states and other jurisdictions offer a sales tax exemption for renewable energy projects. To model a sales tax exemption in SAM, reduce the sales tax percentage as appropriate. For example, for a 100% sales tax exemption, enter a sales tax rate of zero.

For projects with debt, because SAM includes the sales tax amount in the total installed cost, the sales tax influences the debt amount and debt interest payment. For projects where debt interest payments are deductible from federal and state income tax (all financing options except Residential with standard loan), SAM includes sales tax in the calculation of the deductions.

Insurance Rate (Annual)

The annual insurance rate applies to the total installed cost of the project. SAM treats insurance as an operating cost for each year. The insurance cost in year one of the project cash flow is the insurance rate multiplied by the total installed cost from the System Costs page. The first year cost is then increased by inflation in each subsequent year. For commercial and utility projects, the insurance cost is an operating expense and therefore reduces federal and state taxable income.

Property Tax

Property tax is an annual project expense that SAM includes under Operating Expenses in the cash flow.

SAM treats property tax as a tax-deductible operating expense for each year. In each year of the project cash flow, the property tax cost is the property tax rate multiplied by the assessed value for that year.

SAM determines the annual property tax payment by calculating an assessed value for each year in the cash flow, and applying the assessed percent to that value. The assessed value may decline from year to year at the rate you specify. The assessed percent and tax rate both remain constant from year to year.

For residential projects, the property tax amount is the only operating cost that can be deducted from state and federal income tax.

Note. For the residential and commercial financing option, SAM calculates a real estate value added amount for each year in the analysis period. SAM does not use the value to calculate property tax, or to calculate financial metrics such as LCOE or NPV. You can find the value on the Results page Tables under **Annual Data**.

Assessed Percent

The assessed value of property subject to property taxes as a percentage of the system total installed cost specified on the System Costs page. SAM uses this value to calculate the assessed property value in year one of the project cash flow.

Assessed Value

The assessed property value in Year One of the project cash flow:

Assessed Value ($) = Assessed Percent (%) × Total Installed Cost ($)

Where Total Installed Cost is from the System Costs page.

Assessed Value Decline

The annual decline in the assessed property value. SAM uses this value to calculate the property assessed value in years two and later of the project cash flow. For an assessed value that does not decrease annually, specify a value of zero percent per year.

Property Tax

The annual property tax rate applies to the assessed value of the project in each year of the project cash flow.

Salvage Value

SAM considers the salvage value to be project income in the final year of the project cash flow, and calculates the value as a percentage of the total installed cost from the System Costs page.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period. SAM reports the salvage value amount in the final year of the project cash flow under

Operating Expenses.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

For residential projects, the salvage value has no effect on federal and state income tax.

For commercial and utility projects, the salvage value is treated as a source of pre-tax revenue in the final year of the analysis period, increasing the federal and state taxable income.

Net Salvage Value

The salvage value as a percentage of the project's total installed cost from the System Costs page.

End of Analysis Period Salvage Value

The salvage value dollar amount that will appear in final year of the project cash flow.

End of Analysis Period Salvage Value ($) = Net Salvage Value (%) × Total Installed Cost ($)

Where *Total Installed Cost* is from the System Costs page.

Construction Financing

SAM allows you to specify parameters for up to five construction loans to approximate interest during construction (IDC) that SAM considers to be a cost to the project.

SAM assumes that 100% of the construction balance is outstanding for half of the construction period, which is equivalent to an even monthly draw schedule with an average loan life of half of the construction period. To approximate a different draw schedule, you could adjust the loan's interest rate accordingly.

Note. To model a project with no construction period loans, set the **Percent of Installed Costs** value for each of the five loans to zero.

For the Commercial PPA and Independent Power Producer options, SAM includes the total construction financing cost in the project loan principal amount shown on the Financing page.

For the partnership flip, sale leaseback, and single owner options, SAM includes the total construction financing cost in the Financing Cost reported in the Metrics table. The financing cost, in turn, is part of issuance of equity value reported in the project cash flow.

Construction Loans

SAM allows you to specify up to five construction loans. You can type a name describing each loan or use the default names.

Percent of Installed Costs

The amount borrowed for the construction loan as a percentage of the total installed cost, assuming that all construction costs are included in the installation costs you specify on the System Costs page. Specify a non-zero percentage for each construction period loan you want to include in the analysis.

The sum of the up to five percentage values you specify for each construction loan must be 100%.

Up-front Fee

A percentage of the principal amount, typically between 1% and 3% that SAM adds to the interest amount for each construction loan to calculate the total construction financing cost. Note that no interest applies to the up-front fee.

Up-front Fee Amount ($) = Principal Amount ($) × Up-front Fee Percentage (%)

Months Prior to Operation

The loan period for the construction loan in months.

Annual Interest Rate

The construction loan interest rate as an annual percentage.

Principal

The amount borrowed for each construction period loan:

Principal Amount ($) = Total Installed Cost ($) × Percent of Installed Costs (%)

Interest

The total interest payment due for each construction period loan, assuming that 100% of the construction balance is outstanding for half of the construction period.

Interest ($) = Principal Amount ($) × Loan Rate (%/yr) / 12 (mos/yr) × 0.5

Total Construction Financing Cost

SAM includes the total construction financing cost in the project cost.

Total Construction Financing Cost = Interest + Up-front Fee Amount

Cost of Acquiring Financing

The Cost of Acquiring Financing input values represent the cost of securing debt or the participation of tax investors.

Financing Cost (Single Owner only)

The dollar amount associated with acquiring financing.

Development Fee (All options except Single Owner)

A fee paid to the developer in Year 0, specified as a percentage of the total installed cost on the System Costs page.

Development Fee ($) = Development Fee (%) × Total Installed Cost ($)

Equity Closing Cost (All options except Single Owner)

A dollar amount representing costs associated with securing participation of a tax investor, such as consultants and legal fees.

Other Financing Costs (All options except Single Owner)

A dollar amount for financing costs not included in the equity closing cost or development fee.

SAM calculates the project's total cost of financing and reports it as the Financing Cost in the Metrics table, which is part of the issuance of equity value reported in the cash flow.

Reserve Accounts

Interest on Reserves

Annual interest rate earned on funds in reserve accounts. The different financing options have different reserve accounts, and the interest on reserves rate applies to all of the accounts available for a given option:

- Working capital reserve account, specified under Cost of Acquiring Financing.

- Major equipment reserve account, specified under Major Equipment Replacement Reserves.
- Debt service reserve account (Leveraged Partnership Flip, Single Owner), specified under Debt Service.
- Lessee reserve account (Sale Leaseback), specified under Sale Leaseback.

Working Capital Reserve Account

The size of the working capital reserve in months of operation.

Working Capital Reserve Amount = Months of Operating Costs (months) / 12 months/yr × Year One Total Expenses ($/yr)

Debt Service Reserve Account

A debt service reserve account is a fund that may be required by the project debt provider. The account is funded in Year 0 and earns interest in Years 1 and later at the reserve interest rate specified under Reserves. Once debt has been repaid, the funds in the account are released to the project cash flow.

The number of months of principal and interest payments in Year One whose value is equivalent to the size of the debt reserve account in Year 0.

SAM calculates the reserve account size in Year 0 based on the principal and interest amounts in Year One:

Year 0 Debt Service Reserve Amount = (Year One Principal ($/yr) + Year One Interest ($/yr)) × Debt Service Reserve Account (months) / 12 (months/yr)

Tip. Debt Service Reserve Accounts for utility-scale projects are typically sized to cover 6 to 12 months of principal and interest payments.

Major Equipment Replacement Reserve Accounts

Major equipment replacement reserves are funds that the project sets aside to cover the cost of replacing equipment during the analysis period. You can specify up to three replacement reserve accounts.

SAM assumes that the cost of each major equipment replacement is capitalized rather than expensed. You can specify a depreciation schedule for each the major equipment replacement cost.

SAM calculates the inflation-adjusted cost of each major equipment replacement and funds a reserve account in each of the replacement cycle. At the time of the major equipment replacement, funds are released from the reserve account in an amount sufficient to cover the expense.

Account Name

The name of the reserve account for your reference. SAM reports value associated with each account in the cash flow and other graphs and tables using the name Reserve Account 1, 2, and 3, regardless of the name you enter.

Replacement Cost

The cost in Year One dollars per kW of nameplate capacity.

Replacement Cost ($) = Replacement Cost (Year One $/kW) × Nameplate Capacity (kW)

Replacement Frequency

The frequency in years that the replacement cost occurs.

For example, a replacement cost of $10,000 and frequency of 5 years results in an inflation-adjusted major equipment capital spending amount of $10,000 occurring in Years 5, 10, 15, 20, etc.

Depreciation Treatment For All Capital Expenditure

Specify a federal and state depreciation method for the major equipment replacement cost.

SAM includes major equipment replacement reserves in the annual total depreciation amount in the cash flow.

13.10 Time of Delivery Factors

The Time of Delivery Factors page allows you to specify a set of time-of-delivery (TOD) factors to model time-dependent pricing for projects with one of the Utility Financing options.

> **Note.** For the CSP technologies, the TOD factors appear on the Thermal Energy Storage page.

The TOD factors are a set of multipliers that SAM uses to adjust the PPA price based on time of day and month of year for utility projects. The factors work in conjunction with the assumptions on the Financing page.

For a description of TOD-related simulation results, see Savings and Revenue.

Energy Dispatch Schedule

You can either choose a pre-defined set of TOD factors from SAM's library of factors, or specify your own.

Current dispatch schedule

When you choose a set of factors from the library, the current dispatch schedule shows the name of the set of factors.

When you specify your own set of factors, it shows "No library match."

Dispatch schedule library

Click **Dispatch schedule library** to choose a set of TOD factors from SAM's library of factors.

TOD Factor

The TOD factors are a set of up to nine multipliers that SAM uses to adjust the electricity price based on time of day and month of year for utility projects. Each factor is associated with a period number, which represents a time periods indicated on the weekday and weekend schedule matrices.

> **Note.** For utility bid price projects with no TOD factors, set the value for all periods to one.

Weekday Schedule, Weekend Schedule

The weekday and weekend matrices allow you to associate a period with a time of day and month of year. To use the matrices, you draw rectangles on the matrix with your mouse, and type a number with your keyboard for the period that applies to the times represented by the rectangles.

SAM arbitrarily defines the first day of time series data (the first 24 hours for hourly data) to be Monday on January 1, and assigns the remaining days of the year accordingly. SAM assumes that weekdays include Monday through Friday, and that weekends include Saturday and Sunday. SAM does not account for holidays or other special days. It also does not account for leap years, and does not include a day for February 29.

To specify a weekday or weekend schedule:

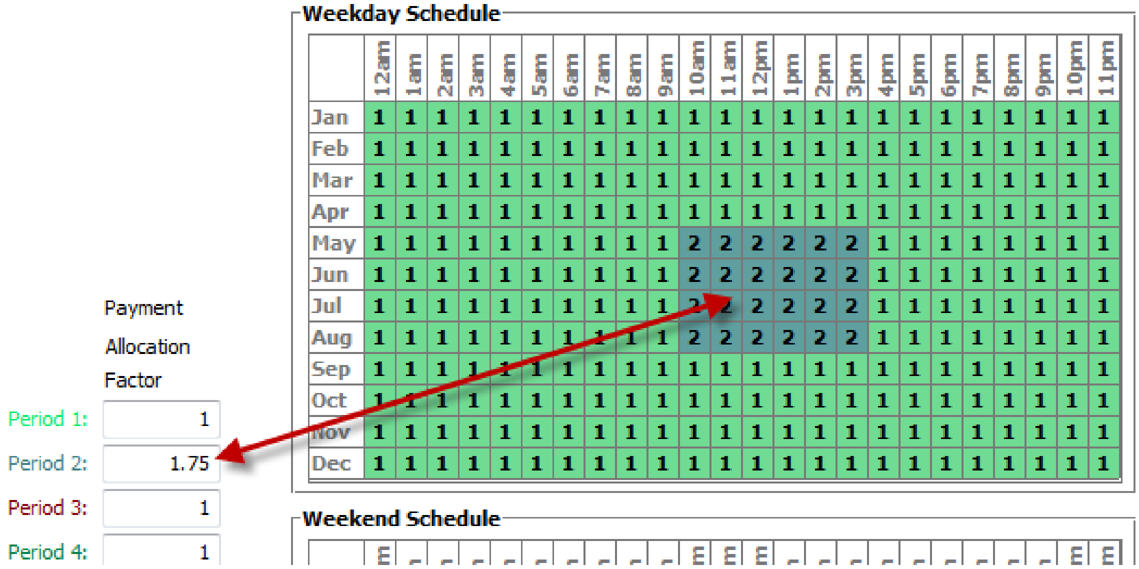
1. Assign values as appropriate to each of the up to nine periods.
2. Use your mouse to draw a rectangle in the matrix for the first block of time that applies to period 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

3. Type the number 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

4. SAM shades displays the period number in the squares that make up the rectangle, and shades the rectangle to match the color of the period.



5. Repeat Steps 2-4 for each of the remaining periods that apply to the schedule.

13.11 Incentives

To view the Incentives page, click **Incentives** in the main windows navigation menu.

The Incentives page allows you to define the parameters for the following types of tax credits and cash incentives.

A tax credit is an amount that is deducted from the project's income tax:

- Investment tax credits (ITC)
- Production tax credits (PTC)

A cash incentive is an amount paid to the project that contribute's to the projects annual income in one or more years of the cash flow:

- Investment-based incentive (IBI)
- Capacity-based incentive (CBI)
- Production-based incentive (PBI)

You can either specify the incentives by hand, or, for locations in the United States, you can download CBI, PBI, and ITC incentive data from the Database of State Incentives for Renewables and Efficiency at http://dsireusa.org.

After running simulations, you can display incentive amounts in the project cash flow and in results graphs and tables.

> **Note.** You can also model projects that qualify for an accelerated depreciation tax benefit using options on the Depreciation page.

DSIRE Online Incentives Database

SAM can download incentive data for locations in the United States from the Database of State Incentives for Renewables and Efficiency at http://dsireusa.org.

SAM uses the latitude and longitude data from your weather file to determine the location for the connection with the DSIRE database, and the financing option (residential, commercial, utility) for the current case to determine which incentives to include in the download list.

To download incentives data from DSIRE:

1. Verify that the latitude and longitude in your weather file is correct. SAM displays the values in the Navigation menu.
2. On the Incentives page, click **Download Incentives**.
3. In the list of available incentives, check the box for each incentive that you want to apply to your analysis.

   Click the description of the incentive (not the check box itself) to display more details in the text box below the list.
4. If you do not want SAM to delete values for similar incentives that currently appear on the Incentives page, clear the **Clear all incentives before applying** check box.
5. Click **OK**.
6. Verify all of the values and options on the Incentives page to make sure they represent the set of incentives you want to model.

Notes.

The DSIRE data does not include information about whether cash incentives payments are taxable, or about their effect on the depreciation or ITC basis. Be sure to check the correct boxes after downloading the incentive data.

When you check Clear all incentives before applying, SAM deletes data for incentives of the same type (CBI, PBI, ITC) that have the same units. For example, if you check the option and download data for the 30% Federal ITC, SAM sets the State ITC percentage to zero, but does not clear any ITCs you may have specified as fixed amounts.

Investment Tax Credit (ITC)

An investment tax credit reduces the project's annual tax liability in Year One of the project cash flow. SAM allows the ITC to be expressed either as a fixed amount or as a percentage of the project's total installed cost with a maximum limit.

Tip. SAM applies the ITC percentage to the total installed cost. If you want to model a situation where the percentage applies to less than the total installed cost, you can either modify the ITC percentage accordingly, or calculate the ITC amount outside of SAM and enter it as a fixed amount. For example, for a project with a $10,000 total installed cost where 95% of those costs are eligible for a 30% ITC, you could either enter an ITC percentage of 95% × 35% = 28.5%, or an ITC amount of 30% × 95% × $10,000 = $2,850.

Amount ($)

The fixed dollar amount of the tax credit. A zero indicates no tax credit. A value of zero indicates no tax credit.

Percentage (%)

The amount of the tax credit expressed as a percentage of the total installed cost displayed on the system costs page. A value of zero indicates no tax credit.

Maximum ($)

The upper limit of the tax credit in dollars. For tax credits with no limits, type the value 1e+099.

Reduces Depreciation Basis

Applies only to commercial and utility projects when one of the depreciation options is active on the Depreciation page.

The check boxes determine whether the basis used to calculate federal depreciation, state depreciation, or both should be reduced by the tax credit amount.

SAM reduces the depreciable base by 50% of the present value of the tax credits over the analysis period defined on the Financing page.

Production Tax Credit (PTC)

A production tax credit reduces the project's annual tax liability in Year One of the cash flow and subsequent years up to and including the year specified in the term variable. The PTC is a dollar amount per kilowatt-hour of annual electric output. If you specify an escalation rate, SAM increases the annual tax credit amount in years 2 and later in the cash flow by a percentage of the previous year's credit amount.

Amount ($/kWh)

The amount of the production tax credit as a function of the system's total electrical output in the first year expressed in dollars per kilowatt-hour of AC output. A zero indicates no tax credit.

Term (years)

The number of years, beginning with year 1 on the project cash flow, that the tax credit applies. For example, a credit with a 10-year term would apply to years 1 through 10 of the project cash flow. A zero indicates no tax credit.

Escalation (%/year)

The annual escalation rate that applies to the tax credit. SAM applies the escalation rate to years 2 and later of the project cash flow. SAM does not apply the inflation rate that you specify on the Financing page to the PTC. For example, for a tax credit with a ten year term and two percent escalation rate, the tax credit in year 2 would be 2% greater than in year 1, and in year 3, 2% greater than in year 2, and so on.

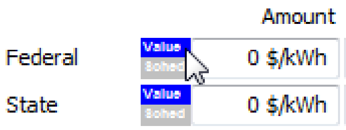
For both the state and federal PTC, SAM rounds the annual PTC rate in cents/kWh to the nearest 0.1 cent as described in Notice 2010-37 of IRS Bulletin 2010-18.

Specifying Year-by-Year PTC Values

You can specify each PTC as either a single value (amount or percentage) that applies to all years in the analysis period defined on the Financing page, or you can assign a different value to each year in the analysis period using an annual schedule.

> **Note.** Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation or escalation rates to values in annual schedules.

By default, you enter the PTC as a single value. The blue "Value" label on the blue and gray button next to the input variable indicates the single value mode is active for the variable.



To specify a PTC using an annual schedule:

1. Click the blue and gray button next to the input variable button to change the mode to **Sched** and activate the Edit button. The button will show "Sched" in blue to indicate that the schedule mode is active for the variable.

2. Click **Edit**.
3. In the Edit Schedule window, type values for each year in the analysis period. Use the vertical scroll bar to move through the years.

   SAM ignores any values for years after the end of the analysis period. You can change the value in **# Values** to a number less than or equal to the analysis period to shorten the length of the table.

   To delete a value, select it and press the Delete key on your keyboard.

   You can use the Copy and Paste buttons to copy values from the table to your clipboard, or paste them into the table from the clipboard.

> **Note.** You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. For years with no PTC type a zero.

4. When you have finished editing the schedule, click **Accept**.

Investment Based Incentive (IBI)

An investment-based incentive reduces the project's annual expenditures in Year One of the project cash flow. SAM allows the IBI to be expressed either as a fixed amount or as a percentage of the project's total installed cost with a maximum limit.

Note that if you specify two incentives from the same source (federal, state, utility, other) as both a fixed amount and a percentage of the total installed cost, SAM includes both amounts in the total incentive amount.

Amount ($)

The fixed dollar amount of the incentive. A zero indicates no incentive.

Percentage (%)

The amount of the investment tax credit expressed as a percentage of the total installed cost displayed on the system costs page. A zero indicates no incentive.

Maximum ($)

The upper limit of the incentive in dollars. For incentives with no limits, type the value 1e+099.

Capacity Based Incentive (CBI)

A capacity-based incentive reduces the project's annual expenditures in Year One of the project cash flow. SAM allows the CBI to be expressed as a function of the system's rated capacity in watts. The system's rated capacity depends on the technology:

- Photovoltaic systems: DC watts of array capacity.
- Concentrating solar power systems: AC watts of power block nameplate capacity.
- Generic fossil: AC watts of power block nameplate capacity.

Check an option for each capacity based incentive that applies to the project, and enter values to specify the credit amount, percentage, term, and annual escalation rate as applicable.

Amount ($/W)

The amount of the incentive as a function of the system's nameplate electric capacity expressed in dollars per watt. A zero indicates no incentive.

Maximum ($)

The upper limit of the incentive in dollars. For incentives with no limits, type the value 1e+099.

Production Based Incentive (PBI)

A production-based incentive reduces the project's annual tax liability in Year One of the cash flow and subsequent years up to and including the year specified in the term variable. The PBI is a dollar amount per kilowatt-hour of annual electric output. If you specify an escalation rate, SAM increases the annual incentive payment in years two and later in the cash flow by a percentage of the previous year's payment.

Note. For the Single Owner and Leveraged Partnership Flip financing options, you can specify whether the PBI payments are available for debt service.

Amount ($/kWh)

The amount of the incentive as a function of the system's total electrical output in the first year expressed in dollars per kilowatt-hour of AC output. A zero indicates no incentive.

Term (years)

The number of years, beginning with Year One of the project cash flow, that the incentive applies. For example, an incentive with a 10-year term would apply to years one through 10 of the project cash flow. A zero indicates no incentive.

Escalation (%/year)

The annual escalation rate that applies to the incentive. SAM applies the escalation rate to years two and later in the cash flow. For example, for an incentive with a ten year term and two percent escalation rate, the incentive in year two would be two percent greater than in Year One, and in year three, two percent greater than in year two, and so on.

Note. If you use an annual schedule to assign PBI amounts to specific years, SAM ignores the escalation rate.

Tax Implications

The check boxes in the Taxable Incentive, Reduces ITC Basis, and Reduces Depreciation Basis columns determine whether each incentive qualifies as income for tax purposes, reduces the basis used to calculate the ITC, or reduces the basis used to calculate the depreciation amount, respectively.

Taxable Incentive

Determines whether the incentive payment is subject to federal or state income tax.

When you check a Taxable Incentives check box for an incentive, SAM multiplies the applicable federal and state tax rate by the incentive amount and adds it to the income tax amount in the appropriate years of the project cash flow.

The state and federal tax rates are inputs on the Financing page.

Reduces Depreciation and ITC Bases

Determines whether the incentive reduces the basis used to calculate depreciation for projects with Commercial or Utility financing, and whether it reduces the basis used to calculate the ITC amount for projects with an investment tax credit.

The options apply to projects with any of the following:

- Commercial financing
- Utility financing
- One or more ITCs specified on the Tax Incentives page.

When you check **Reduces Depreciation and ITC Bases** for an incentive, SAM does one or both of the following:

- Subtract the amount of the incentive or tax credit amount from the total installed cost shown on the system costs page before calculating the ITC amount.
- SAM subtract 50 percent of the incentive or tax credit amount from the depreciation basis in each applicable year of the project life.

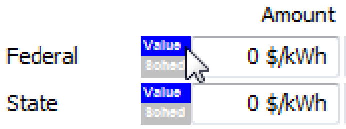
Note. You can see the depreciation and ITC amounts in the project cash flow.

Specifying Year-by-Year Values for PBI Values

You can specify each PBI as either a single value (amount or percentage) that applies to all years in the analysis period defined on the Financing page, or you can assign a different value to each year in the analysis period using an annual schedule.

Note. Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

By default, you enter the PBI as a single value. The blue "Value" label on the blue and gray button next to the input variable indicates the single value mode is active for the variable.



To specify a PTC using an annual schedule:

1. Click the blue and gray button next to the input variable button to change the mode to **Sched** and activate the Edit button. The button will show "Sched" in blue to indicate that the schedule mode is active for the variable.

2. Click **Edit**.
3. In the Edit Schedule window, type values for each year in the analysis period. Use the vertical scroll bar to move through the years.

   SAM ignores any values for years after the end of the analysis period. You can change the value in **# Values** to a number less than or equal to the analysis period to shorten the length of the table.
4. To delete a value, select it and press the Delete key on your keyboard.
5. You can use the Copy and Paste buttons to copy values from the table to your clipboard, or paste them into the table from the clipboard.

> **Note.** You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. For years with no PBI type a zero.

6. When you have finished editing the schedule, click **Accept**.

13.12 Depreciation

To view the Depreciation page, click **Depreciation** in the main windows navigation menu.

> **Note.** The Depreciation page is not available for the Residential financing option.

Depreciation for Utility IPP and Commercial PPA Projects

The depreciation inputs represent the decrease in value of project assets over the analysis period. Depreciation reduces federal and state taxable income, shown under *Tax Effect on Equity* in the project cash flow.

For the Commercial, Commercial PPA, and Utility IPP financing options, SAM assumes that the depreciation method you choose applies to the entire depreciable basis. For these projects, the depreciable basis in each year of the project cash flow is the total installed cost less any incentives you specify as reducing the depreciation basis on the Incentives page:

Depreciable Basis = Total Installed Cost + Total Construction Financing Cost - (Total ITC × 0.5 + Total IBI + Total CBI + Total PBI)

Where *Total Installed Cost* is from the System Costs page, and *ITC* includes all tax credits that you specified on the Incentives page to reduce the depreciation basis, and *IBI*, *CBI*, and *PBI* include all incentives you specified to reduce the depreciation basis.

Notes.

After running simulations, you can verify the depreciation percentages and amounts in the cash flow in the rows under Tax Effect on Equity.

The advanced utility financing options (available only for projects that sell power through a power purchase agreement) allow you to allocate portions of the depreciable basis to different depreciation classes. If you are modeling a project with the Utility IPP option, and would like to allocate depreciation to different classes, you can change the financing option on the Technology and Market window to **Advanced Utility IPP Options**, **Single Owner**.

No Depreciation

The project does not claim a depreciation tax deduction.

5-yr MACRS

Modified Accelerated Cost Recovery System depreciation schedule offered by the Federal government and some states using a five-year life and half-year convention.

This tax deduction, expressed as a percentage of the depreciable basis, applies to the first five years of the project life as follows: 20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76%.

Straight Line (specify years)

A depreciation schedule offered by the Federal government and some states.

SAM calculates the depreciation percentage for the straight line depreciation option by dividing the analysis period by the number of years:

SL Depreciation Percentage = Analysis Period (years) ÷ SL Number of Years (years) × 100%

Custom (specify percentages)

Allows you to assign a depreciation deduction as a percentage of the total installed cost for each year in the project life.

To specify a custom depreciation schedule, click **Custom (specify percentages)**, and then click **Edit** to open the Edit Schedule Window. Each row in the table represents a year in the analysis period. For **# Values**, type a number equal to or greater than the analysis period. (SAM ignores any values you enter for years after the analysis period.) For each year in the table, type a percentage. SAM will calculate the depreciation amount for each year in the cash flow by multiplying the percentage you specify for that year by the depreciable basis described above.

Depreciation for Single Owner, Partnership Flip, and Sale Leaseback Projects

The Depreciation options allow you to specify how SAM calculates the depreciation tax deduction and to specify an optional bonus depreciation.

SAM makes the following simplifying assumptions:

- To represent depreciation of assets with different classes or service lives, you can specify an allocation as a percentage of the total installed cost to each of up to six different depreciation methods.
- State and federal depreciable bases are the same, except for bonus depreciation.

- Investment-based incentives (IBI) and capacity-based incentives (CBI) reduce the depreciation basis proportionally.

Depreciation Classes

Each row in the Depreciation Classes box represents a recovery period (5, 15, 20, or 39 years) and depreciation method (MACRS or Straight Line) based on the guidelines in the United States tax code. See U.S. Internal Revenue Service Publication 946 (http://www.irs.gov/pub/irs-pdf/p946.pdf) for details.

The following table shows the depreciation percentage by year for each depreciation class:

Years 1-10	1	2	3	4	5	6	7	8	9	10
5-yr MACRS	20.0	32.0	19.2	11.5	11.5	5.8				
15-yr MACRS	5.0	9.5	8.6	7.7	6.9	6.2	5.9	5.9	5.9	5.9
5-yr SL	10.0	20.0	20.0	20.0	20.0	10.0				
15-yr SL	3.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
20-yr SL	2.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	1.3	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 11-20	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
15-yr MACRS	5.9	5.9	5.9	5.9	5.9	3.0				
15-yr SL	6.7	6.7	6.7	6.7	6.7	3.3				
20-yr SL	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 21-30	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
20-yr SL	2.5									
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 31-40	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	1.3

Each depreciation class has an associated value or set of check boxes listed under Federal and State Allocations, Bonus Depreciation, and ITC Qualification.

Custom Depreciation Schedules

For projects outside of the U.S., or for analyses involving depreciation methods other than IRS methods, you can specify a custom depreciation schedule. To specify a custom depreciation schedule, click **Edit**, and enter a percentage for each year in the depreciation schedule table. (Enter values in the table as percentages, not decimals: For example type '25' for 25%.)

Federal and State Allocations

For each depreciation class, specify an allocation. SAM assumes that the same depreciation method and allocations apply to both federal and state taxes.

SAM assumes the half-year convention for all depreciation methods.

To model a project with no depreciation, enter zero for all depreciation methods.

> **Note.** SAM does not prevent you from specifying allocations that total more than 100%. A negative **Non-depreciable** value indicates total allocations greater than 100%. Be sure to check that the non-depreciable value is not negative.

Bonus Depreciation

The bonus depreciation applies in Year One as a percentage of the allocations that you specify for the standard depreciation.

Specify a percentage and check the box for each depreciation allocation that qualifies for the bonus depreciation.

For example, for a federal bonus depreciation that is 100% of the 5 yr MACRS depreciation class, if you specified the following depreciation allocations: 80% 5 yr MACRS, 1.5% 15 yr MACRS, and 3% 15 yr Straight Line, you would enter 100% for **Federal**, check the **5-yr MACRS** box, and clear the remaining boxes.

Tip. The Tax Relief, Unemployment Insurance Reauthorization, and Jobs Creation Act of 2010 extended the bonus depreciation incentive through 2010. Projects placed in service in 2011 qualify for 100% bonus depreciation, while projects placed in service in 2012 qualify for 50% bonus depreciation. Note that these bonus depreciation provisions are temporary.

ITC Qualification

Check the box for each depreciation allocation that qualifies for investment tax credits (ITC) specified on the Depreciation page.

14 Retail Electricity Rates

The retail electricity rates input pages are available when you choose either the Residential or Commercial financing option on the Technology and Market window.

For a description of retail electricity rates, see Retail Electricity Rates Overview.

For a description of results for simulations with time-dependent pricing, see Retail Electricity Savings.

The input pages are:

- Utility Rate
- Electric Load

14.1 Rates Overview

For projects with residential and commercial financing, you specify electricity prices on the Utility Rate page and an electric load on the Electric Load page. The electricity prices are retail prices set by the electric service provider.

Notes.

SAM can download utility rate data from the [OpenEI Electric Utility Rates] database. See [Utility Rate] page for details.

To familiarize yourself with how SAM models electric rate structures, see the *Residential Net Metering and Tiered TOU Examples* sample file (click **File**, **Open sample file**).

You can specify an electric rate structure with any level of complexity, from a simple flat rate to a complex schedule with time-of-use rates that change with time, demand charges, and tiered rates with our without net metering:

- Fixed energy rate: A fixed buy or sell rate in dollars per kilowatt-hour that does not vary with time or with the amount of electricity the project purchases.
- Net metering: The project purchases electricity at either a fixed or tiered time-of-use buy rate, and receives a monthly credit for each month that the electricity generated by the system exceeds the total monthly electricity load. That credit is applied to the next month's electricity purchases. Any credit that remains at the end of the year is paid to the project at the year end sell rate.
- Fixed monthly charge: A fixed amount in dollars that the project pays at the end of each month.
- Time-of-use rate: Rates in dollars per kilowatt-hour that vary with time of day and month of year.
- Demand charges: Monthly fees in dollars per kilowatt paid by the project for the maximum monthly electric demand. You can specify demand charges as fixed monthly charges or as charges that vary with time of use.
- Tiered rates and charges: Rate and charges that vary with the amount of electricity purchased by the project over a period of time.

You can also specify an escalation rate if you expect electricity prices to increase from year to year at a rate above inflation.

SAM reports the time-dependent pricing data on the Results page after you run simulations. For details, see Retail Electricity Savings.

Note that the electricity buy and sell rates do not affect the project's levelized cost of energy (LCOE), because for residential and commercial projects, SAM calculates the LCOE based on the project after-tax cash flow, which does not include the value of electricity saved by the system. The electricity rates do affect the project net present value and payback period.

The input pages are:

- Utility Rate
- Electric Load

14.2 Utility Rate

To view the Utility Rate page, open a case with either the residential or commercial financing option, and then click **Utility Rate** in the main window's navigation menu.

The Utility Rate page allows you to specify a rate schedule for residential and commercial projects. The rate schedule defines the prices of electricity purchased and sold by the project under an agreement with an electric service provider. For some service providers in the United States, you can download the rate structure from the internet.

For a description of retail electricity rates, see Retail Electricity Rates Overview.

For a description of where to find simulation results for analyses that involve time-dependent power pricing, see Retail Electricity Savings.

Notes.

The Utility Rate page is available only for the residential and commercial financial models. For the utility or commercial PPA financial models, the electricity sales price is an input on the Financing page, or it may be a result that SAM calculates. See Financing Overview for a description of the different financial models.

When you specify time-of-use rates, demand charges, or tiered rates, you must also specify a building or facility electric load on the Electric Load page. If you do not specify a load, all of the electricity generated by the system is sold at the price that applies in each hour.

The Utility Rate page in the current version of SAM is substantially reorganized from SAM 2013.1.15 and accesses a different (updated) database of utility rates from the OpenEI Utility Rate Database.

To familiarize yourself with how SAM models electric rate structures, see the *Residential Net Metering and Tiered TOU Examples* sample file (click **File**, **Open sample file**).

Contents

- Input Variable Reference describes each of the input variables on the Utility Rate page.
- Importing Rate Structure Data explains how to download rate structure data from NREL's OpenEI database.
- Defining Weekday and Weekend Schedules explains how to use the Weekend and Weekday matrices to define the times when charges apply.

Input Variable Reference

OpenEI Online Utility Rate Database

NREL's Open Energy Information (OpenEI) Utility Rate Database hosts a database of electricity rate structures for a selection of U.S. electric service providers. SAM allows you to search the database and import rate structure data from the database to the input variables on the Utility Rate page.

Search for Rates

Search the OpenEI database for a rate structure and import the structure into SAM. This feature requires a web connection. See Importing Rate Structure Data for details.

Go to website

Open the OpenEI website (http://en.openei.org/wiki/Gateway:Utilities) in your computer's default Web browser.

Notes.

SAM does not use location information from the Location and Resource page to determine the utility service provider for your analysis. You can import a rate structure for any utility in the OpenEI utility rate database.

When you import data from the OpenEI database, SAM imports the appropriate rates and schedule data, but may not check the boxes to enable the rate options that apply to the rate structure. After importing a rate structure, be sure to enable the appropriate options.

In some cases, the data in the OpenEI database may be incorrect. Be sure to compare the data you import to the information on the utility service provider's rate sheet. You can provide feedback to the database team: Join the database community at http://en.openei.org/community/group/utility-rate or email the database team.

Description

These variables help you identify the rate structure. These are optional variables and do not affect SAM results. If you download rate structure data from the internet, SAM populates the variables automatically.

Name

The name or title of the rate structure.

Description

Text describing the rate structure.

Schedule

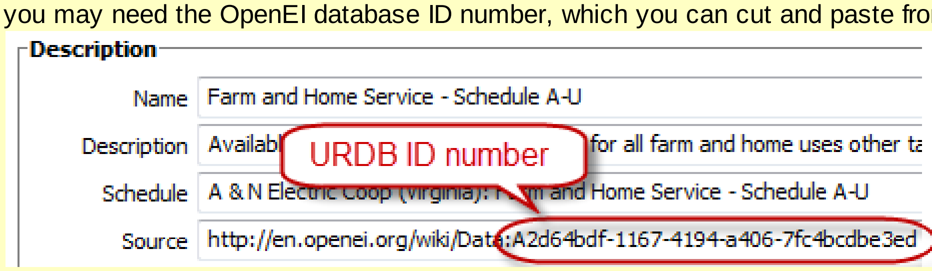
The schedule name, often an alphanumeric designation used by the electric service provider.

Source

A description of the data source.

If you downloaded the rate structure from the OpenEI database, the source is a web link to the rate's entry page on the OpenEI website where you can find a link to the original source document. You can use your mouse to select and copy the link and paste it into your web browser.

Note. If you are working with the sample file *SamUL Cost Savings with Different Rate Structures.zsam*, you may need the OpenEI database ID number, which you can cut and paste from the URL:



Fixed Energy Rates

The fixed energy rates are dollar-per-kilowatt-hour rates that do not vary with the quantity of electricity purchased or sold by the project. You can use these values for a simple rate structure that consists of one buy rate and one sell rate, or in a more complex rate structure to represent fixed charges that apply in addition to time-of-use and tiered rates.

Notes.

If you specify different fixed buy and sell rates, you should also specify load data on the Electric Load page. SAM compares the renewable energy system's output to the load data in each hour to determine whether to buy or sell electricity in that hour.

If you specify both a flat rate and time-of-use and tiered rates, SAM adds all of the rates that apply in a given hour calculate the electricity rate in that hour.

Flat Buy Rate

A fixed energy charge in dollars per kilowatt-hour that the project pays for electricity to meet the load during hours that the renewable energy system's output is less than the electric load.

Flat Sell Rate

The price in dollars per kilowatt-hour paid by the electric service provider to the project during hours that the renewable energy system's output is greater than the electric load.

If you check **Enable net metering**, SAM disables sell rate variable.

Net Metering

With net metering, there is no sell rate. Rather than selling electricity generated by the renewable energy system, the project purchases electricity at either a fixed or tiered time-of-use rate, and receives a monthly credit for each month that the electricity generated by the system exceeds the total monthly electricity usage defined on the Electric Load page. That credit is applied to the next month's electricity purchases. Any credit that remains at the end of the year is paid to the project at the **Year End Sell Rate**.

Notes.

A rate structure with net metering can use either a flat buy rate (under **Fixed Energy Rates**) or time-dependent buy rates (under **Time-of-use and Tiered Energy Charges**), or both.

If you imported a rate structure with net metering from the OpenEI Utility Rate Database, the Enable net metering check box may not automatically be checked. This is a known issue with the OpenEI database that the database team is working to resolve (as of 9/18/2013).

Enable net metering

Check the box if net metering applies to your rate structure. Checking the box disables all of the Sell Rate input variables in the rate structure.

Year End Sell Rate

The rate at which the electric service provider purchases any credits that remain at the end of the year. SAM assumes that the payment to the project occurs on December 31st.

Monthly Charge

A fixed charge is a fee that the project pays to the electric service provider that does not depend on the quantity of electricity consumed or generated by the project.

Fixed Monthly Charge

A fixed dollar amount that applies to all months.

Because SAM tracks project sales and purchases on an hourly basis, it assigns the monthly fixed charge to the last hour (hour ending at 12:00 am of the following day) of each month:

Date	Hour
Jan 31	744
Feb 28	1416
Mar 31	2160
Apr 30	2880
May 31	3624
Jun 30	4344
Jul 31	5088
Aug 31	5832
Sep 30	6552
Oct 31	7296
Nov 30	8016
Dec 31	8760

Annual Escalation

The escalation rate is an annual percentage increase that applies to all of the rates and charges that you specify on the Utility Rates page.

Out-year escalation

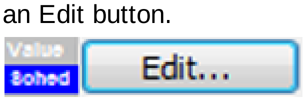
The annual escalation rate to calculate electricity sales and purchases in years 2 and later of the project cash flow.

By default, the escalation rate is a single value that applies in addition to the inflation rate from the Financing page. If you specify an escalation rate of zero, then SAM will use only the inflation rate to calculate out-year sale and purchase values.

In some cases, it may be appropriate to use an annual schedule to define a different escalation rate for each year. When you specify the escalation rate using an annual schedule, SAM applies only the escalation rate and excludes inflation from the calculation of out-year values.

To specify annual escalation rates (optional):

1. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.



2. Click **Edit**.

3. In the Edit Schedule window, type the escalation rate that applies for each year. By default the list shows 50 values. You can change it to the **Analysis Period** from the Financing page by changing the number in **# Values**.

   To delete a value, select it and press the Delete key on your keyboard.

Note. You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no escalation rate.

Time-of-use and Tiered Energy Rates

The tiered and time-of-use energy rates are rates that vary with the time of day, month of year, or both. The energy charges may also vary with the electric load over one ore more periods.

Notes.

If you specify time-of-use or tiered rates, you should also specify load data on the Electric Load page. SAM compares the renewable energy system's output to the load data in each hour to determine whether to buy or sell electricity in that hour.

If you specify both a flat rate and tiered time-of-use rates, SAM adds the two rates to calculate the rate in each hour.

Enable time-of-use and tiered energy rates

Check the box to apply the tiered time-of-use rate schedule. Clear the box to disable the schedule without losing the data.

Weekday

The time-of-day and month-of-year matrix that assigns a period representing set of time-of-use rates to the five working days of the week: Monday through Friday. SAM assumes that the year begins on Monday, January 1, in the hour ending at 1:00 am.

Weekend

The time-of-day and month-of-year matrix that assigns time-of-use periods to the two weekend days of the week: Saturday and Sunday.

Period 1-12

The buy and sell rates in dollars per kilowatt-hour for each of up to twelve periods. Assign a period number to the Weekday or Weekend matrices by using your mouse to select a block in the matrix and typing the period number on your keyboard. Type the letters a, b, or c for the period numbers 10, 11, and 12, respectively.

For a rate structure with net metering, each period typically represents one or more entire months. For a rate structure with no net metering and time-of-use rates, the periods typically represent hours during peak, off-peak, and shoulder periods.

Tier 1-6

For each period, you can define up to six tiers. Each tier is defined by a maximum usage, buy rate, and sell rate, described below.

If your rate structure has time-of-use rates but does not have tiered rates, use Tier 1 to define the buy and sell rates for each period, and ignore Tiers 2-6. Set the Tier 1 maximum usage to 1e+099, which is a very large number equivalent to no limit.

Max Usage kWh

For rate structures with tiered rates, **Max Usage** is an upper limit that applies to each tier.

For a rate structure with tiered rates and net metering, Max Usage is the maximum quantity of electricity in a month for which the tier's rates apply. For example, for a three-tier structure with one buy rate for electricity purchased up to 500 kWh, a second price for electricity purchased over 500 kWh and up to 800 kWh, and a third price for any electricity purchased in excess of 800 kWh, you would specify **Max Usage** for Tier 1 at 500 kWh, Tier 2 at 800 kWh, and Tier 3 at 1e+099.

For a rate structure with tiered rates and no net metering, Max Usage is the maximum quantity of electricity in *each hour* that the tier's rates apply.

Buy Rate $/kWh

The price paid by the project in dollars per kilowatt-hour to purchase electricity from the electric service provider.

Sell Rate $/kWh

The price paid to the project in dollars per kilowatt-hour by the electric service provider for electricity delivered by the project to the grid.

Demand Charge

A demand charge is a fee that the project pays to the electric service provider that depends on the load data you specify on the Electric Load page. The electric demand in a given hour is the difference between the load in that hour and the electricity generated by the system in that hour.

You can use the demand charge inputs to specify a flat demand charge, a tiered demand charge structure, or a time-of-use demand charge structure.

SAM arbitrarily applies the monthly demand charge to the final hour of each month. For example, SAM applies the charge for January to hour 744 (for a month with 31 days, 24 hours/day × 31 days/month = 744 hours/month):

Date	Hour
Jan 31	744
Feb 28	1416
Mar 31	2160
Apr 30	2880
May 31	3624
Jun 30	4344
Jul 31	5088
Aug 31	5832
Sep 30	6552
Oct 31	7296
Nov 30	8016
Dec 31	8760

Enable Demand Charge

Check the box to apply demand charges. You can disable demand charges without losing the rate and schedule data by clearing the check box.

Fixed or Tiered Monthly Demand Charges

For a fixed monthly demand charge, use Tier 1 to specify the peak demand in kW and demand charge in $/kW for each month, and ignore Tiers 2-6. The peak demand for Tiers 2-6 should be 1e+099, a very large number that represents no limit.

For a tiered monthly demand charge, specify a peak demand in kW and demand charge in $/kW for each tier that applies for each month. The peak demand for highest tier and above should 1e+099.

Time-of-use or Tiered Time-of-use Demand Charges

For a demand charge that varies with time of day and year with no tiers, use Tier 1 to specify the peak demand in kW and demand charge in $/kW for each period. Assign a period number to the Weekday or Weekend matrices by using your mouse to select a block in the matrix and typing the period number on your keyboard. Type the letters a, b, or c for the period numbers 10, 11, and 12, respectively. The peak demand for Tiers 2-6 should be 1e+099, a very large number that represents no limit.

For a demand charge that varies with time of day and year with tiers, specify a peak demand in kW and demand charge in $/kW for each tier that applies for each period. The peak demand for highest tier and above should 1e+099. Then assign a period number to the Weekday and Weekend matrices for each period.

Importing Rate Structure Data

If your computer is connected to the internet, you can download rate structure data from the OpenEI Utility Rate Database for a selection of electricity service providers in the United States. You can find out more about the database on the OpenEI website: http://en.openei.org/wiki/Gateway:Utilities.

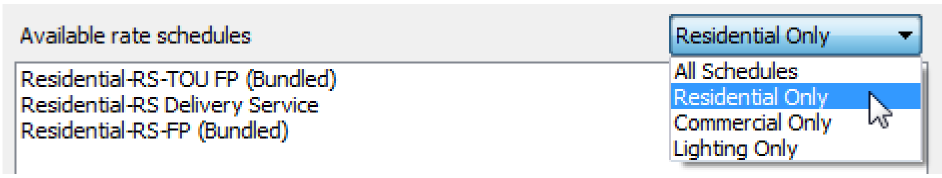
If data for your rate structure or electricity service provider is not available from the OpenEI database, and you have a rate sheet or other documentation of the rate structure, you can add it to the OpenEI database by registering to join the website. You can also enter the rate structure data directly onto SAM's Utility Rate page without using the OpenEI database.

To import rate structure data:

1. On the Utility Rate page, click **Search for rates**. The OpenEI Utility Rate Database Window appears with a list of electric service providers.

   It may take a few moments for the list to appear. If you see a message about not being able to connect to the database, try clicking **Refresh**.
2. After the list appears, locate your electric service provider in the list by either typing some letters from the provider's name in the **Search** box, or by scrolling through the alphabetical list.
3. Click the provider's name to populate the **Available rate schedules** list. If nothing appears in the list, there is no data available for the service provider in the database.

   SAM filters the list to show only rate structures appropriate for the financial model you are using (residential or commercial). You can change the filter to show different rate structures:



4. In the **Available rate schedules** list, click the rate schedule you want to import into SAM. Review the name and description to verify that it is the correct rate structure.

   To see the database entry on the OpenEI website in your web browser, click **Go to rate page on OpenEI.org**. You can also right-click the link to copy the URL to your computer's clipboard.
5. Click **Download and apply utility** rate to download the rate structure data into SAM, or click **Close** to return to the Utility Rate page without downloading the data.

   After you import the data, SAM displays the appropriate rates and schedules on the Utility Rate page.
6. **Important Step!** Verify that the appropriate options for the rate structure are checked: **Enable net metering**, **Enable Energy Charge**, and **Enable Demand Charge**.

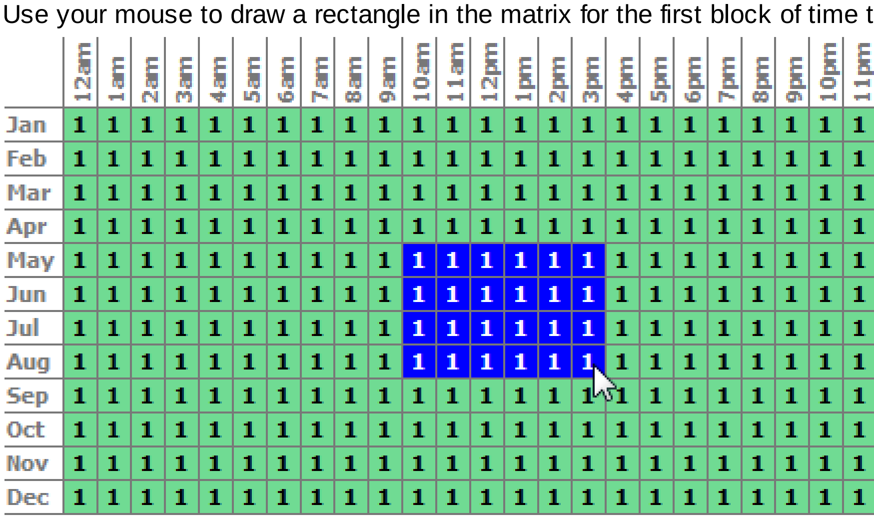
Defining Weekday and Weekend Schedules

The Weekday and Weekend matrices allow you to associate a period with a time of day and month of year. To use the matrices, you draw rectangles on the matrix with your mouse, and type a number with your keyboard for the period that applies to the times represented by the rectangles.

SAM arbitrarily defines the first day of time series data (the first 24 hours for hourly data) to be Monday on January 1, and assigns the remaining days of the year accordingly. SAM assumes that weekdays include Monday through Friday, and that weekends include Saturday and Sunday. SAM does not account for holidays or other special days. It also does not account for leap years, and does not include a day for February 29.

To specify a weekday or weekend schedule:

1. Assign values as appropriate to each of the up to nine periods.
2. Use your mouse to draw a rectangle in the matrix for the first block of time that applies to period 2.



	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

3. Type the number 2.

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

4. SAM shades displays the period number in the squares that make up the rectangle, and shades the rectangle to match the color of the period.

	Buy $/kWh	Sell $/kWh	Adj. $/kWh
Period 1	0.12	0	0
Period 2	0.15	0	0
Period 3	0	0	0
Period 4	0	0	0
Period 5	0	0	0
Period 6	0	0	0
Period 7	0	0	0
Period 8	0	0	0
Period 9	0	0	0

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Feb	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Apr	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
May	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jun	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Jul	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Aug	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1	1
Sep	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Oct	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nov	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dec	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

5. Repeat Steps 2-4 for each of the remaining periods that apply to the schedule.

The following example shows a complete schedule for a TOU rate structure with five periods. In this case, the schedule only uses Periods 1,2 and 4-6.

	Buy $/kWh	Sell $/kWh	Adj. $/kWh
Period 1	0.11458	0	0
Period 2	0.13875	0	0
Period 3	0	0	0
Period 4	0.11556	0	0
Period 5	0.38854	0	0
Period 6	0.18114	0	0
Period 7	0	0	0
Period 8	0	0	0
Period 9	0	0	0

	12am	1am	2am	3am	4am	5am	6am	7am	8am	9am	10am	11am	12pm	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm	10pm	11pm
Jan	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
Feb	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
Mar	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
Apr	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
May	4	4	4	4	4	4	4	4	6	6	6	6	5	5	5	5	5	5	6	6	6	4	4	4
Jun	4	4	4	4	4	4	4	4	6	6	6	6	5	5	5	5	5	5	6	6	6	4	4	4
Jul	4	4	4	4	4	4	4	4	6	6	6	6	5	5	5	5	5	5	6	6	6	4	4	4
Aug	4	4	4	4	4	4	4	4	6	6	6	6	5	5	5	5	5	5	6	6	6	4	4	4
Sep	4	4	4	4	4	4	4	4	6	6	6	6	5	5	5	5	5	5	6	6	6	4	4	4
Oct	4	4	4	4	4	4	4	4	6	6	6	6	5	5	5	5	5	5	6	6	6	4	4	4
Nov	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
Dec	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1

14.3 Electric Load

The Electric Load page allows you to specify the electric load for systems with either the Residential or Commercial financing option. You only need to specify an electric load if you are modeling a residential or commercial system with tiered rates or demand charges specified on the Utility Rate page.

To view the Electric Load page, click **Electric Load** on the main window's navigation menu.

For a description of where to find simulation results for analyses that involve time-dependent power pricing, see Retail Electricity Savings.

Notes.

The NREL OpenEI commercial and residential load profile database is a set of hourly load data files for each of the locations in the NREL National Solar Radiation Database TMY3 weather file collection. To automatically download a load profile from the OpenEI database, see the sample file *SamUL Download Building Load Data* (click **File**, **Open sample file**).

SAM comes with a set of computer-generated residential load data files for some cities in the U.S. See Working with Time Series Load Data for details.

Contents

Overview

The Electric Load page allows you to specify the electric demand, or expected electricity consumption for a grid-connected power system. The load data represents the electric demand of a building or other load center over the period of a single year.

Note. You should only specify electric load data for residential or commercial projects that include demand charges or tiered rates on the Utility Rate page. If your project does not use these rate structures, choose the No load data option on the Electric Load page.

Energy values represent the electric energy required over a single time step and are expressed in kilowatt-hours. Peak load values represent the maximum electric power required in either a month or year and are expressed in kilowatts.

- If you have load data stored in a text file, spreadsheet file, or other file that allows you to copy columns of data to your computer's clipboard, you can paste the data into SAM using the Edit Data window. See Working with Time Series Load Data for details.
- You can also import load data from a properly formatted text file. See Working with Time Series Load Data for details.
- You can specify load data using an hourly time step or sub-hourly time step. The load data time step can be different from the weather data time step. For example, you can use 10-minute load data with hourly weather data. See Working with Time Series Load Data for details.
- If you do not have time series load data, SAM allows you to specify load data by typing a values for twelve monthly 24-hour load profiles. See Creating Load Data from Daily Profiles for details.
- You can scale the load upwards or downwards, or specify a load that increases from year to year. See Input Variable Reference for details.
- SAM displays a load data summary table and allows you to view graphs of hourly load data. See Input Variable Reference for details.
- SAM reports load data in the hourly results. See Tables for details.

Input Variable Reference

Electric Load Data

No load data

Choose **No load data** for an analysis that does not require load data. You should choose this option unless you are modeling a residential or commercial project with time-of-use rates, demand charges, or tiered rates on the Utility Rate page.

Monthly schedule

Choose **Monthly schedule** to specify the load using a set of monthly 24-hour load profiles. See Creating Load Data from Daily Profiles for details.

Edit monthly schedule

Click **Edit monthly schedule** to specify 24-hour load profiles when you chose the monthly schedule option. **Edit monthly schedule** is inactive when you choose **No load data** or **User entered data**.

User entered hourly data

Choose **User entered data** to specify the load by either cutting and pasting load data from an external program, or by importing load data from a properly formatted text file. See Working with Time Series Load Data for details.

Note. You can use this option to work with the sample computer-generated residential load data that comes with SAM.

Edit data

Click **Edit data** to either cut and paste load data from another program or to import data from a properly formatted text file. **Edit data** is inactive when you choose **No load data** or **Monthly schedule**.

Normalize supplied load profile to monthly utility bill data

Check this option when you want to specify the load using monthly data from a utility bill. See Working with Monthly Utility Bill Data for details.

Edit Values

Click **Edit Values** to enter monthly load data from a utility bill. **Edit Values** is inactive unless **Normalize supplied load profile to monthly utility bill data** is checked.

Adjustments

The load adjustment factors allow you to uniformly scale the load up or down, and to model a load profile that increases from year to year. Scaling the load can be useful for scenario analyses where you want to investigate the effect of a higher or lower load than expected loads.

Note. Before using the adjustment factors, you should specify the load data using the monthly schedule or user-entered hourly data options described above.

Escalation

The load escalation scales the load in years two and later by the percentage you specify. For example, if you specify a load escalation rate of 0.5% per year, for each year in the analysis period specified on the Financing page, SAM would increase the load value in each time step by 0.5% of the previous year's load value for the same time step.

You can also assign load escalation values to specific years using the annual schedule:

1. Click the blue and gray button next to the input variable button to change the mode to **Sched** and activate the Edit button. The button will show "Sched" in blue to indicate that the schedule mode is active for the variable.

2. Click **Edit**.
3. In the Edit Schedule window, type values for each year in the analysis period. Use the vertical scroll bar to move through the years.

   SAM ignores any values for years after the end of the analysis period. You can change the value in **# Values** to a number less than or equal to the analysis period to shorten the length of the table.

   To delete a value, select it and press the Delete key on your keyboard.

   You can use the Copy and Paste buttons to copy values from the table to your clipboard, or paste them into the table from the clipboard.

Note. You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. For years with no escalation rate, type a zero.

4. When you have finished editing the schedule, click **Accept**.

Scaling factor

Use the scaling factor to scale up or down the data set you specified using either the monthly schedule or user-entered hourly data option.

When you change the scaling factor value, SAM recalculates the monthly and annual energy and peak values shown on the Electric Load page so you can verify that the value is correct.

To calculate the load value during simulation, SAM multiplies the hourly load data you provided by the scaling factor that you specify. For example, if you specify a scaling factor of 1.5, and the hourly average load at 2 p.m. on March 18th is 1.2 kWh, SAM would use a load value of 1.5 × 1.2 = 1.8 kWh for that hour.

Offset value

To calculate the load value during simulation, for each time step, SAM adds the offset value you specify to the load value. For example, if you specify an offset value of 0.5 kWh, and the hourly average load at 2 p.m. on March 18th is 1.2 kWh, SAM would use a load value of 1.2 + 0.5 = 1.7 kWh for that hour.

To see the effect of the offset value, try changing the value from the default of 1 to another value, and look at how the values under **Hourly Simulation Load Profile Data** change.

Hourly Simulation Load Profile Data

SAM displays the table of monthly and annual averages to help you verify that the load data is correct. SAM also allows you to view also graphs of the time series load data using the built-in data viewer.

Energy (kWh)

The Energy column displays the total amount of electricity required by the load for each month. SAM calculates the value by adding the average hourly values for each month, or if you specify a different time step for the load data, the sum of average values over each time step for the month.

Peak (kW)

The maximum load value that occurs in each month. If you specify hourly load data, the monthly peak is equal to the maximum hourly load value in kWh/h. If you specify sub-hourly load data, the monthly peak is equal to the maximum load value that occurs in the sub-hourly data.

Annual Total

The total amount of electricity required by the load over an entire year. SAM calculates the value by adding the average hourly values for the year, or if you specify a different time step for the load data, the sum of average values over each time step for the year.

The annual total applies to year one of the analysis period. If you specify a load escalation rate under **Adjustments**, the annual total does not reflect load data in years two and later.

Annual Peak

The maximum load value that occurs in the year. If you specify hourly load data, the annual peak is equal to the maximum hourly load value in kWh/h. If you specify sub-hourly load data, the annual peak is equal to the maximum load value that occurs in the sub-hourly data.

Visualize load data

Click Visualize load data to display the time series data in SAM's built-in data viewer.

Calculate Load Profiles

EnergyPlus is a building simulation model developed for the Department of Energy. You can use the EnergyPlus Example File Generator to generate a text file containing hourly load data for different building types and configurations for some locations in the United States. SAM includes a set of residential load profiles created by this web application in the *\samples\Residential Load Data* folder.

The EnergyPlus load data generator uses weather data from the TMY2 data set to generate the load data. If you model a system in SAM using this load data, you may want to use the same weather file to ensure that the energy model results are consistent with the load data. Choose the weather file on the Location and Ambient Conditions page.

To visit the EnergyPlus file generator website, click **EERE Building Technologies Program EnergyPlus**

Load Calculator. The websites URL is http://apps1.eere.energy.gov/buildings/energyplus/cfm/inputs/.

Working with Monthly Utility Bill Data

In some cases, the only data you may have about a building or facility load may be monthly utility bills showing monthly electricity usage in kWh/month, and perhaps a monthly peak consumption value in kW. This data is insufficient for SAM to model the system's performance because SAM requires a load value for each of the 8,760 hours in a year.

The "Normalize supplied load profile to monthly utility bill data" feature provides one way to work with monthly electric usage data in SAM. To use it, you first specify hourly load data using the User Entered Hourly Data option, and then enter the monthly usage data. SAM scales the hourly data so that it matches the monthly usage data.

> **Note.** SAM comes with a set of computer-generated hourly load data files for some cities in the United States. These files may be suitable for you to get started with your analysis. See Working with Time Series Load Data for more details.

To enter monthly usage data:

1. Under Electric Load Data, click **User entered hourly data**.
2. Click **Edit data** and specify the hourly data.

   If you do not have hourly load data, you can use one of the computer-generated load files that comes with SAM.
3. Check **Normalize supplied load profile to monthly utility bill data**.
4. Click **Edit Values**.
5. Type the 12 monthly usage values in the table.

   If the monthly usage is constant, enter the value under **Single Value** and click **Apply**.
6. Click **OK**.

Working with Time Series Load Data

SAM requires time series load data with at least hourly resolution to run simulations involving an electric load. You can either import the data from a properly formatted text file, or copy and paste the data from a spreadsheet program or other software.

If you do not have access to hourly or sub-hourly electric load data, you can use one of the following options:

- Specify a set of 12 daily profiles by month.
- Use one of the computer-generated residential load data sets for different cities in the United States that comes with SAM. This data may be suitable for preliminary analyses before you have access to better quality data. See Importing Data from a File below for instructions.

Data Sources

The following examples are some sources of electric load data:

- Electrical measurements from a building or other load center. Some electricity service providers make load data available to their customers.

- Data generated by a building simulation model, such as the EnergyPlus Example File Generator, http://apps1.eere.energy.gov/buildings/energyplus/cfm/inputs/.
- Some electric service area operators provide system-wide load data on their websites. For examples, see California ISO and Midwest ISO websites.
- Sample residential load data generated by the EnergyPlus load data generator supplied with SAM in *\samples\Simulated Electric Load Data - Residential* folder.

Time Step and Convention

SAM requires load data in a single column of average kilowatt per time step values. The number of data rows depends on the time step.

For hourly data, SAM requires a column of 8,760 data rows, where each row contains a value in kilowatts representing the average power required by the load over the hour. For sub-hourly data, SAM requires a column of 8,760 × Number of Times Steps per Hour data rows, with kilowatt values representing the average electric power over the period of a single time step.

The time convention must follow the time convention of the weather data specified on the Location and Resource, Wind Resource, Location and Ambient Conditions, or Ambient Conditions page. For NREL typical meteorological year data (TMY2 and TMY3), the first row of data represents the time step beginning at midnight on January 1. SAM assumes that January first is a Monday.

When you use sub-hourly load data with hourly weather data, SAM uses hourly average load values to for the energy charge calculations, and the sub-hourly data to determine the peak load for demand charges.

Importing Data from a File

SAM can import data from a text file that contains a single column of values representing the load in a single year. SAM ignores the first row, so you can use that row to store text describing the data. The number of rows depends on the number of time steps. For hourly data, the file should contain a total of 8,761 rows: The first row for header information, and the remaining rows for the load data. For 15-minute data, the file should contain 1 + 8760 x 4 = 35,041 rows.

To import load data from a properly formatted text file:

1. Under **Electric Load Data**, click **User entered data**.
2. Click **Edit Data**.
3. In the Edit Data window, click **Import**.
4. Navigate to the folder containing the load data file and open the file. For example to import data from one of the computer-generated residential load files included with SAM, navigate to *C:\SAM\[version number]\samples\Simulated Electric Load Data - Residential*.

   SAM displays the data in the data table. Use the scroll bar to see all of the data.
5. Click **OK** to return to the Electric Load page.

   SAM displays monthly and annual load data under **Hourly Simulation Load Profile Data**.

After importing the data, you can use the scaling and escalation factors on the Electric Load page to scale the entire data set up or down, and to model a load that increases from year to year by the percentage that you specify.

Pasting Load Data from your Computer's Clipboard

If you have load data in a spreadsheet or other program that allows you to copy columns of data to your computer's clipboard, you can paste the data into SAM. The data should be a single column of values in kilowatt-hours representing the load in a single year. The number of rows depends on the number of time steps. For hourly data, the column should contain 8,760 rows of load data.

To paste load data from your computer's clipboard:

1. Under **Electric Load Data**, click **User entered data**.
2. Click **Edit Data**.
3. Open the spreadsheet or other program containing the load data. The data must be in a single column with the appropriate number of rows for the data's time step.
4. Select the entire column of data and copy it.
5. In SAM's Edit Data window, click **Paste**.

   SAM displays the data in the data table. Use the scroll bar to see all of the data.
6. Click **OK** to return to the Electric Load page.

   SAM displays monthly and annual load data under **Hourly Simulation Load Profile Data**.

Creating Load Data from Daily Profiles

If you do not have a complete 8,760 set of load data, you specify the load using a set of daily load profiles for each month. SAM creates a set of 8,760 values representing the load for an entire year. When you define a load with daily load profiles, SAM assumes that the load for all days in a given month is identical.

To create a load data set using daily load profiles:

1. Under Electric Load Data, click Monthly schedule.
2. Click **Edit monthly schedule**.
3. In the Edit Monthly Schedule window, click **Weekday Values**.
4. For each month of the year, define a daily load profile by typing a value in kilowatt-hours for each of the 24 hours of the day. The first column represents the first hour of the day, beginning at midnight and ending at 1:00 a.m. SAM assumes that January 1st is a Monday.
5. Click **Weekend Values**.
6. Repeat Step 4 to define the daily load profile for Saturdays and Sundays. SAM assumes that January 6 is a Saturday.
7. Click **OK** to return to the Electric Load page.

   SAM displays monthly and annual load data under **Hourly Simulation Load Profile Data**..

15 System Costs

The System Costs page allows you to specify project installation costs, and operation and maintenance (O&M) costs.

For a general description of the system costs page, see System Costs Overview.

SAM displays different cost categories on the System Costs page, depending on the technology.

- Photovoltaic (PV) Systems (Flat Plate PV and PVWatts)
- High Concentration PV (HCPV) Systems
- Parabolic Trough
- Power Tower
- Linear Fresnel
- Dish Stirling
- Generic Solar Model
- Generic Model
- Solar Water Heating
- Wind Power
- Geothermal Power
- Geothermal Co-Production
- Biopower System and Biomass Feedstock

15.1 System Costs Overview

When you run SAM, you provide information about the cost of installing and operating the system by specifying inputs on the System Costs page. SAM organizes the costs into three categories:

- Direct capital costs for equipment purchases and installation labor
- Indirect capital costs for permitting, engineering, and land-related costs
- Operation and maintenance costs for labor, equipment, and other costs associated with operating the project

You can also specify costs associated with financing the project on the Financing page:

- Construction loan
- Project loan
- Taxes and insurance
- Fees associated with the project structure for projects involving two partners or a lease

When you create a new case or file, SAM populates inputs with default values to help you get started with your analysis. If you create a case for a utility-scale photovoltaic project with a single owner, SAM populates the inputs on the Financing and System Costs pages with values that are reasonable for a typical PV project for power generation in the United States. The default values are just a starting point: As you develop and refine your analysis, you should change the inputs to values that are appropriate for your analysis scenario.

For example, the default module cost for a PV project with the utility single owner financing option in SAM 2012.5.11 is $1.95/Wdc. That cost is based on NREL research on benchmark prices in the United States to help the U.S. Department of Energy's Solar Energy Program evaluate its programs (see references below). Obviously, the module price for a real project is likely to be different than the benchmark U.S. price, and it is up to you to determine appropriate costs for your analysis. For the other technologies (concentrating solar power, wind, biomass, geothermal, and solar water heating), the default costs are similarly representative values based on the U.S. market at the time of the SAM release.

Note. For a list of web resources with costs for renewable energy projects, see the list toward the bottom of the System Cost Data page on the SAM website.

SAM displays different cost categories on the System Costs page for different technologies:

- Photovoltaic (PV) Systems
- Parabolic Trough
- Power Tower
- Linear Fresnel
- Dish Stirling
- Generic Solar Model
- Generic Model
- Solar Water Heating
- Wind Power
- Geothermal Power
- Geothermal Co-Production
- Biopower System and Biomass Feedstock

15.2 PV System Costs

The PV System Costs page provides access to variables that define the installation and operating costs of a photovoltaic project. Debt-related and tax costs are specified on the Financing page.

SAM uses the variables on the PV System Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

SAM provides the categories under **Direct Capital Costs** and **Indirect Capital Costs** for your convenience to help keep track of project installation costs. Only the **Total Installed Cost** value affects the cash flow calculations, so you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the array to the module cost category or to the engineering category with equivalent results. After you assign costs to the categories, you should verify that the total installed cost value is what you expect. SAM accounts for the total installed cost in Year 0 of the project cash flow.

The Operation and Maintenance Costs categories are where you specify recurring project costs. SAM reports these annual costs in the project cash flow under the Operating Expenses heading.

Note. The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

Note: Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

Module ($/Wdc or $/Unit)

For the Flat Plate PV model, the module cost is expressed per unit or per DC Watt:

- Dollars per DC watt multiplied by **Nameplate Capacity (at reference conditions)** on the Array page, or
- Dollars per unit multiplied by **Total Modules** on the Array page.

For the PVWatts System Model, the module cost is expressed per unit or per DC Watt:

- Dollars per watt multiplied by **Nameplate Capacity** on the PVWatts Solar Array page, or
- Dollars per unit, where the number of modules is assumed to be one.

Inverter ($/Wac or $/Unit)

For the Flat Plate PV model, the cost of inverters in the system is expressed in dollars per AC Watt or dollars per inverter:

- Dollars per AC watt multiplied by **Total Inverter Capacity** on the Array page, or
- Dollars per unit multiplied by **Number of Inverters** in the **Actual Layout** column on the Array page.

For the PVWatts System Model, the inverter cost is either dollars per watt or dollars per inverter:

- Dollars per watt multiplied by the product of **DC Rating** and **DC to AC Derate Factor** on the PVWatts Solar Array page, or
- Dollars per unit where the number of inverters is assumed to be one.

The other direct capital cost categories, **Tracking Equipment** (HCPV only), **Balance of system**, **Installation labor**, and **Installer margin and overhead** can be specified using three units. SAM calculates the total amount for each category as shown below.

$

A fixed cost in dollars.

$/Wdc

A cost proportional to the system's DC nameplate capacity, equal to the **Nameplate Capacity** on the Array page for the Flat Plate PV model, or the **DC Rating** on the PVWatts Solar Array page for the PVWatts model.

$/m2

Applies only to the Flat Plate PV model. A cost proportional to the total module area of the array in square meters, equal to the **Total Area** on the Array page. This option is not active for the PVWatts model.

Total

For each category, the total is the sum of the three units.

Total = $ + $/Wdc × Nameplate Capacity (Wdc) + $/m2 × Total Area (m2)

Contingency (%)

A percentage of the sum of the module, inverter, balance of system, installation labor, and installer margin and overhead costs that you can use to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of module, inverter, balance of system, installation labor, installer margin and overhead costs, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

> **Note:** Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

The five indirect cost categories, **Permitting - Environmental Studies**, **Engineering**, **Grid interconnection** are each calculated as the sum of the three values expressed with the following units:

% of Direct Cost

A percentage of the **Total Direct Cost** value shown under Direct Capital Costs.

Cost $/Wdc

A cost proportional to the system's DC nameplate capacity, equal to the **Nameplate Capacity** on the Array page for the Flat Plate PV model, or the **DC Rating** on the PVWatts Solar Array page for the PVWatts model.

Fixed Cost

A fixed cost in dollars.

Total

For each category, the total is the sum of the three units:

Total = % of Direct Cost × Total Direct Cost ($) + Cost $/Wdc × Nameplate Capacity (Wdc) + Fixed Cost ($)

Land Costs

SAM calculates the total land cost as the sum of **Land** and **Land Preparation**. The land cost categories use the Cost $/acre category in addition to the categories for the other indirect costs (% of Direct Cost,

Cost $/Wdc, Fixed Cost).

Total Land Area

The total land area from the Array page.

Cost $/acre

A cost in dollars per acre of total land area.

Total

For each land cost category, the total is the sum of the three units:

Total = Cost $/acre + % of Direct Cost × Total Direct Cost ($) + Cost $/Wdc × Nameplate Capacity (Wdc) + Fixed Cost ($)

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of the five indirect cost categories and the sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page and Depreciation page.

Total Installed Cost ($)

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow in Years 1 and later..

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Specifying O&M Costs in Specific Years

SAM allows you to specify any of the four operation and maintenance (O&M) cost categories on the System Costs page either as a single annual cost, or using a table of values to specify an annual schedule of costs. An annual schedule makes it possible to assign costs to particular years in the analysis period. Annual schedules can be used to account for component replacement costs and other periodic costs that do not recur on a regular annual basis.

You choose whether to specify an O&M cost as a single annual value or an annual schedule with the grey and blue button next to each variable. SAM uses the option indicated by the blue highlight on the button: A blue highlighted “Value” indicates a single, regularly occurring annual value. A blue highlighted “Sched” indicates that the value is specified as an annual schedule.

For example, to account for component replacement costs, you can specify the fixed annual cost category as an annual schedule, and assign the cost of replacing or rebuilding the component to particular years. For a 30-year project using a component with a seven-year life, you would assign a replacement cost to years seven, 14, and 21. Or, to account for expected improvements in the component's reliability in the future, you could assign component replacement costs in years seven, 17, and 27. After running simulations, you can see the replacement costs in the project cash flow in the appropriate column under Operating Expenses. SAM accounts for the operating costs in the other economic metrics including the levelized cost of energy and net present value.

Notes.

If you use the annual schedule option to specify equipment replacement costs, SAM does not calculate any residual or salvage value of system components based on the annual schedule. SAM calculates salvage value separately, using the salvage value you specify on the Financing page.

Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

The following procedure describes how to define the fixed annual cost category as an annual schedule. You can use the same procedure for any of the other operation and maintenance cost categories.

<u>**To assign component replacement costs to particular years:**</u>

1. In the Fixed Annual Cost category, note that the "Value" label of the grey and blue button is blue indicating that the single value mode is active for the variable.

In this case, SAM would assign an annual cost of $284 to each year in the project cash flow.

2. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.

3. Click **Edit**.
4. In the Edit Schedule window, use the vertical scroll bar to find the year of the first replacement, and type the replacement cost in current or constant dollars for that year.

   To delete a value, select it and press the Delete key on your keyboard.

> **Note.** You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no annual costs.

5. When you have finished editing the schedule, click **Accept**.

Because you must specify an O&M cost category as either an annual cost or annual schedule, to assign both a recurring annual fixed cost and periodic replacement cost, you must type the recurring cost in each year of the annual schedule, and for years with replacement costs, type the sum of the recurring and replacement costs.

15.3 HCPV Costs

The HCPV System Costs page provides access to variables that define the installation and operating costs of a high-X concentrating PV project. Debt-related and tax costs are specified on the Financing page.

SAM uses the variables on the HCPV System Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

SAM provides the categories under **Direct Capital Costs** and **Indirect Capital Costs** for your convenience to help keep track of project installation costs. Only the **Total Installed Cost** value affects the cash flow calculations, so you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the array to the module cost category or to the engineering category with equivalent results. After you assign costs to the categories, you should verify that the total installed cost value is what you expect. SAM accounts for the total installed cost in Year 0 of the project cash flow.

The Operation and Maintenance Costs categories are where you specify recurring project costs. SAM reports these annual costs in the project cash flow under the Operating Expenses heading.

> **Note.** The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

> **Note:** Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

Module ($/Wdc or $/Unit)

For the Flat Plate PV model, the module cost is expressed per unit or per DC Watt:

- Dollars per DC watt multiplied by **Nameplate Capacity (at reference conditions)** on the Array page, or
- Dollars per unit multiplied by **Total Modules** on the Array page.

For the PVWatts System Model, the module cost is expressed per unit or per DC Watt:

- Dollars per watt multiplied by **Nameplate Capacity** on the PVWatts Solar Array page, or
- Dollars per unit, where the number of modules is assumed to be one.

Inverter ($/Wac or $/Unit)

For the Flat Plate PV model, the cost of inverters in the system is expressed in dollars per AC Watt or dollars per inverter:

- Dollars per AC watt multiplied by **Total Inverter Capacity** on the Array page, or
- Dollars per unit multiplied by **Number of Inverters** in the **Actual Layout** column on the Array page.

For the PVWatts System Model, the inverter cost is either dollars per watt or dollars per inverter:

- Dollars per watt multiplied by the product of **DC Rating** and **DC to AC Derate Factor** on the PVWatts Solar Array page, or
- Dollars per unit where the number of inverters is assumed to be one.

The other direct capital cost categories, **Tracking Equipment**, **Balance of system**, **Installation labor**, and **Installer margin and overhead** can be specified using three units. SAM calculates the total amount for each category as shown below.

$

A fixed cost in dollars.

$/Wdc

A cost proportional to the system's DC nameplate capacity, equal to the **Nameplate Capacity** on the Array page for the Flat Plate PV model, or the **DC Rating** on the PVWatts Solar Array page for the PVWatts model.

$/m2

Applies only to the Flat Plate PV model. A cost proportional to the total module area of the array in square meters, equal to the **Total Area** on the Array page. This option is not active for the PVWatts model.

Total

For each category, the total is the sum of the three units.

Total = $ + $/Wdc × Nameplate Capacity (Wdc) + $/m2 × Total Area (m2)

Contingency (%)

A percentage of the sum of the module, inverter, balance of system, installation labor, and installer margin and overhead costs that you can use to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of module, inverter, balance of system, installation labor, installer margin and overhead costs, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

> **Note:** Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

The five indirect cost categories, **Permitting - Environmental Studies**, **Engineering**, **Grid interconnection** are each calculated as the sum of the three values expressed with the following units:

% of Direct Cost

A percentage of the **Total Direct Cost** value shown under Direct Capital Costs.

Cost $/Wdc

A cost proportional to the system's DC nameplate capacity, equal to the **Nameplate Capacity** on the Array page for the Flat Plate PV model, or the **DC Rating** on the PVWatts Solar Array page for the PVWatts model.

Fixed Cost

A fixed cost in dollars.

Total

For each category, the total is the sum of the three units:

Total = % of Direct Cost × Total Direct Cost ($) + Cost $/Wdc × Nameplate Capacity (Wdc) + Fixed Cost ($)

Land Costs

SAM calculates the total land cost as the sum of **Land** and **Land Preparation**. The land cost categories use the Cost $/acre category in addition to the categories for the other indirect costs (% of Direct Cost, Cost $/Wdc, Fixed Cost).

Total Land Area

The total land area from the Array page.

Cost $/acre

A cost in dollars per acre of total land area.

Total

For each land cost category, the total is the sum of the three units:

Total = Cost $/acre + % of Direct Cost × Total Direct Cost ($) + Cost $/Wdc × Nameplate Capacity (Wdc) + Fixed Cost ($)

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of the five indirect cost categories and the sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page.

Total Installed Cost ($)

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow in Years 1 and later..

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours.

The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Specifying O&M Costs in Specific Years

SAM allows you to specify any of the four operation and maintenance (O&M) cost categories on the System Costs page either as a single annual cost, or using a table of values to specify an annual schedule of costs. An annual schedule makes it possible to assign costs to particular years in the analysis period. Annual schedules can be used to account for component replacement costs and other periodic costs that do not recur on a regular annual basis.

You choose whether to specify an O&M cost as a single annual value or an annual schedule with the grey and blue button next to each variable. SAM uses the option indicated by the blue highlight on the button: A blue highlighted “Value” indicates a single, regularly occurring annual value. A blue highlighted “Sched” indicates that the value is specified as an annual schedule.

For example, to account for component replacement costs, you can specify the fixed annual cost category as an annual schedule, and assign the cost of replacing or rebuilding the component to particular years. For a 30-year project using a component with a seven-year life, you would assign a replacement cost to years seven, 14, and 21. Or, to account for expected improvements in the component's reliability in the future, you could assign component replacement costs in years seven, 17, and 27. After running simulations, you can see the replacement costs in the project cash flow in the appropriate column under Operating Expenses. SAM accounts for the operating costs in the other economic metrics including the levelized cost of energy and net present value.

Notes.

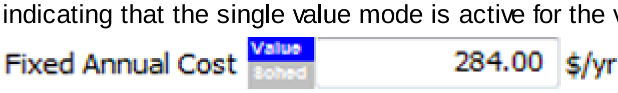
If you use the annual schedule option to specify equipment replacement costs, SAM does not calculate any residual or salvage value of system components based on the annual schedule. SAM calculates salvage value separately, using the salvage value you specify on the Financing page.

Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

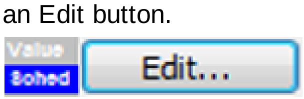
The following procedure describes how to define the fixed annual cost category as an annual schedule. You can use the same procedure for any of the other operation and maintenance cost categories.

To assign component replacement costs to particular years:

1. In the Fixed Annual Cost category, note that the "Value" label of the grey and blue button is blue indicating that the single value mode is active for the variable.

   In this case, SAM would assign an annual cost of $284 to each year in the project cash flow.
2. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.

3. Click **Edit**.
4. In the Edit Schedule window, use the vertical scroll bar to find the year of the first replacement, and

type the replacement cost in current or constant dollars for that year.

To delete a value, select it and press the Delete key on your keyboard.

Note. You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no annual costs.

5. When you have finished editing the schedule, click **Accept**.

Because you must specify an O&M cost category as either an annual cost or annual schedule, to assign both a recurring annual fixed cost and periodic replacement cost, you must type the recurring cost in each year of the annual schedule, and for years with replacement costs, type the sum of the recurring and replacement costs.

15.4 Trough System Costs

To view the Trough System Costs page, click **Trough System Costs** on the main window's navigation menu. Note that for the empirical trough input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Empirical Trough System.

Contents

Overview

SAM uses the variables on the Trough System Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics reported in the Metrics table on the Results page.

Because only the Total Installed Cost value affects the cash flow calculations, you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the solar field to the solar field cost category or to the engineer-procure-construct category with equivalent results. The categories are provided to help you keep track of the different costs, but do not affect the economic calculations. After assigning costs to the categories, verify that the total installed costs value is what you expect.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

CSP System Cost Notes.

The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

The direct capital costs in $/kWe are in kilowatts of gross power block capacity rather than nameplate capacity because the size and cost of the power block is determined by the gross capacity, not the net capacity. The total installed cost in $/kWe (actually overnight installed cost because it does not include financing during construction costs, which are accounted for on the Financing page) is in kilowatts of nameplate capacity, because that is what is delivered to the grid and is consistent with how costs are reported for utility generation technologies. The indirect costs in $/Wac are in Watts of nameplate power block capacity because those costs that use the entire plant as the basis, not just the power block.

Input Variable Reference

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

Note: Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

Site Improvements ($/m²)

A cost per square meter of solar field area to account for expenses related to site preparation and other equipment not included in the solar field cost category.

Solar Field ($/m²)

A cost per square meter of solar field area to account for expenses related to installation of the solar field, including labor and equipment.

HTF System ($/m²)

A cost per square meter of solar field area to account for expenses related to installation of the heat transfer fluid pumps and piping, including labor and equipment.

Storage ($/kWht)

Cost per thermal megawatt-hour of storage capacity to account for expenses related to installation of the thermal storage system, including equipment and labor.

Fossil Backup ($/kWe)

Cost per electric megawatt of power block gross capacity to account for the installation of a fossil backup system, including equipment and labor.

Power Plant ($/kWe)

Cost per electric megawatt of power block gross capacity to account for the installation of the power block, including equipment and labor.

Balance of Plant ($/kWe)

Cost per electric megawatt of power block gross capacity to account for additional costs.

Contingency (%)

A percentage of the sum of the site improvements, solar field, HTF system, storage, fossil backup, and power plant costs to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of improvements, solar field, HTF system, storage, fossil backup, power plant costs, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

> **Note:** Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

Total Land Area

The total land area required for the project, from the Solar Field or Heliostat Field page.

Nameplate

The system's nameplate capacity from the Power Block or Power Cycle page.

EPC and Owner Costs

EPC (engineer-procure-construct) and owner costs are associated with the design and construction of the project. SAM calculates the total cost as the sum of the Non-fixed Cost and Fixed Cost.

Typical costs that may be appropriate to include in the EPC and Owner category are: Permitting, royalty payments, consulting, management or legal fees, geotechnical and environmental surveys, interconnection costs, spare parts inventories, commissioning costs, and the owner's engineering and project development activities.

Total Land Costs

Costs associated with land purchases, which SAM calculates as the sum of a non-fixed cost and a fixed cost. Use the Land category described below for land costs, and inputs on the Financing page for financing costs.

Units for Land and EPC Costs

SAM calculates the total EPC and Owner Costs and Total Land Costs by adding the four costs that you can specify using different units:

Cost per acre

A cost in dollars per total land area in acres.

% of Direct Cost

A cost as a percentage of **Total Direct Cost** under **Direct Capital Cost**.

Cost per Wac

A cost in dollars per AC Watt of nameplate capacity.

Fixed Cost

A fixed dollar amount

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of engineer-procure-construct costs, project-land-miscellaneous costs, and sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page.

Total Installed Cost

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow.

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Fossil Fuel Cost ($/MMBtu)

The cost per million British thermal units for fuel. SAM uses the conversion factor 1 MWh = 3.413 MMBtu. SAM calculates a fossil fuel cost for concentrating solar power systems with fossil backup, and for the generic system when the heat rate on the Power Plant page is not zero.

Note. If you are using the generic system model to represent a system that does not consume fuel, you should use a fuel cost of zero.

Entering Periodic Operation and Maintenance Costs

SAM allows you to specify any of the four operation and maintenance (O&M) cost categories on the System Costs page either as a single annual cost, or using a table of values to specify an annual schedule of costs. An annual schedule makes it possible to assign costs to particular years in the analysis period. Annual schedules can be used to account for component replacement costs and other periodic costs that do not recur on a regular annual basis.

You choose whether to specify an O&M cost as a single annual value or an annual schedule with the grey and blue button next to each variable. SAM uses the option indicated by the blue highlight on the button: A blue highlighted “Value” indicates a single, regularly occurring annual value. A blue highlighted “Sched” indicates that the value is specified as an annual schedule.

For example, to account for component replacement costs, you can specify the fixed annual cost category as an annual schedule, and assign the cost of replacing or rebuilding the component to particular years. For a 30-year project using a component with a seven-year life, you would assign a replacement cost to years seven, 14, and 21. Or, to account for expected improvements in the component's reliability in the future, you could assign component replacement costs in years seven, 17, and 27. After running simulations, you can see the replacement costs in the project cash flow in the appropriate column under Operating Expenses. SAM accounts for the operating costs in the other economic metrics including the levelized cost of energy and net present value.

Notes.

If you use the annual schedule option to specify equipment replacement costs, SAM does not calculate any residual or salvage value of system components based on the annual schedule. SAM calculates salvage value separately, using the salvage value you specify on the Financing page.

Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

The following procedure describes how to define the fixed annual cost category as an annual schedule. You can use the same procedure for any of the other operation and maintenance cost categories.

To assign component replacement costs to particular years:

1. In the Fixed Annual Cost category, note that the "Value" label of the grey and blue button is blue

indicating that the single value mode is active for the variable.

In this case, SAM would assign an annual cost of $284 to each year in the project cash flow.

2. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.

3. Click **Edit**.
4. In the Edit Schedule window, use the vertical scroll bar to find the year of the first replacement, and type the replacement cost in current or constant dollars for that year.

   To delete a value, select it and press the Delete key on your keyboard.

> **Note.** You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no annual costs.

5. When you have finished editing the schedule, click **Accept**.

Because you must specify an O&M cost category as either an annual cost or annual schedule, to assign both a recurring annual fixed cost and periodic replacement cost, you must type the recurring cost in each year of the annual schedule, and for years with replacement costs, type the sum of the recurring and replacement costs.

About the CSP Default Cost Assumptions

The default values the System Costs page for the CSP models reflect the National Renewable Energy Laboratory's best estimate of representative system costs for the United States at the time of the SAM version release. The values are based on cost studies undertaken by NREL, review of published literature, and conversations with developers and industry insiders. Costs are reviewed prior to each new SAM release.

> **Note.** Always review all of the inputs for your SAM project to determine whether they are appropriate for your analysis.

The parabolic trough and power tower costs are heavily influenced by two studies:

1. C.S. Turchi, "Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM)," NREL/TP-550-47605, 2010. (PDF 7.2 MB)
2. G. J. Kolb, C. K. Ho, T. R. Mancini, and J. A. Gary, "Power Tower Technology Roadmap and Cost Reduction Plan," SAND2011-2419, 2011. (PDF 503 KB)

These studies differed in some important assumptions. The differences in the location and cooling method assumptions for the default cases of the CSP technologies are outlined in the following table. The choice of location affects solar resource and the assumed labor costs associated with the case. Construction labor rates in Arizona tend to be lower than in California, which reduces installed costs. The trough, linear Fresnel, and generic solar systems are assumed to use evaporative cooling (i.e., a “wet” system). The power tower systems are assumed to be dry cooled. However, the cooling method is not unique to the technologies, and SAM allows the user to change the cooling system if desired. Note that if one switches power cycle cooling system, the power block costs would be expected to change. Perhaps less obvious, the site preparation costs are lower for dry-cooled systems, due to the elimination of the large blowdown evaporation ponds required with wet systems. These changes do not occur automatically in SAM; relevant system costs must be adjusted by the user.

Technology	Default Location	Default Cooling method
Physical Trough	SW Arizona (Tucson weather file)	Wet
Empirical Trough	SW Arizona (Tucson weather file)	Wet
Molten Salt Power Tower	Southern California (Daggett weather file)	Dry
Direct Steam Power Tower	Southern California (Daggett weather file)	Dry
Linear Fresnel	SW Arizona (Tucson weather file)	Wet
Dish Stirling	Arizona (Phoenix weather file)	Dry
Generic Solar	SW Arizona (Tucson weather file)	Wet

The trough, tower, and linear Fresnel models assume the “balance of plant” cost category is composed of the steam generation system. This is consistent with reference [2] above. This choice is made to allow users to highlight the effect of a direct steam generation (DSG) design. In a DSG design, the balance of plant cost category is zero because steam generation occurs in the solar receiver.

The lesser commercial activity in dish Stirling and linear Fresnel systems makes cost values for those technologies more uncertain than for troughs and towers. Dish Stirling and linear Fresnel costs are estimated based on discussions with developers and researchers.

15.5 Tower System Costs

To view the Tower System Costs page, click **Tower System Costs** on the main window's navigation menu. Note that for the power tower input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Power Tower System.

Contents

- Overview describes the Tower System Costs page.
- Input Variable Reference describes the input variables on the Tower System Costs page.
- Entering Periodic Operation and Maintenance Costs explains how to use annual schedules to assign operation and maintenance costs to particular years in the project cash flow.
- About the CSP Default Cost Assumptions describes the assumptions and sources of the default parabolic trough system costs.

Overview

SAM uses the variables on the Tower System Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics reported in the Metrics table on the Results page.

Because only the Total Installed Cost value affects the cash flow calculations, you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the solar field to the solar field cost category or to the engineer-procure-construct category with equivalent results. The categories are provided to help you keep track of the different costs, but do not affect the economic calculations. After assigning costs to the categories, verify that the total installed costs value is what you expect.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

CSP System Cost Notes.

The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

The direct capital costs in $/kWe are in kilowatts of gross power block capacity rather than nameplate capacity because the size and cost of the power block is determined by the gross capacity, not the net capacity. The total installed cost in $/kWe (actually overnight installed cost because it does not include financing during construction costs, which are accounted for on the Financing page) is in kilowatts of nameplate capacity, because that is what is delivered to the grid and is consistent with how costs are reported for utility generation technologies. The indirect costs in $/Wac are in Watts of nameplate power block capacity because those costs that use the entire plant as the basis, not just the power block.

Input Variable Reference

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

Note: Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

Site Improvements ($/m^2)

A cost per square meter of total reflective area from the Heliostat Field page to account for expenses related to site preparation and other equipment not included in the heliostat field cost category.

Heliostat Field ($/m^2)

A cost per square meter of total reflective area from the Heliostat Field page to account for expenses related to installation of the heliostats, including heliostat parts, field wiring, drives, labor, and equipment.

Balance of Plant ($/kWe)

A cost per electric kilowatt of power cycle gross capacity from the Power Cycle page expenses related to installation of the balance-of-plant components and controls, and construction of buildings, including labor and equipment.

Power Block ($/kWe)

A cost per electric kilowatt of power cycle gross capacity from the Power Cycle page expenses related to installation of the power block components, including labor and equipment. The Power Block and Balance of Plant costs are rolled together into a single number for calculation purposes.

Fossil Backup ($/kWe)

Cost per electric kilowatt of power block gross capacity to account for the installation of a fossil backup system, including equipment and labor.

Storage ($/kWht)

Cost per thermal megawatt-hour of storage capacity from the Thermal Storage page to account for the installation of a thermal energy storage system, including equipment and labor.

Fixed Solar Field Cost ($)

An additional fixed cost in dollars to include as a direct cost that is not accounted for by any of the above categories.

Fixed Tower Cost ($)

A fixed cost to account for tower construction, materials and labor costs. The fixed tower cost serves as the multiplier in the tower cost scaling equation shown below.

Tower Cost Scaling Exponent

SAM uses the tower cost in the optimization calculations. The tower cost scaling exponent defines the nonlinear relationship between tower cost and tower height. See Total Tower Cost below.

Total Tower Cost ($)

Total Tower Cost = Fixed Tower Costs x e ^ (Tower Height x Tower Cost Scaling Exponent)

Receiver Reference Cost ($)

The cost per receiver reference area to account for receiver installation costs, including labor and equipment.

Receiver Reference Area (m^2)

The receiver area on which the receiver reference cost is based.

Receiver Cost Scaling Exponent

SAM uses the receiver cost in the optimization calculations. The receiver cost scaling exponent defines the nonlinear relationship between receiver cost and receiver area based on the reference cost conditions provided.

Total Receiver Cost ($)

Receiver Cost = Receiver Reference Cost x (Receiver Area / Receiver Reference Area) ^ Receiver Cost Scaling Exponent.

Contingency (%)

A percentage of the sum of the site improvements, heliostat field, balance of plant, power block, storage system, fixed solar field, total tower, and total receiver costs to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of improvements, site improvements, heliostat field, balance of plant, power block, storage system, fixed solar field, total tower, total receiver, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

> **Note:** Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

Total Land Area

The total land area required for the project, from the Solar Field or Heliostat Field page.

Nameplate

The system's nameplate capacity from the Power Block or Power Cycle page.

EPC and Owner Costs

EPC (engineer-procure-construct) and owner costs are associated with the design and construction of the project. SAM calculates the total cost as the sum of the Non-fixed Cost and Fixed Cost.

Typical costs that may be appropriate to include in the EPC and Owner category are: Permitting, royalty payments, consulting, management or legal fees, geotechnical and environmental surveys, interconnection costs, spare parts inventories, commissioning costs, and the owner's engineering and project development activities.

Total Land Costs

Costs associated with land purchases, which SAM calculates as the sum of a non-fixed cost and a fixed cost. Use the Land category described below for land costs, and inputs on the Financing page for financing costs.

Units for Land and EPC Costs

SAM calculates the total EPC and Owner Costs and Total Land Costs by adding the four costs that you can specify using different units:

Cost per acre

A cost in dollars per total land area in acres.

% of Direct Cost

A cost as a percentage of **Total Direct Cost** under **Direct Capital Cost**.

Cost per Wac

A cost in dollars per AC Watt of nameplate capacity.

Fixed Cost

A fixed dollar amount

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of engineer-procure-construct costs, project-land-miscellaneous costs, and sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page.

Total Installed Cost

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow.

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Fossil Fuel Cost ($/MMBtu)

The cost per million British thermal units for fuel. SAM uses the conversion factor 1 MWh = 3.413 MMBtu. SAM calculates a fossil fuel cost for concentrating solar power systems with fossil backup, and for the generic system when the heat rate on the Power Plant page is not zero.

Note. If you are using the generic system model to represent a system that does not consume fuel, you should use a fuel cost of zero.

Note. For information on water consumption and other operation and maintenance costs and requirements for concentrating parabolic trough systems, see the Troughnet website: http://www.nrel.gov/csp/troughnet/power_plant_systems.html. For information on operation and maintenance costs for photovoltaic systems, see the California Energy Commission's online Distributed Energy Resource guide http://www.energy.ca.gov/distgen/economics/operation.html.

Entering Periodic Operation and Maintenance Costs

SAM allows you to specify any of the four operation and maintenance (O&M) cost categories on the System Costs page either as a single annual cost, or using a table of values to specify an annual schedule of costs. An annual schedule makes it possible to assign costs to particular years in the analysis period. Annual schedules can be used to account for component replacement costs and other periodic costs that do not recur on a regular annual basis.

You choose whether to specify an O&M cost as a single annual value or an annual schedule with the grey and blue button next to each variable. SAM uses the option indicated by the blue highlight on the button: A blue highlighted “Value” indicates a single, regularly occurring annual value. A blue highlighted “Sched” indicates that the value is specified as an annual schedule.

For example, to account for component replacement costs, you can specify the fixed annual cost category as an annual schedule, and assign the cost of replacing or rebuilding the component to particular years. For a 30-year project using a component with a seven-year life, you would assign a replacement cost to years seven, 14, and 21. Or, to account for expected improvements in the component's reliability in the future, you could assign component replacement costs in years seven, 17, and 27. After running simulations, you can see the replacement costs in the project cash flow in the appropriate column under Operating Expenses. SAM accounts for the operating costs in the other economic metrics including the levelized cost of energy and net present value.

Notes.

If you use the annual schedule option to specify equipment replacement costs, SAM does not calculate any residual or salvage value of system components based on the annual schedule. SAM calculates salvage value separately, using the salvage value you specify on the Financing page.

Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

The following procedure describes how to define the fixed annual cost category as an annual schedule. You can use the same procedure for any of the other operation and maintenance cost categories.

To assign component replacement costs to particular years:

1. In the Fixed Annual Cost category, note that the "Value" label of the grey and blue button is blue indicating that the single value mode is active for the variable.

   In this case, SAM would assign an annual cost of $284 to each year in the project cash flow.
2. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.

3. Click **Edit**.
4. In the Edit Schedule window, use the vertical scroll bar to find the year of the first replacement, and type the replacement cost in current or constant dollars for that year.

   To delete a value, select it and press the Delete key on your keyboard.

> **Note.** You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no annual costs.

5. When you have finished editing the schedule, click **Accept**.

Because you must specify an O&M cost category as either an annual cost or annual schedule, to assign both a recurring annual fixed cost and periodic replacement cost, you must type the recurring cost in each year of the annual schedule, and for years with replacement costs, type the sum of the recurring and replacement costs.

About the CSP Default Cost Assumptions

The default values the System Costs page for the CSP models reflect the National Renewable Energy Laboratory's best estimate of representative system costs for the United States at the time of the SAM version release. The values are based on cost studies undertaken by NREL, review of published literature, and conversations with developers and industry insiders. Costs are reviewed prior to each new SAM release.

> **Note.** Always review all of the inputs for your SAM project to determine whether they are appropriate for your analysis.

The parabolic trough and power tower costs are heavily influenced by two studies:

1. C.S. Turchi, "Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM)," NREL/TP-550-47605, 2010. (PDF 7.2 MB)
2. G. J. Kolb, C. K. Ho, T. R. Mancini, and J. A. Gary, "Power Tower Technology Roadmap and Cost Reduction Plan," SAND2011-2419, 2011. (PDF 503 KB)

These studies differed in some important assumptions. The differences in the location and cooling method assumptions for the default cases of the CSP technologies are outlined in the following table. The choice of location affects solar resource and the assumed labor costs associated with the case. Construction labor rates in Arizona tend to be lower than in California, which reduces installed costs. The trough, linear Fresnel, and generic solar systems are assumed to use evaporative cooling (i.e., a “wet” system). The power tower systems are assumed to be dry cooled. However, the cooling method is not unique to the technologies, and SAM allows the user to change the cooling system if desired. Note that if one switches power cycle cooling system, the power block costs would be expected to change. Perhaps less obvious, the site preparation costs are lower for dry-cooled systems, due to the elimination of the large blowdown evaporation ponds required with wet systems. These changes do not occur automatically in SAM; relevant system costs must be adjusted by the user.

Technology	Default Location	Default Cooling method
Physical Trough	SW Arizona (Tucson weather file)	Wet
Empirical Trough	SW Arizona (Tucson weather file)	Wet
Molten Salt Power Tower	Southern California (Daggett weather file)	Dry
Direct Steam Power Tower	Southern California (Daggett weather file)	Dry
Linear Fresnel	SW Arizona (Tucson weather file)	Wet
Dish Stirling	Arizona (Phoenix weather file)	Dry
Generic Solar	SW Arizona (Tucson weather file)	Wet

The trough, tower, and linear Fresnel models assume the “balance of plant” cost category is composed of the steam generation system. This is consistent with reference [2] above. This choice is made to allow users to highlight the effect of a direct steam generation (DSG) design. In a DSG design, the balance of plant cost category is zero because steam generation occurs in the solar receiver.

The lesser commercial activity in dish Stirling and linear Fresnel systems makes cost values for those technologies more uncertain than for troughs and towers. Dish Stirling and linear Fresnel costs are estimated based on discussions with developers and researchers.

15.6 Linear Fresnel System Costs

Contents

- Input Variable Reference describes the input variables on the Trough System Costs page.
- Entering Periodic Operation and Maintenance Costs explains how to use annual schedules to assign operation and maintenance costs to particular years in the project cash flow.
- About the CSP Default Cost Assumptions describes the assumptions and sources of the default parabolic trough system costs.

SAM uses the variables on the Linear Fresnel Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics reported in the

Metrics table on the Results page.

Because only the Total Installed Cost value affects the cash flow calculations, you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the solar field to the solar field cost category or to the engineer-procure-construct category with equivalent results. The categories are provided to help you keep track of the different costs, but do not affect the economic calculations. After assigning costs to the categories, verify that the total installed costs value is what you expect.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

CSP System Cost Notes.

The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

The direct capital costs in $/kWe are in kilowatts of gross power block capacity rather than nameplate capacity because the size and cost of the power block is determined by the gross capacity, not the net capacity. The total installed cost in $/kWe (actually overnight installed cost because it does not include financing during construction costs, which are accounted for on the Financing page) is in kilowatts of nameplate capacity, because that is what is delivered to the grid and is consistent with how costs are reported for utility generation technologies. The indirect costs in $/Wac are in Watts of nameplate power block capacity because those costs that use the entire plant as the basis, not just the power block.

Input Variable Reference

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

Note: Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

Site Improvements ($/m²)

A cost per square meter of solar field area to account for expenses related to site preparation and other equipment not included in the solar field cost category.

Solar Field ($/m²)

A cost per square meter of solar field area to account for expenses related to installation of the solar field, including labor and equipment.

HTF System ($/m²)

A cost per square meter of solar field area to account for expenses related to installation of the heat transfer fluid pumps and piping, including labor and equipment.

Fossil Backup ($/kWe)

Cost per electric megawatt of power block gross capacity to account for the installation of a fossil backup system, including equipment and labor.

Power Plant ($/kWe)

Cost per electric megawatt of power block gross capacity to account for the installation of the power block, including equipment and labor.

Balance of Plant ($/kWe)

Cost per electric megawatt of power block gross capacity to account for additional costs.

Contingency (%)

A percentage of the sum of the site improvements, solar field, HTF system, storage, fossil backup, and power plant costs to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of improvements, solar field, HTF system, storage, fossil backup, power plant costs, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

> **Note:** Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

Total Land Area

The total land area required for the project, from the Solar Field or Heliostat Field page.

Nameplate

The system's nameplate capacity from the Power Block or Power Cycle page.

EPC and Owner Costs

EPC (engineer-procure-construct) and owner costs are associated with the design and construction of the project. SAM calculates the total cost as the sum of the Non-fixed Cost and Fixed Cost.

Typical costs that may be appropriate to include in the EPC and Owner category are: Permitting, royalty payments, consulting, management or legal fees, geotechnical and environmental surveys, interconnection costs, spare parts inventories, commissioning costs, and the owner's engineering and project development activities.

Total Land Costs

Costs associated with land purchases, which SAM calculates as the sum of a non-fixed cost and a fixed cost. Use the Land category described below for land costs, and inputs on the Financing page for financing costs.

Units for Land and EPC Costs

SAM calculates the total EPC and Owner Costs and Total Land Costs by adding the four costs that you can specify using different units:

Cost per acre

A cost in dollars per total land area in acres.

% of Direct Cost

A cost as a percentage of **Total Direct Cost** under **Direct Capital Cost**.

Cost per Wac

A cost in dollars per AC Watt of nameplate capacity.

Fixed Cost

A fixed dollar amount

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of engineer-procure-construct costs, project-land-miscellaneous costs, and sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page.

Total Installed Cost

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow.

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Fossil Fuel Cost ($/MMBtu)

The cost per million British thermal units for fuel. SAM uses the conversion factor 1 MWh = 3.413 MMBtu. SAM calculates a fossil fuel cost for concentrating solar power systems with fossil backup, and for the generic system when the heat rate on the Power Plant page is not zero.

Note. If you are using the generic system model to represent a system that does not consume fuel, you should use a fuel cost of zero.

Entering Periodic Operation and Maintenance Costs

SAM allows you to specify any of the four operation and maintenance (O&M) cost categories on the System Costs page either as a single annual cost, or using a table of values to specify an annual schedule of costs. An annual schedule makes it possible to assign costs to particular years in the analysis period. Annual schedules can be used to account for component replacement costs and other periodic costs that do not recur on a regular annual basis.

You choose whether to specify an O&M cost as a single annual value or an annual schedule with the grey and blue button next to each variable. SAM uses the option indicated by the blue highlight on the button: A blue highlighted “Value” indicates a single, regularly occurring annual value. A blue highlighted “Sched” indicates that the value is specified as an annual schedule.

For example, to account for component replacement costs, you can specify the fixed annual cost category as an annual schedule, and assign the cost of replacing or rebuilding the component to particular years. For a 30-year project using a component with a seven-year life, you would assign a replacement cost to years seven, 14, and 21. Or, to account for expected improvements in the component's reliability in the future, you could assign component replacement costs in years seven, 17, and 27. After running simulations, you can see the replacement costs in the project cash flow in the appropriate column under Operating Expenses. SAM accounts for the operating costs in the other economic metrics including the levelized cost of energy and net present value.

Notes.

If you use the annual schedule option to specify equipment replacement costs, SAM does not calculate any residual or salvage value of system components based on the annual schedule. SAM calculates salvage value separately, using the salvage value you specify on the Financing page.

Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

The following procedure describes how to define the fixed annual cost category as an annual schedule. You can use the same procedure for any of the other operation and maintenance cost categories.

To assign component replacement costs to particular years:

1. In the Fixed Annual Cost category, note that the "Value" label of the grey and blue button is blue indicating that the single value mode is active for the variable.

   In this case, SAM would assign an annual cost of $284 to each year in the project cash flow.
2. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.

3. Click **Edit**.
4. In the Edit Schedule window, use the vertical scroll bar to find the year of the first replacement, and type the replacement cost in current or constant dollars for that year.

   To delete a value, select it and press the Delete key on your keyboard.

> **Note.** You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no annual costs.

5. When you have finished editing the schedule, click **Accept**.

Because you must specify an O&M cost category as either an annual cost or annual schedule, to assign both a recurring annual fixed cost and periodic replacement cost, you must type the recurring cost in each year of the annual schedule, and for years with replacement costs, type the sum of the recurring and replacement costs.

About the CSP Default Cost Assumptions

The default values the System Costs page for the CSP models reflect the National Renewable Energy Laboratory's best estimate of representative system costs for the United States at the time of the SAM version release. The values are based on cost studies undertaken by NREL, review of published literature, and conversations with developers and industry insiders. Costs are reviewed prior to each new SAM release.

> **Note.** Always review all of the inputs for your SAM project to determine whether they are appropriate for your analysis.

The parabolic trough and power tower costs are heavily influenced by two studies:

1. C.S. Turchi, "Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM)," NREL/TP-550-47605, 2010. (PDF 7.2 MB)
2. G. J. Kolb, C. K. Ho, T. R. Mancini, and J. A. Gary, "Power Tower Technology Roadmap and Cost Reduction Plan," SAND2011-2419, 2011. (PDF 503 KB)

These studies differed in some important assumptions. The differences in the location and cooling method assumptions for the default cases of the CSP technologies are outlined in the following table. The choice of location affects solar resource and the assumed labor costs associated with the case. Construction labor rates in Arizona tend to be lower than in California, which reduces installed costs. The trough, linear Fresnel, and generic solar systems are assumed to use evaporative cooling (i.e., a “wet” system). The power tower systems are assumed to be dry cooled. However, the cooling method is not unique to the technologies, and SAM allows the user to change the cooling system if desired. Note that if one switches power cycle cooling system, the power block costs would be expected to change. Perhaps less obvious, the site preparation costs are lower for dry-cooled systems, due to the elimination of the large blowdown evaporation ponds required with wet systems. These changes do not occur automatically in SAM; relevant system costs must be adjusted by the user.

Technology	Default Location	Default Cooling method
Physical Trough	SW Arizona (Tucson weather file)	Wet
Empirical Trough	SW Arizona (Tucson weather file)	Wet
Molten Salt Power Tower	Southern California (Daggett weather file)	Dry
Direct Steam Power Tower	Southern California (Daggett weather file)	Dry
Linear Fresnel	SW Arizona (Tucson weather file)	Wet
Dish Stirling	Arizona (Phoenix weather file)	Dry
Generic Solar	SW Arizona (Tucson weather file)	Wet

The trough, tower, and linear Fresnel models assume the “balance of plant” cost category is composed of the steam generation system. This is consistent with reference [2] above. This choice is made to allow users to highlight the effect of a direct steam generation (DSG) design. In a DSG design, the balance of plant cost category is zero because steam generation occurs in the solar receiver.

The lesser commercial activity in dish Stirling and linear Fresnel systems makes cost values for those technologies more uncertain than for troughs and towers. Dish Stirling and linear Fresnel costs are estimated based on discussions with developers and researchers.

15.7 Dish System Costs

To view the Dish System Costs page, click **Dish System Costs** on the main window's navigation menu. Note that for the dish input pages to be available, the technology option in the Technology and Market window must be Concentrating Solar Power - Dish Stirling System.

Contents

Overview

SAM uses the variables on the Dish System Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics reported in the Metrics table on the Results page.

Because only the Total Installed Cost value affects the cash flow calculations, you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the solar field to the site improvements cost category or to the engineer-procure-construct category with equivalent results. The categories are provided to help you keep track of the different costs, but do not affect the economic calculations. After assigning costs to the categories, verify that the total installed costs value is what you expect.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

CSP System Cost Notes.

The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

The direct capital costs in $/kWe are in kilowatts of gross power block capacity rather than nameplate capacity because the size and cost of the power block is determined by the gross capacity, not the net capacity. The total installed cost in $/kWe (actually overnight installed cost because it does not include financing during construction costs, which are accounted for on the Financing page) is in kilowatts of nameplate capacity, because that is what is delivered to the grid and is consistent with how costs are reported for utility generation technologies. The indirect costs in $/Wac are in Watts of nameplate power block capacity because those costs that use the entire plant as the basis, not just the power block.

Input Variable Reference

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

Note: Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

Site Improvements ($/m2)

A cost per square meter of solar field area to account for expenses related to site preparation and other equipment not included in the solar field cost category.

Collector Cost (Projected Area) ($/m2)

A cost per square meter of projected mirror area from the Collector page to account for expenses related to installation of the collectors, including labor and equipment.

Receiver Cost ($/kW)

A cost per kW of engine rated capacity from the Stirling Engine page to account for expenses related to installation of the receiver, including labor and equipment.

Engine Cost ($/kW)

Cost per kW of engine rated capacity from the Stirling Engine page to account for expenses related to installation of the Stirling engine components, including labor and equipment.

Contingency (%)

A percentage of the sum of the site improvements, solar field, HTF system, storage, fossil backup, and power plant costs to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of site improvements, collector cost, receiver cost, engine cost, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

Note: Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

Total Land Area

The total land area required for the project, from the Solar Field or Heliostat Field page.

Nameplate

The system's nameplate capacity from the Power Block or Power Cycle page.

EPC and Owner Costs

EPC (engineer-procure-construct) and owner costs are associated with the design and construction of the project. SAM calculates the total cost as the sum of the Non-fixed Cost and Fixed Cost.

Typical costs that may be appropriate to include in the EPC and Owner category are: Permitting, royalty payments, consulting, management or legal fees, geotechnical and environmental surveys, interconnection costs, spare parts inventories, commissioning costs, and the owner's engineering and project development activities.

Total Land Costs

Costs associated with land purchases, which SAM calculates as the sum of a non-fixed cost and a fixed cost. Use the Land category described below for land costs, and inputs on the Financing page for financing costs.

Units for Land and EPC Costs

SAM calculates the total EPC and Owner Costs and Total Land Costs by adding the four costs that you can specify using different units:

Cost per acre

A cost in dollars per total land area in acres.

% of Direct Cost

A cost as a percentage of **Total Direct Cost** under **Direct Capital Cost**.

Cost per Wac

A cost in dollars per AC Watt of nameplate capacity.

Fixed Cost

A fixed dollar amount

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of engineer-procure-construct costs, project-land-miscellaneous costs, and sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page.

Total Installed Cost

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow in Years 1 and later..

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Entering Periodic Operation and Maintenance Costs

SAM allows you to specify any of the four operation and maintenance (O&M) cost categories on the System Costs page either as a single annual cost, or using a table of values to specify an annual schedule of costs. An annual schedule makes it possible to assign costs to particular years in the analysis period. Annual schedules can be used to account for component replacement costs and other periodic costs that do not recur on a regular annual basis.

You choose whether to specify an O&M cost as a single annual value or an annual schedule with the grey and blue button next to each variable. SAM uses the option indicated by the blue highlight on the button: A blue highlighted “Value” indicates a single, regularly occurring annual value. A blue highlighted “Sched” indicates that the value is specified as an annual schedule.

For example, to account for component replacement costs, you can specify the fixed annual cost category as an annual schedule, and assign the cost of replacing or rebuilding the component to particular years. For a 30-year project using a component with a seven-year life, you would assign a replacement cost to years seven, 14, and 21. Or, to account for expected improvements in the component's reliability in the future, you could assign component replacement costs in years seven, 17, and 27. After running simulations, you can see the replacement costs in the project cash flow in the appropriate column under Operating Expenses. SAM accounts for the operating costs in the other economic metrics including the levelized cost of energy and net present value.

Notes.

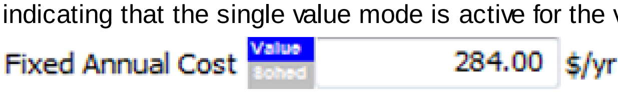
If you use the annual schedule option to specify equipment replacement costs, SAM does not calculate any residual or salvage value of system components based on the annual schedule. SAM calculates salvage value separately, using the salvage value you specify on the Financing page.

Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

The following procedure describes how to define the fixed annual cost category as an annual schedule. You can use the same procedure for any of the other operation and maintenance cost categories.

To assign component replacement costs to particular years:

1. In the Fixed Annual Cost category, note that the "Value" label of the grey and blue button is blue indicating that the single value mode is active for the variable.



In this case, SAM would assign an annual cost of $284 to each year in the project cash flow.

2. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.

3. Click **Edit**.
4. In the Edit Schedule window, use the vertical scroll bar to find the year of the first replacement, and type the replacement cost in current or constant dollars for that year.

   To delete a value, select it and press the Delete key on your keyboard.

Note. You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no annual costs.

5. When you have finished editing the schedule, click **Accept**.

Because you must specify an O&M cost category as either an annual cost or annual schedule, to assign both a recurring annual fixed cost and periodic replacement cost, you must type the recurring cost in each year of the annual schedule, and for years with replacement costs, type the sum of the recurring and replacement costs.

About the CSP Default Cost Assumptions

The default values the System Costs page for the CSP models reflect the National Renewable Energy Laboratory's best estimate of representative system costs for the United States at the time of the SAM version release. The values are based on cost studies undertaken by NREL, review of published literature, and conversations with developers and industry insiders. Costs are reviewed prior to each new SAM release.

Note. Always review all of the inputs for your SAM project to determine whether they are appropriate for your analysis.

The parabolic trough and power tower costs are heavily influenced by two studies:

1. C.S. Turchi, "Parabolic Trough Reference Plant for Cost Modeling with the Solar Advisor Model (SAM)," NREL/TP-550-47605, 2010. (PDF 7.2 MB)
2. G. J. Kolb, C. K. Ho, T. R. Mancini, and J. A. Gary, "Power Tower Technology Roadmap and Cost Reduction Plan," SAND2011-2419, 2011. (PDF 503 KB)

These studies differed in some important assumptions. The differences in the location and cooling method assumptions for the default cases of the CSP technologies are outlined in the following table. The choice of location affects solar resource and the assumed labor costs associated with the case. Construction labor rates in Arizona tend to be lower than in California, which reduces installed costs. The trough, linear Fresnel, and generic solar systems are assumed to use evaporative cooling (i.e., a “wet” system). The power tower systems are assumed to be dry cooled. However, the cooling method is not unique to the technologies, and SAM allows the user to change the cooling system if desired. Note that if one switches power cycle cooling system, the power block costs would be expected to change. Perhaps less obvious, the site preparation costs are lower for dry-cooled systems, due to the elimination of the large blowdown evaporation ponds required with wet systems. These changes do not occur automatically in SAM; relevant system costs must be adjusted by the user.

Technology	Default Location	Default Cooling method
Physical Trough	SW Arizona (Tucson weather file)	Wet
Empirical Trough	SW Arizona (Tucson weather file)	Wet
Molten Salt Power Tower	Southern California (Daggett weather file)	Dry
Direct Steam Power Tower	Southern California (Daggett weather file)	Dry
Linear Fresnel	SW Arizona (Tucson weather file)	Wet
Dish Stirling	Arizona (Phoenix weather file)	Dry
Generic Solar	SW Arizona (Tucson weather file)	Wet

The trough, tower, and linear Fresnel models assume the "balance of plant" cost category is composed of the steam generation system. This is consistent with reference [2] above. This choice is made to allow users to highlight the effect of a direct steam generation (DSG) design. In a DSG design, the balance of plant cost category is zero because steam generation occurs in the solar receiver.

The lesser commercial activity in dish Stirling and linear Fresnel systems makes cost values for those technologies more uncertain than for troughs and towers. Dish Stirling and linear Fresnel costs are estimated based on discussions with developers and researchers.

15.8 Generic Solar System Costs

CSP System Cost Notes.

The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

The direct capital costs in $/kWe are in kilowatts of gross power block capacity rather than nameplate capacity because the size and cost of the power block is determined by the gross capacity, not the net capacity. The total installed cost in $/kWe (actually overnight installed cost because it does not include financing during construction costs, which are accounted for on the Financing page) is in kilowatts of nameplate capacity, because that is what is delivered to the grid and is consistent with how costs are reported for utility generation technologies. The indirect costs in $/Wac are in Watts of nameplate power block capacity because those costs that use the entire plant as the basis, not just the power block.

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

Note: Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

Site Improvements ($/m^2)

A cost per square meter of solar field area to account for expenses related to site preparation and other equipment not included in the solar field cost category.

Solar Field ($/m^2)

A cost per square meter of solar field area to account for expenses related to installation of the solar field, including labor and equipment.

Storage ($/kWht)

Cost per thermal megawatt-hour of storage capacity to account for expenses related to installation of the thermal storage system, including equipment and labor.

Fossil Backup ($/kWe)

Cost per electric megawatt of power block gross capacity to account for the installation of a fossil backup system, including equipment and labor.

Power Plant ($/kWe)

Cost per electric megawatt of power block gross capacity to account for the installation of the power block, including equipment and labor.

Balance of Plant ($/kWe)

Cost per electric megawatt of power block gross capacity to account for additional costs.

Contingency (%)

A percentage of the sum of the site improvements, solar field, HTF system, storage, fossil backup, and power plant costs to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of improvements, solar field, HTF system, storage, fossil backup, power plant costs, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

Note: Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

Total Land Area

The total land area required for the project, from the Solar Field or Heliostat Field page.

Nameplate

The system's nameplate capacity from the Power Block or Power Cycle page.

EPC and Owner Costs

EPC (engineer-procure-construct) and owner costs are associated with the design and construction of the project. SAM calculates the total cost as the sum of the Non-fixed Cost and Fixed Cost.

Typical costs that may be appropriate to include in the EPC and Owner category are: Permitting, royalty payments, consulting, management or legal fees, geotechnical and environmental surveys, interconnection costs, spare parts inventories, commissioning costs, and the owner's engineering and project development activities.

Total Land Costs

Costs associated with land purchases, which SAM calculates as the sum of a non-fixed cost and a fixed cost. Use the Land category described below for land costs, and inputs on the Financing page for financing costs.

Units for Land and EPC Costs

SAM calculates the total EPC and Owner Costs and Total Land Costs by adding the four costs that you can specify using different units:

Cost per acre

A cost in dollars per total land area in acres.

% of Direct Cost

A cost as a percentage of **Total Direct Cost** under **Direct Capital Cost**.

Cost per Wac

A cost in dollars per AC Watt of nameplate capacity.

Fixed Cost

A fixed dollar amount

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of engineer-procure-construct costs, project-land-miscellaneous costs, and sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page.

Total Installed Cost

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow.

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Fossil Fuel Cost ($/MMBtu)

The cost per million British thermal units for fuel. SAM uses the conversion factor 1 MWh = 3.413 MMBtu. SAM calculates a fossil fuel cost for concentrating solar power systems with fossil backup, and for the generic system when the heat rate on the Power Plant page is not zero.

> **Note.** If you are using the generic system model to represent a system that does not consume fuel, you should use a fuel cost of zero.

15.9 Generic System Costs

To view the Generic System Costs page, click **Generic System Costs** on the main window's navigation menu. Note that for the generic system input pages to be available, the technology option in the Technology and Market window must be Generic System.

Contents

- Overview describes the Generic System Costs page and explains where to find more information.
- Input Variable Reference describes the input variables on the Generic System

Costs page.

- [Entering Periodic Operation and Maintenance Costs] explains how to use annual schedules to assign operation and maintenance costs to particular years in the project cash flow.

Overview

SAM uses the variables on the Generic System Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics reported in the Metrics table on the Results page.

Because only the Total Installed Cost value affects the cash flow calculations, you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the power plant to the direct plant cost category or to the engineer-procure-construct category with equivalent results. The categories are provided to help you keep track of the different costs, but do not affect the economic calculations. After assigning costs to the categories, verify that the total installed costs value is what you expect.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

Note. The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

Input Variable Reference

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

Note: Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

System size (kW)

The **Nameplate Capacity** from the Power Plant page.

Cost per watt ($/W)

A cost per Watt of nameplate capacity.

Fixed Plant Cost ($)

A fixed dollar amount.

Non-fixed System Cost ($)

The product of the Cost per Watt cost category and the nameplate capacity.

Contingency (%)

A percentage of the fixed plant cost and non-fixed system cost to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of fixed plant cost, non-fixed system cost, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

Note: Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

Engineer, Procure, Construct (% and $)

Engineer-procure-construct costs, sometimes abbreviated as EPC costs, are costs associated with the design and construction of the project, which SAM calculates as the sum of a "non-fixed cost" and a fixed cost.

% of Direct Cost is a value that you type as a percentage of **Total Direct Cost** (under **Direct Capital Cost**).

Non-fixed Cost is the product of **% of Direct Cost** and **Total Direct Cost**.

Fixed Cost is a value that you type as a fixed amount in dollars.

The total engineer-procure-construct cost is the sum of **Non-fixed Cost** and **Fixed Cost**.

Project, Land, Miscellaneous (% and $)

Costs associated with land purchases, permitting, and other costs which SAM calculates as the sum of a "non-fixed cost" and a fixed cost.

% of Direct Cost is a value that you type as a percentage of **Total Direct Cost** (under **Direct Capital Cost**).

Non-fixed Cost is the product of **% of Direct Cost** and **Total Direct Cost**.

Fixed Cost is a value that you type as a fixed amount in dollars.

The total project-land-miscellaneous cost is the sum of **Non-fixed Cost** and **Fixed Cost**.

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of engineer-procure-construct costs, project-land-miscellaneous costs, and sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page.

Total Installed Cost ($)

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow.

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** rate specified on the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Fossil Fuel Cost ($/MMBtu)

The cost per million British thermal units for fuel. SAM uses the conversion factor 1 MWh = 3.413 MMBtu. The fuel cost only applies to generic system, parabolic trough, and power tower systems. Although the photovoltaic and dish-Stirling models ignore the fuel cost input variable, you should specify a value of zero for the variable to avoid confusion. (When the fossil fill fraction variable on the Thermal Storage page for either of the parabolic trough models or the power tower model is greater than zero, the systems may consume fuel for backup energy.)

Entering Periodic Operation and Maintenance Costs

SAM allows you to specify any of the four operation and maintenance (O&M) cost categories on the System

Costs page either as a single annual cost, or using a table of values to specify an annual schedule of costs. An annual schedule makes it possible to assign costs to particular years in the analysis period. Annual schedules can be used to account for component replacement costs and other periodic costs that do not recur on a regular annual basis.

You choose whether to specify an O&M cost as a single annual value or an annual schedule with the grey and blue button next to each variable. SAM uses the option indicated by the blue highlight on the button: A blue highlighted “Value” indicates a single, regularly occurring annual value. A blue highlighted “Sched” indicates that the value is specified as an annual schedule.

For example, to account for component replacement costs, you can specify the fixed annual cost category as an annual schedule, and assign the cost of replacing or rebuilding the component to particular years. For a 30-year project using a component with a seven-year life, you would assign a replacement cost to years seven, 14, and 21. Or, to account for expected improvements in the component's reliability in the future, you could assign component replacement costs in years seven, 17, and 27. After running simulations, you can see the replacement costs in the project cash flow in the appropriate column under Operating Expenses. SAM accounts for the operating costs in the other economic metrics including the levelized cost of energy and net present value.

> **Notes.**
>
> If you use the annual schedule option to specify equipment replacement costs, SAM does not calculate any residual or salvage value of system components based on the annual schedule. SAM calculates salvage value separately, using the salvage value you specify on the Financing page.
>
> Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

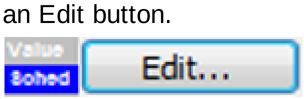
The following procedure describes how to define the fixed annual cost category as an annual schedule. You can use the same procedure for any of the other operation and maintenance cost categories.

To assign component replacement costs to particular years:

1. In the Fixed Annual Cost category, note that the "Value" label of the grey and blue button is blue indicating that the single value mode is active for the variable.

   In this case, SAM would assign an annual cost of $284 to each year in the project cash flow.
2. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.

3. Click **Edit**.
4. In the Edit Schedule window, use the vertical scroll bar to find the year of the first replacement, and type the replacement cost in current or constant dollars for that year.

   To delete a value, select it and press the Delete key on your keyboard.

> **Note.** You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no annual costs.

5. When you have finished editing the schedule, click **Accept**.

Because you must specify an O&M cost category as either an annual cost or annual schedule, to assign both a recurring annual fixed cost and periodic replacement cost, you must type the recurring cost in each year of the annual schedule, and for years with replacement costs, type the sum of the recurring and replacement costs.

15.10 SWH System Costs

To view the SWH System Costs page, click **SWH System Costs** on the main window's navigation menu. Note that for the solar water heating system input pages to be available, the technology option in the Technology and Market window must be BeOpt/TRNSYS Solar Water Heating Model.

Contents

Overview

SAM uses the variables on the SWH System Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

The SWH System Costs page is divided into four main categories. The first two, Direct Capital Costs and Indirect Capital Costs, are summed in the third category, Total Installed Costs. Because only the Total Installed Cost value affects the cash flow calculations, you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the collector to the collector cost category or to the engineer-procure-construct category with equivalent results. The categories are provided to help you keep track of the different costs, but do not affect the economic calculations. After assigning costs to the categories, verify that the total installed costs value is what you expect. The fourth category of costs covers Operation and Maintenance.

Note. The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

Input Variable Reference

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

> **Note:** Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

Collector Cost ($/m^2, $/Unit, or $/W)

The cost of collectors in the system. You can either include labor costs for collector installation in the collector cost, or account for it separately using the installation cost category. The total collector cost is calculated as either:

- Dollars per square meter multiplied by collector area on the SWH System page, or
- Dollars per unit, representing the total collector cost, or
- Dollars per thermal watt of collector capacity multiplied by the nameplate capacity on the SWH System page.

Storage Cost ($/m^3 or $/Unit)

The cost of the solar storage tanks. The total storage cost is either:

- Dollars per cubic meters multiplied by the storage volume on the SWH System page, or
- Dollars per unit, representing the total storage cost.

Balance of System ($)

A fixed cost that can be used to account for costs not included in the collector and storage cost categories, for example, the mounting racks and piping.

Installation Cost ($)

A fixed cost that can be used to account for labor or other costs not included in the other cost categories.

Contingency (%)

A percentage of the sum of the collector, storage, balance of system, and installation costs to account for expected uncertainties in direct cost estimates.

Total Direct Cost ($)

The sum of collector, storage, balance of system, installation, and contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

> **Note:** Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

Engineer, Procure, Construct (% and $)

Engineer-procure-construct costs, sometimes abbreviated as EPC costs, are costs associated with the design and construction of the project, which SAM calculates as the sum of a "non-fixed cost" and a fixed cost.

% of Direct Cost is a value that you type as a percentage of **Total Direct Cost** (under **Direct Capital Cost**).

Non-fixed Cost is the product of **% of Direct Cost** and **Total Direct Cost**.

Fixed Cost is a value that you type as a fixed amount in dollars.

The total engineer-procure-construct cost is the sum of **Non-fixed Cost** and **Fixed Cost**.

Project, Land, Maintenance (% and $)

Costs associated with land purchases, permitting, and other costs which SAM calculates as the sum of a "non-fixed cost" and a fixed cost.

SAM does not use the land area value shown on the solar field page for trough and tower systems in the land cost calculation.

% of Direct Cost is a value that you type as a percentage of **Total Direct Cost** (under **Direct Capital Cost**).

Non-fixed Cost is the product of **% of Direct Cost** and **Total Direct Cost**.

Fixed Cost is a value that you type as a fixed amount in dollars.

The total project-land-miscellaneous cost is the sum of **Non-fixed Cost** and **Fixed Cost**.

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of engineer-procure-construct costs, project-land-miscellaneous costs, and sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page and Depreciation pages.

Total Installed Cost ($)

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow in Years 1 and later..

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

Entering Periodic Costs

SAM allows you to specify any of the four operation and maintenance (O&M) cost categories on the System Costs page either as a single annual cost, or using a table of values to specify an annual schedule of costs. An annual schedule makes it possible to assign costs to particular years in the analysis period. Annual schedules can be used to account for component replacement costs and other periodic costs that do not recur on a regular annual basis.

You choose whether to specify an O&M cost as a single annual value or an annual schedule with the grey and blue button next to each variable. SAM uses the option indicated by the blue highlight on the button: A blue highlighted “Value” indicates a single, regularly occurring annual value. A blue highlighted “Sched” indicates that the value is specified as an annual schedule.

For example, to account for component replacement costs, you can specify the fixed annual cost category as an annual schedule, and assign the cost of replacing or rebuilding the component to particular years. For a 30-year project using a component with a seven-year life, you would assign a replacement cost to years seven, 14, and 21. Or, to account for expected improvements in the component's reliability in the future, you could assign component replacement costs in years seven, 17, and 27. After running simulations, you can see the replacement costs in the project cash flow in the appropriate column under Operating Expenses. SAM accounts for the operating costs in the other economic metrics including the levelized cost of energy and net present value.

Notes.

If you use the annual schedule option to specify equipment replacement costs, SAM does not calculate any residual or salvage value of system components based on the annual schedule. SAM calculates salvage value separately, using the salvage value you specify on the Financing page.

Dollar values in the annual schedule are in nominal or current dollars. SAM does not apply inflation and escalation rates to values in annual schedules.

The following procedure describes how to define the fixed annual cost category as an annual schedule. You can use the same procedure for any of the other operation and maintenance cost categories.

To assign component replacement costs to particular years:

1. In the Fixed Annual Cost category, note that the "Value" label of the grey and blue button is blue indicating that the single value mode is active for the variable.

   In this case, SAM would assign an annual cost of $284 to each year in the project cash flow.
2. Click the button so that "Sched" label is highlighted in blue. SAM replaces the variable's value with an Edit button.

3. Click **Edit**.
4. In the Edit Schedule window, use the vertical scroll bar to find the year of the first replacement, and type the replacement cost in current or constant dollars for that year.

   To delete a value, select it and press the Delete key on your keyboard.

Note. You must type a value for each year. If you delete a value, SAM will clear the cell, and you must type a number in the cell or SAM will consider the schedule to be invalid. Type a zero for years with no annual costs.

5. When you have finished editing the schedule, click **Accept**.

Because you must specify an O&M cost category as either an annual cost or annual schedule, to assign both a recurring annual fixed cost and periodic replacement cost, you must type the recurring cost in each year of the annual schedule, and for years with replacement costs, type the sum of the recurring and replacement costs.

15.1 Wind System Costs
1

The Wind System Costs page allows you to specify the costs of a wind power project.

Note. The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

NREL Capital Cost Model

The default capital cost values are from the NREL Capital Cost model, which has a different set of cost assumptions for land-based and offshore wind farms. You can populate the default values with costs for each type of wind farm.

Land-based installation

Choose this option to use default capital cost values from the NREL Capital Cost Model for land-based wind farms.

When you choose the **Define the turbine characteristics below** option on the Turbine page, you can choose **Automatically estimate land-based costs** to allow SAM to calculate capital cost values based on the wind turbine characteristics.

Shallow offshore installation (<30m)

Choose this option to use default values for offshore wind farms.

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow.

Note: Because SAM uses only the Total Installed Cost value in cash flow calculations, how you distribute costs among the different direct capital cost categories does not affect the final results.

For each direct cost category, you can specify the cost in $/kW of wind farm capacity, a fixed cost in $, or a cost per turbine in $/turbine. If you specify more than one cost, for example a foundation cost in both $/kW and $/turbine, SAM adds the values together to calculate the total category cost.

Turbine Cost

The cost of a single turbine.

Foundations

Material, labor, and other costs associated with building turbine foundations for the entire wind farm.

Electrical Infrastructure

Wiring, transformer, and other costs associated with electrical equipment on the wind farm.

Contingency (%)

A percentage of the sum of the total turbine, foundations, and electrical infrastructure costs, that you can use to account for expected uncertainties in direct cost estimates.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

> **Note:** Because SAM uses only the total installed cost value in cash flow calculations, how you distribute costs among the different indirect capital cost categories does not affect the final results.

You can specify each indirect capital cost category as a cost per kW of wind farm capacity, fixed cost, or percentage of the total direct cost. If you assign more than one cost to a category, for example a $/kW and fixed amount for the Transportation and Installation category, SAM adds the values to calculate the total Transportation and Installation amount.

Engineer, Procure, Construct

Engineer-procure-construct costs, sometimes abbreviated as EPC costs, are costs associated with the design and construction of the project.

Project, Land, Miscellaneous

Costs associated with land purchases, permitting, and other costs.

Transportation and Installation

Costs associated with transporting and installing turbine equipment.

Ports, Staging, Scour, etc (offshore farms)

Offshore wind farm costs associated with transporting turbines from land to the project site.

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of the four indirect cost categories.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate incentive amounts for investment-based incentives defined on the Incentives page and depreciation amounts on the Depreciation page.

Total Installed Cost ($)

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow in Years 1 and later..

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

15.1 2 Geothermal System Costs

As will all of the SAM models, the cost page is used to calculate a total installed cost and an operating cost for use in the financial models. The inputs on this page do not impact the performance of the system.

> **Note.** The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

This is an overview of the geothermal cost inputs (which come from the GETEM model). For more details of how geothermal system costs are specified in the SAM's geothermal model, see the following sections of the GETEM documentation at the following link: http://www1.eere.energy.gov/geothermal/getem_manuals.html.

From the GETEM Guide to Providing Input to the Model, May 2011:

Model Input

Pages 10-22

Binary

Section 4.1.c on page A-11

Section 4.1.g on page A-15

Flash

Section 5.2.a on page A-20

Number of Wells to Drill

GETEM calculates the number of production wells necessary based on inputs on the Plant and Equipment page. Based on the number of production wells required, you can specify how many wells have to be drilled in this section.

Because confirmation wells can sometimes be used for production, this section has an input to specify what portion of the confirmation wells will be used on this way. The number of confirmation wells that will be used for production is calculated by multiplying the number of confirmation wells (entered in the "Drilling and Associated Costs" section) by the "% of Confirmation Wells Used for Production" and is shown in the "Number of Confirmation Wells" textbox.

The rest of the production wells have to be drilled and will incur the production well drilling cost. The number of production wells that will have to be drilled is calculated by subtracting the production wells to be drilled from the total production wells required and is shown in the "Number of Production Wells to be Drilled" textbox.

The number of injection wells is typically a function of the number of production wells. You can specify this ration in the "Ratio of Injection Wells to Production Wells" input. (Keep in mind that the ratio is the injection wells to the total number of production wells, not the number of production wells that have to be drilled.) This value will be multiplied by the "Total Production Wells Required" value to calculate the "Number of Injection Wells to be Drilled."

Drilling and associated costs

Exploration and Confirmation

The cost for exploration and confirmation wells is expressed as a function of the cost of a production well. The "Cost multiplier" column is multiplied by the production well cost to calculate the "Cost per well." This value is multiplied by the "# of wells" input to calculated the "Drilling cost". You can specify other costs for exploration and confirmation in the "Non-drilling cost" column, which will be added to the "Drilling cost" to calculate the total.

Production and Injection

Production and injection drilling costs are specified as a function of the depth of the wells. The well depth is assumed to be the resource depth, specified on the Resource input page. The drilling cost per well is calculated using the depth and the chosen cost curve, which is a function relating well depth to cost. The 3 Cost Curves (Low, Medium, and High) bracket the Sandia National Laboratories drilling data (see GETEM reference manuals for details). The cost per well for production and injection wells (derived from the depth and the cost curve) is shown in the "Cost per well" column. The number of wells shown in the "# of wells" column comes from the values in the "Number of Wells to Drill" section above. The "Drilling cost" is calculated by multiplying the "# of wells" by the "Cost per well." The total number of wells and drilling cost is displayed below the Production and Injection wells. You can specify non-drilling costs in this row, which will be added to the drilling cost, to calculate the total cost for production and injection wells.

Surface Equipment, Installation and Stimulation Cost

Surface equipment and well stimulation costs are assumed to be a function of the total number of production and injection wells. The value entered in the "Cost per well" column will be multiplied by the value in the "# of wells" column to calculate the total, shown in the "Non-drilling cost" column.

Over-riding calculated costs

You can choose to override drilling and associated cost calculations and enter their own cost. If the "Calculate" box is unchecked, the total for the section will be the value entered in the "Specified Total Drilling, Surface Equipment, and Stimulation Cost" input.

Plant Capital Cost

The plant capital costs are entered on a "per Kw" basis, meaning that you enter the dollars per kilowatt, and SAM will multiply this by the size of the unit (from the "Plant and Equipment" input page) to calculate the Power Plant Cost.

The calculated value can be over-ridden by un-checking the "Calculated" checkbox and entering a value in the "Specified Plant Cost" input.

Pump Cost Inputs

The pump costs are entered as a function of the pump depth and pump size (calculated on the Plant and Equipment input page). The installation and casing cost is specified on a per foot basis and multiplied by the calculated pump depth to determine the total cost. Pump cost is specified on a per horsepower basis and is multiplied by a function of the pump size to determine the cost per pump.

The total installed cost per pump is the sum of the pump cost and the installation and casing cost. This is multiplied by the total number of production wells required to calculate the total pump cost.

The calculated value can be over-ridden by un-checking the "Calculated" checkbox and entering a value in the "Specified Pump Cost" input.

Recapitalization Cost

The recapitalization cost will be added each time the resource has to be re-drilled to reach a new section of the geothermal resource in order to increase the production well temperature. Recapitalization costs can be specified directly, or calculated by checking the "Calculate" checkbox. The calculated value is the sum of confirmation, production, and injection drilling costs (excluding non-drilling costs), the surface equipment and installation cost, and the total pump costs.

Total Installed Costs

The total installed cost for the project is the sum of the direct and indirect capital costs. The direct capital cost is the sum of the drilling, plant and pump costs, with a contingency percentage added on. The indirect capital cost is calculated in the "Indirect Capital Costs" section.

Indirect Capital Costs

Indirect capital costs are broken down into three types: engineering, procurement, and construction; project, land, and misc; and sales tax. The first two can be entered as a percentage of direct costs, as a stand alone value, or both (which will be summed to calculate a total). The sales tax percentage is entered on the Financing page and is applied to some portion of the direct cost. These three types of indirect costs are summed to calculated the total indirect cost.

The calculated value can be over-ridden by un-checking the "Calculated" checkbox and entering a value in the "Specified Indirect Cost" input.

15.1 3 Co-Production Costs

Geothermal co-production costs are divided into two categories: Direct capital costs, and other costs. The direct capital costs are entered on a per KW basis, meaning that you enter the cost in dollars per kilowatt, and SAM multiplies this by the size of the unit (entered on the "Resource and Power Generation" input page) to calculate the Installed Plant Cost.

Note. The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

Other costs represent indirect costs associated with the project: legal, permitting, etc. These costs are simply summed, and added to the Installed Plant Cost to calculate the Total Installed Cost.

For questions about the Co-Production model please email SAM support at sam.support@nrel.gov.

15.1 4 Biopower System Costs

SAM uses the variables on the Biopower System Costs page to calculate the project investment cost and annual operating costs reported in the project cash flow and used to calculate cost metrics reported in the Metrics table on the Results page.

Note. The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

Because only the **Total Installed Cost** value affects the cash flow calculations, you can assign capital costs to the different cost categories in whatever way makes sense for your analysis. For example, you could assign the cost of designing the power plant to the direct plant cost category or to the engineer-procure-construct category with equivalent results. The categories are provided to help you keep track of the different costs, but do not affect the economic calculations. After assigning costs to the categories, verify that the total installed costs value is what you expect.

Variable values in boxes with white backgrounds are values that you can edit. Boxes with blue backgrounds contain calculated values or values from other pages that SAM displays for your information.

Direct Capital Costs

A direct capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow. Below are the major unit operations that contribute to the Total Direct Capital Cost calculation, and the appropriate units. Based on earlier inputs, SAM calculates the capacity of each item.

Boiler(s)

A cost per lb/hr steam

Turbine & Generator

A cost per kW of gross nameplate capacity to account for turbine and generator installation costs.

Fuel Handling Equipment

A cost per kW of gross nameplate capacity to account for fuel handling equipment costs.

Dryer

A cost per kW of gross nameplate capacity to account for feedstock drying equipment. This cost is only available when you choose **Dry to Specified Moisture Content** as the Biomass Feedstock Handling option on the Plant Specs page.

Other Equipment

A cost per kW of gross nameplate capacity to account for equipment not included in the categories above.

Balance of Plant

A cost per kW of gross nameplate capacity to account for plant-related costs not associated with specific components of the plant.

Contingency

A percentage of the sum of the above costs to account for expected uncertainties in direct cost estimates.

Total Direct Capital Cost ($)

The sum of the direct capital costs, including contingency costs.

Indirect Capital Costs

An indirect cost is typically one that cannot be identified with a specific piece of equipment or installation service.

Engineer, Procure, Construct (% and $)

Engineer-Procure-Construct costs, sometimes abbreviated as EPC costs, are costs associated with the design and construction of the project, which SAM calculates as the sum of a “non-fixed cost” and with a fixed cost.

Project, Land, Miscellaneous (% and $)

Project-Land-Miscellaneous costs are those associated with the purchase and preparation of land, and other indirect costs not included in the EPC category.

% of Direct Cost

A value that you type as a percentage of **Total Direct Capital Cost** (under **Direct Capital Costs**)

Non-fixed Cost

A value that SAM calculates as the product of **% of Direct Cost** and **Total Direct Capital Cost**.

Fixed Cost

A value that you type as a fixed amount in dollars.

Total

A value that SAM calculates as the sum of **Non-fixed Cost** and **Fixed Cost**.

Sales Tax (%)

SAM calculates the total sales tax amount by multiplying the sales tax rate that you specify on the Financing page by the percentage of direct costs you specify on the System Costs page:

Total Sales Tax = Sales Tax Rate × Percentage of Direct Cost × Direct Cost

For an explanation of the effect of sales tax on income tax, see **Sales Tax** on the Financing page topic for the financial model you are using (Residential, Commercial, Utility IPP, Single Owner, etc.)

Total Indirect Cost ($)

The sum of engineer-procure-construct costs, project-land-miscellaneous costs, and sales tax.

Total Installed Cost

The total installed cost is the project's investment cost that applies in year zero of the project cash flow. SAM uses this value to calculate loan amounts and debt interest payments based on inputs on the Financing page, and to calculate tax credit and incentive payment for incentive based tax credits and incentives defined on the Incentives page and Depreciation pages.

Total Installed Cost ($)

The sum of total direct cost and total indirect cost.

Total Installed Cost per Capacity ($/Wdc or $/kW)

Total installed cost divided by the total system rated or nameplate capacity. This value is provided for reference only. SAM does not use it in cash flow calculations.

Operation and Maintenance Costs

Operation and Maintenance (O&M) costs represent annual expenditures on equipment and services that occur after the system is installed. SAM allows you to enter O&M costs in three ways: Fixed annual, fixed by capacity, and variable by generation. O&M costs are reported on the project cash flow in Years 1 and later..

For each O&M cost category, you can specify an optional annual **Escalation Rate** to represent an expected annual increase in O&M cost above the annual inflation rate specified on the Financing page. For an escalation rate of zero, the O&M cost in years two and later is the year one cost adjusted for inflation. For a non-zero escalation rate, the O&M cost in years two and later is the year one cost adjusted for inflation plus escalation.

For expenses such as component replacements that occur in particular years, you can use an annual schedule to assign costs to individual years. See below for details.

Fixed Annual Cost ($/yr)

A fixed annual cost that applied to each year in the project cash flow.

Fixed Cost by Capacity ($/kW-yr)

A fixed annual cost proportional to the system's rated or nameplate capacity.

Variable Cost by Generation ($/MWh)

A variable annual cost proportional to the system's total annual electrical output in AC megawatt-hours. The annual energy output depends on either the performance model's calculated first year value and the **Year-to-year decline in output** value from the Performance Adjustment page, or on an annual schedule of costs, depending on the option chosen.

15.1 5 Biopower Feedstock Costs

Biomass feedstock costs vary widely over distance, season, geographical location, type, and availability. Additionally, feedstock cost is traditionally a very substantial cost of every kilowatt-hour generated from biopower. The defaults are averages of several recent costs but may not be appropriate for your analysis.

> **Note.** The default cost values that appear when you create a file or case are intended to illustrate SAM's use. The cost data are meant to be realistic, but not to represent actual costs for a specific project. For more information and a list of online resources for cost data, see the SAM website, https://sam.nrel.gov/cost.

Transportation Costs

Transporting biomass differs from transporting fossil fuels in two ways. First of all, biomass has a significantly lower energy density and generally higher moisture contents. Additionally, biomass feedstocks are more distributed than fossil fuels, which are largely collected from extraction points such as mines or wells. Since long-distance biomass transportation is currently unfeasible, most biomass is delivered via diesel trucks. At larger distances, railway transport may become more cost effective.

Distance-fixed delivery cost

A distance-fixed delivery cost includes expenses incurred that are not dependent on the distance traveled. For example, this category may include the expense associated with the vehicle itself, as well as loading and unloading costs.

Distance-variable delivery cost

The distance-variable delivery cost is expressed in terms of $/ton-mi which directly reports the cost of hauling a ton of biomass as harvested for one mile. This could include vehicle maintenance costs and fuel expenditures which directly correlate to miles traveled.

Feedstock Price ($/dry ton)

The feedstock price is simply the cost of one ton of dry biomass. Note, the transportation cost is separate.

Fuel Escalation Rate (%/year)

The anticipated fuel price escalation rate can be specified separately for both biomass and coal feedstocks.

16 Results

SAM displays tables and graphs of results from the performance and financial models on the Results page.

For a general description of the Results page with screenshots, see the Getting Started topic Results Page.

For instructions for displaying data on the Results page, see:

- Metrics Table
- Graphs
- Tables
- Cash Flows
- Time Series

For detailed descriptions of variables shown in the Results page tables and graphs, see

- Metrics Table Variables
- Cash Flow Variables
- Performance Model Outputs
- Time Dependent Pricing Overview

16.1 Metrics Table

The Metrics table on the Results page displays a selected set of results variables for each case in the project file.

For a list and descriptions of the variables in the Metrics table, see

- Financial Metrics Overview for metrics from the financial models, such as LCOE, payback period, IRR, etc..
- Performance Metrics Overview for metrics from the performance models, such as annual energy, capacity factor, etc.

SAM displays the Metrics table under the navigation menu when results are available for a case. The variables that appear in the metrics table depend on the technology and financing options.

> **Note.** Values like *sv.npv* or *[not found]* indicate that there are no results to display. Try running simulations to display the values.

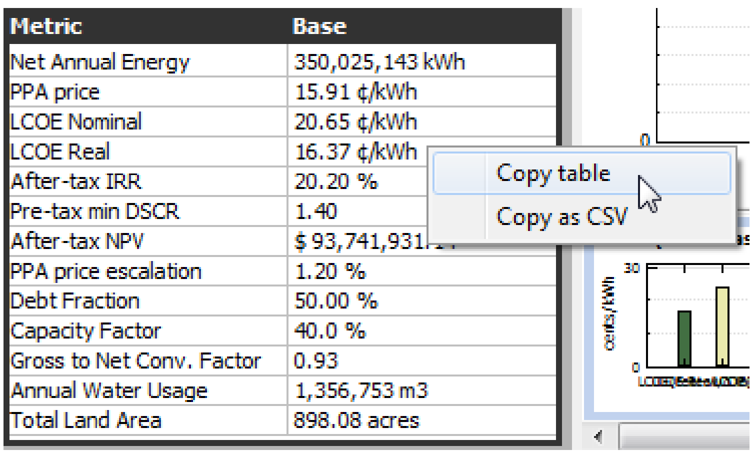
The Metrics table shows financial model results from the cash flow table and performance model results. For example, this Metrics table shows results for a residential PV system:

Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For certain simulation configurations, SAM displays two columns of values for each output variable:

- For model runs involving the Multiple Systems simulation configuration, SAM displays output variables for the active case in the Base column of the Metrics table, and output variables for the combined system in the Combined column.
- For model runs involving the Statistical simulation configuration, the values of mu, sigma are displayed in the second column of the Metrics table.

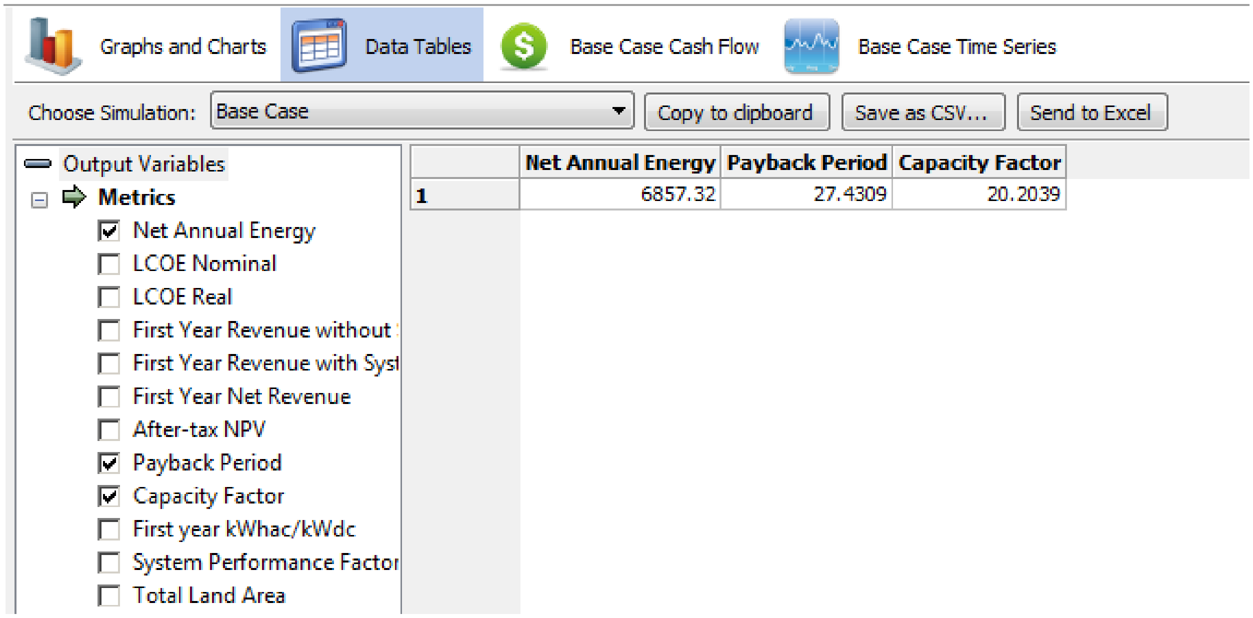
You can export data from the Metrics table by right-clicking it and choosing an option, **Copy table** to copy the data to your computer's clipboard, or **Copy as CSV** to export it to a comma-separated text file:



Metric	Base
Net Annual Energy	350,025,143 kWh
PPA price	15.91 ¢/kWh
LCOE Nominal	20.65 ¢/kWh
LCOE Real	16.37 ¢/kWh
After-tax IRR	20.20 %
Pre-tax min DSCR	1.40
After-tax NPV	$ 93,741,931
PPA price escalation	1.20 %
Debt Fraction	50.00 %
Capacity Factor	40.0 %
Gross to Net Conv. Factor	0.93
Annual Water Usage	1,356,753 m3
Total Land Area	898.08 acres

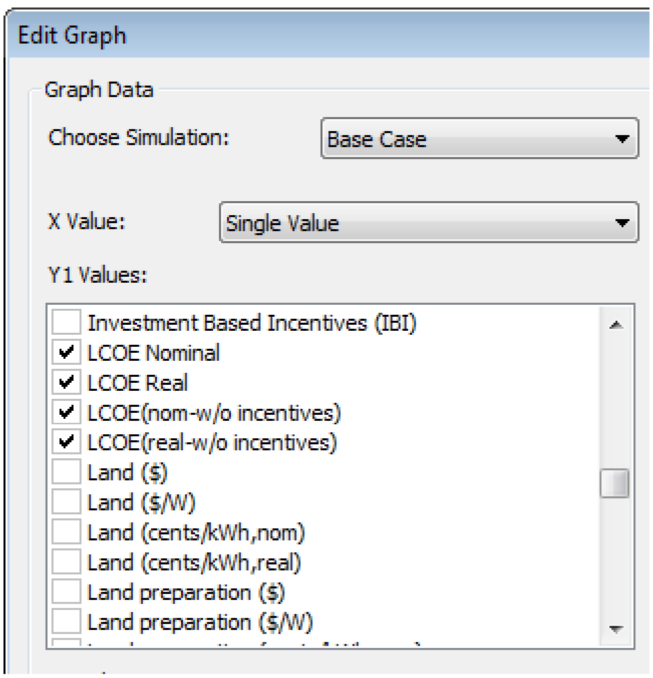
Metrics in Tables

You can also display the variables from the Metrics table in the Tables. This option allows you to choose a subset of the metrics variables, and to export the values. For example, this data table shows some of the metrics from the Metrics table above:



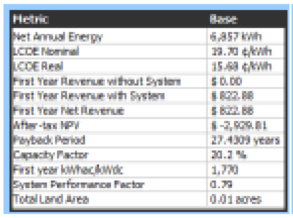
Metrics in Graphs

To display Metrics in Graphs, in the Edit Graph window, choose **Single Value** for the **X Value** option:



16.2 Graphs

SAM displays graphs on the Results page after running simulations. The standard graphs that appear by default show summaries of results from both the performance model and financial model. You can edit the standard graphs and create your own graphs.



Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

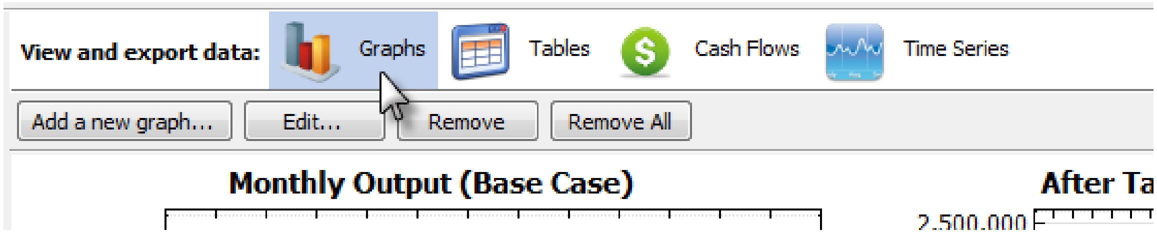
For descriptions of variables that appear in Graphs, see:

- Metrics Table Variables
- Cash Flow Variables
- Performance Model Results

Note. Values like *sv.npv* or *[not found]* indicate that there are no results to display. Try running simulations to display the values.

To show and hide graphs:

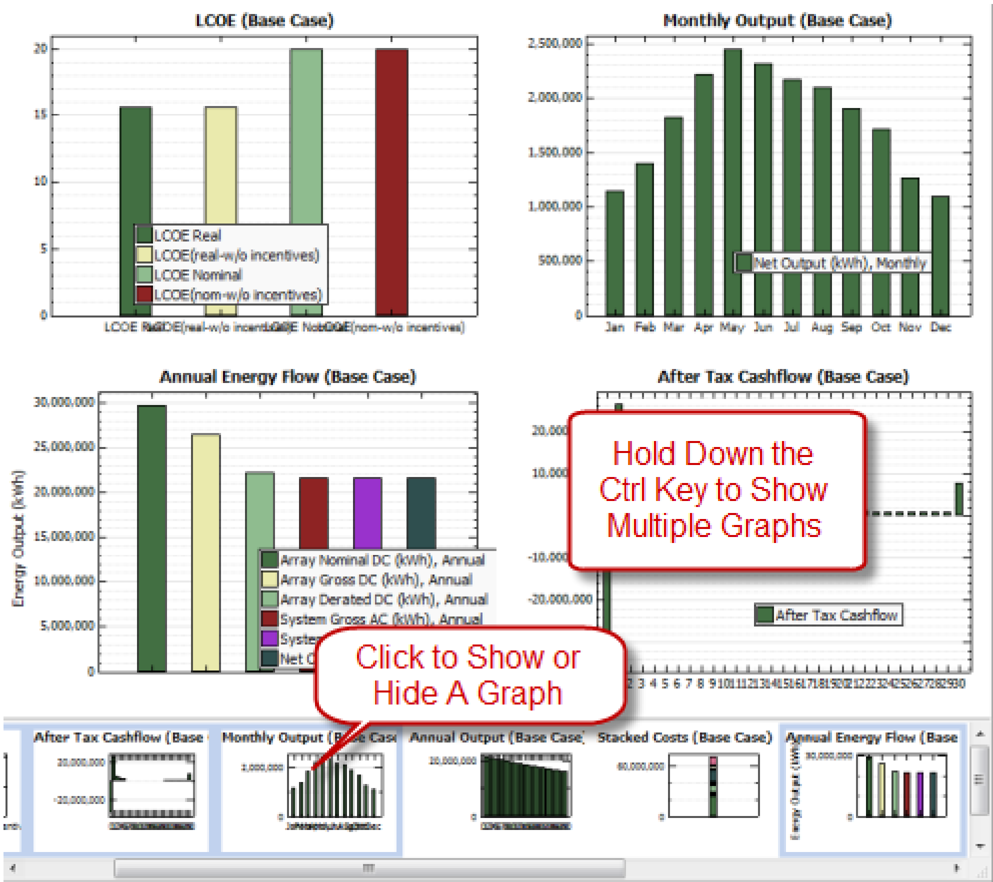
1. Click **Graphs** at the top of the Results page.



SAM displays a thumbnail of all of the graphs defined for the case. Some graphs are default graphs, and others are graphs that you may have added or edited.

2. Click a thumbnail at the bottom of the page to display a graph. Hold down the Ctrl key and click up to four graphs to display multiple graphs on the page.

To hide a graph, hold down the Ctrl key and click its thumbnail on the Graphing tab.



Manage Graphs

To create or modify graphs:

1. To add a graph to the list of available graphs, click **Add a new graph**.

   To modify an existing graph, select the graph name in the available graphs and click **Edit**. You can also modify a visible graph by right-clicking it.
2. In the Edit Graph window, choose data to graph and other graph properties.

   Use the Properties options to assign graph labels, adjust line thickness, show and hide the legend, and change other properties.

To remove graphs:

1. Click the thumbnail for up to four graphs that you want to remove.
2. Click **Remove**.

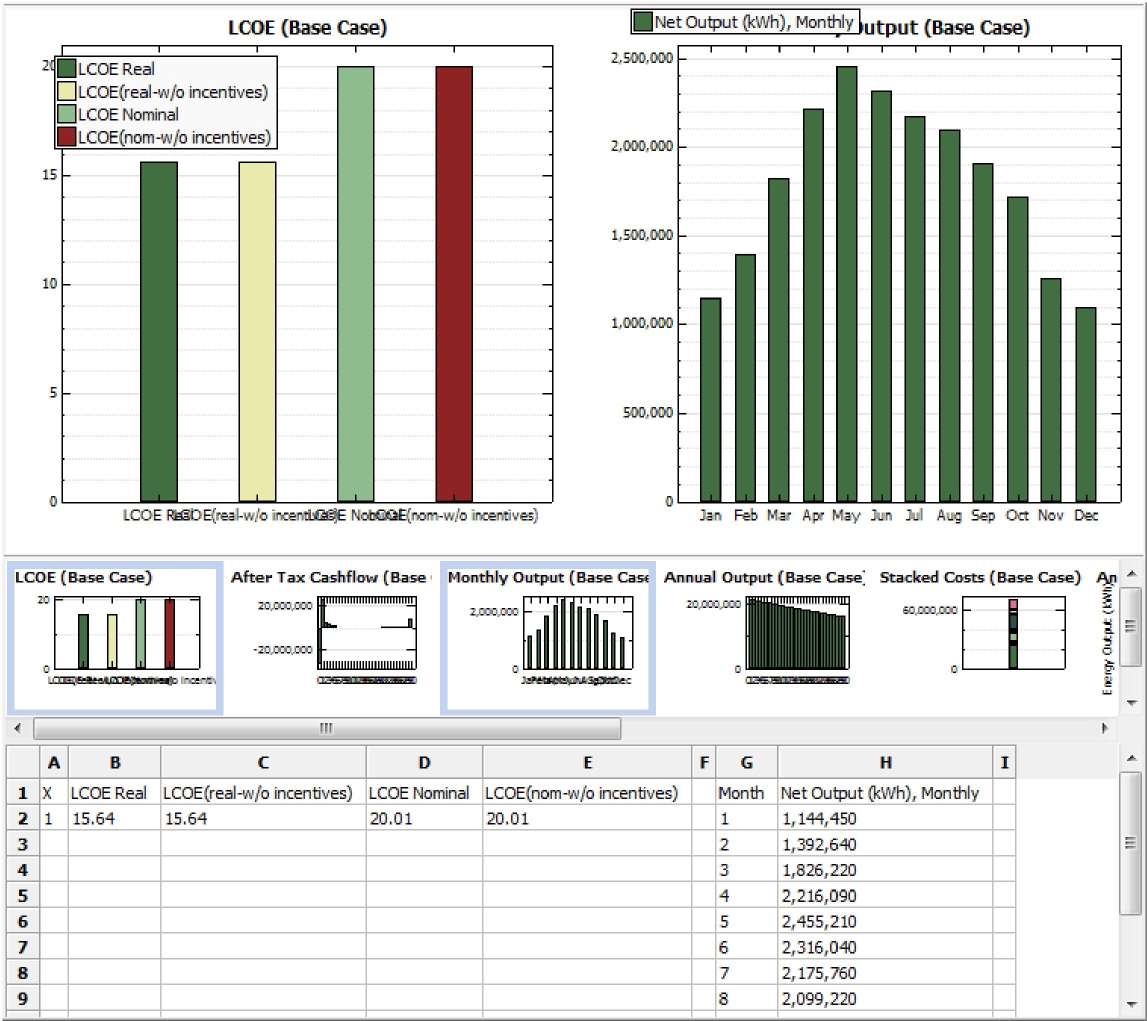
   To remove all graphs, including default graphs, click **Remove All**.

View Graph Data

You can view tables of data for graphs visible on the Results page and export the data to text files.

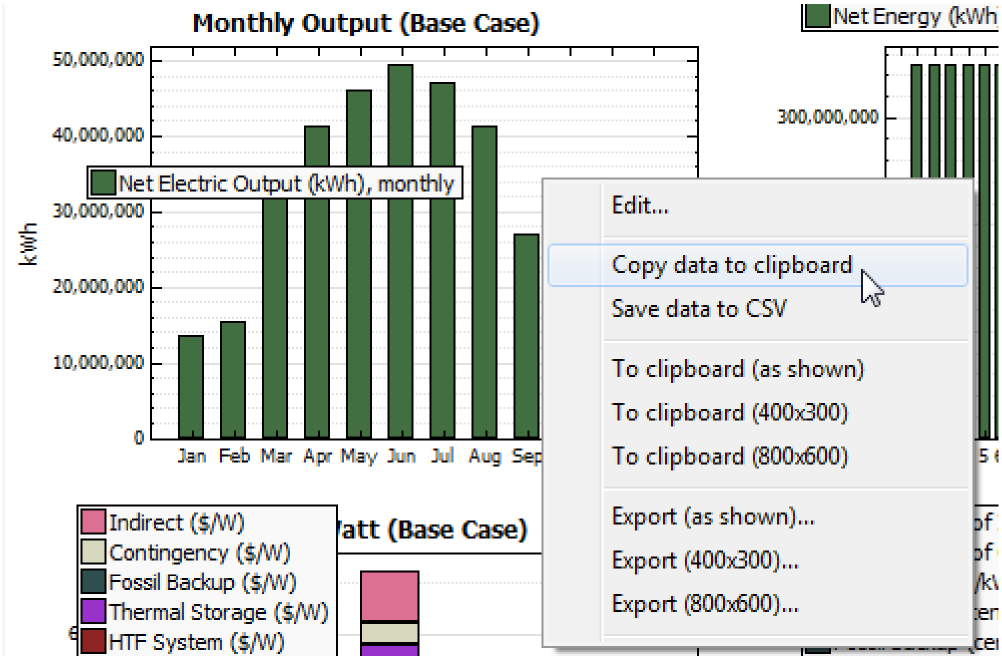
To view graph data:

1. On the Results page, click **Graphs**.
2. Click the thumbnails at the bottom of the page to show up to four graphs. (Hold down the ctrl key while clicking the thumbnails to show more than one graph.)
3. Click **Show Graph Data**.



To export graph data:

- To export data from a graph, right-click the graph and choose an export option:

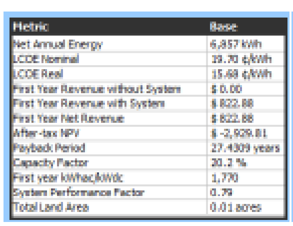


Tips for working with graphs

- Right-click a graph to hide the legend, change line thickness and colors, edit graph legends, and modify other graph properties.
- Click the Notes button above the top right corner of the Results page to display an editable text box to make notes about a graph.

16.3 Tables

The Tables on the Results page display results from the performance and financial models from the base case simulation, which reflects data specified on the input pages, and from parametric analyses and other advanced analyses involving multiple simulations.



Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

Note. Values like *sv.npv* or *[not found]* indicate that there are no results to display. Try running simulations to display the values.

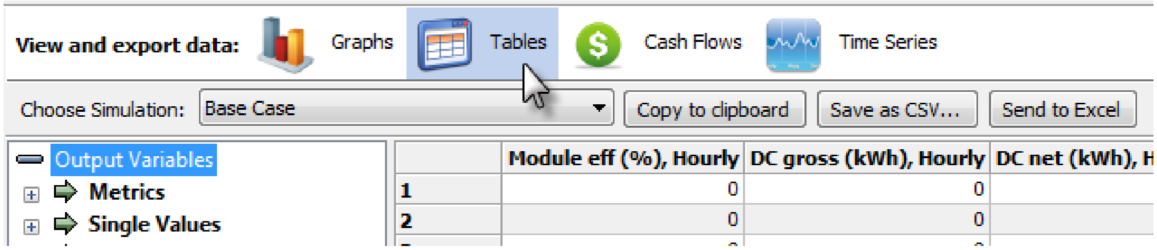
For descriptions of the variables shown in Tables, see:

- Time series (hourly) and monthly performance data: Performance model results.
- Annual cash flow data: Cash flow variables

- Time-dependent pricing data: Time Dependent Pricing Overview

To view the Tables:

1. On the Results page, click **Tables**.

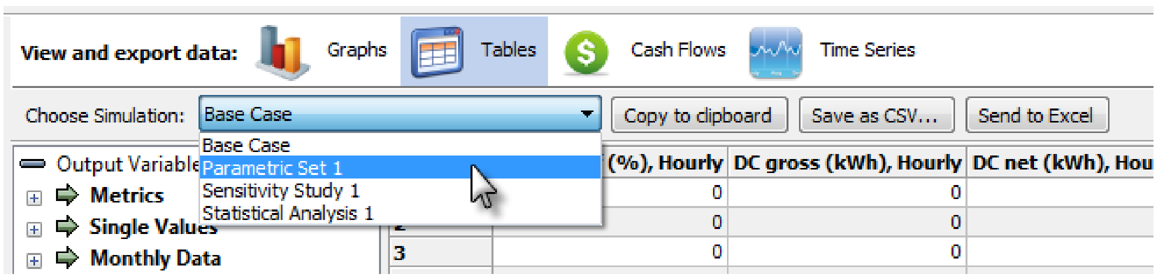


   If you do not see the Hourly Data list, run simulations to generate the list.

2. In the **Choose Simulation** list, select the simulation results you want to display:

   To display results based on input variable values from the input pages, choose **Base Case**. (This may be the only option available.)

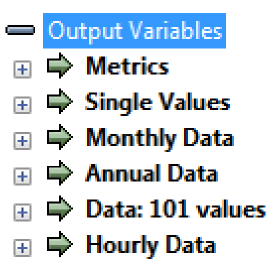
   If your analysis involves multiple simulations, such as for parametric analyses, choose the appropriate option. For example, **Parametric Set 1**.



3. In the navigation tree under **Output Variables**, check the box for each variable you want to display in the table.

Tables Categories

The Tables categories are based on the number of values that a variable represents.



For example:

- The *LCOE Nominal* variable is in the Metrics table, so it appears in the **Metrics** list.
- *LCOE(real-w/o incentives)* has one value and does not appear in the Metrics table, so it appears in the **Single Values** list.
- *Annual Water Usage* (for some CSP systems) has one value, so it appears in the **Single Values** list.
- *After Tax Cash Flow* contains a value for each year of the analysis period, so it appears in the **Annual**

Data list.

- *Monthly Energy* contains values for each month of the year (12 values), so it appears in the **Monthly Data** list.
- *Hourly Energy* contains 8,760 values, or one for each hour of the year, so it is in the **Hourly Data** list.

Note. In some cases, the data table includes categories with the number of values in the name, for example **Data: 101 values** lists variables with 101 values for testing the financial model results.

Metrics

Results from the Metrics table.

Single Values

Results that have a single value, including:

- Some input variable values from the System Costs, Financing, and Incentive pages.
- Annual totals or averages of hourly performance model results, or time-dependent pricing data.

Monthly Data

Results that have of twelve values, including monthly averages and totals of hourly values

Annual Data

Results that have a value for each year in the analysis period, including:

- Cash flow data
- Annual output data

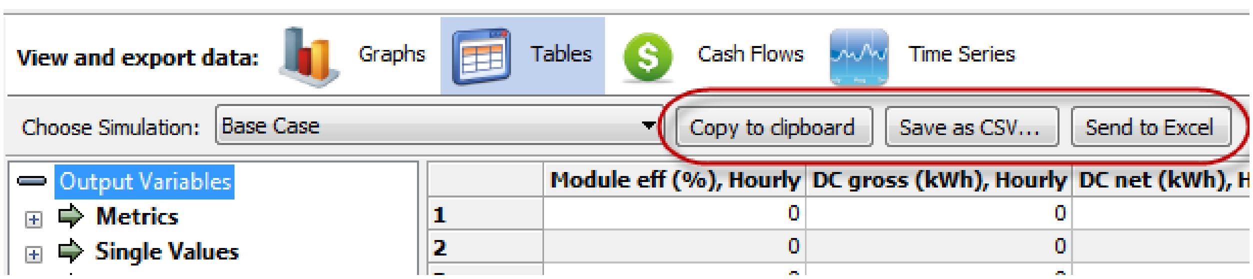
Note. Row 1 in the annual data table is equivalent to Year zero in the project cash flow.

Hourly Data

Results with 8,760 hourly values from the performance model results.

Note. If you do not see the **Hourly Data** list, run simulations to generate the list. SAM deletes stored hourly data when you close the file to save storage space.

Exporting Data from Tables



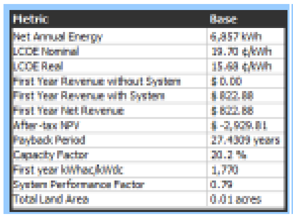
SAM offers three options for exporting the cash flow table:

- **Copy to clipboard** copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.
- **Save as CSV** saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.

- **Send to Excel (Windows only)** saves the table in an Excel file.

16.4 Cash Flows

The Cash Flows table displays the project cash flow calculated by the financial model. The Cash Flows table only displays data from the base case, which is the set of results calculated from the input variable values that are visible on the input pages.



Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

For descriptions of variables that appear in the Cash Flows table, see Cash flow variables.

Notes.

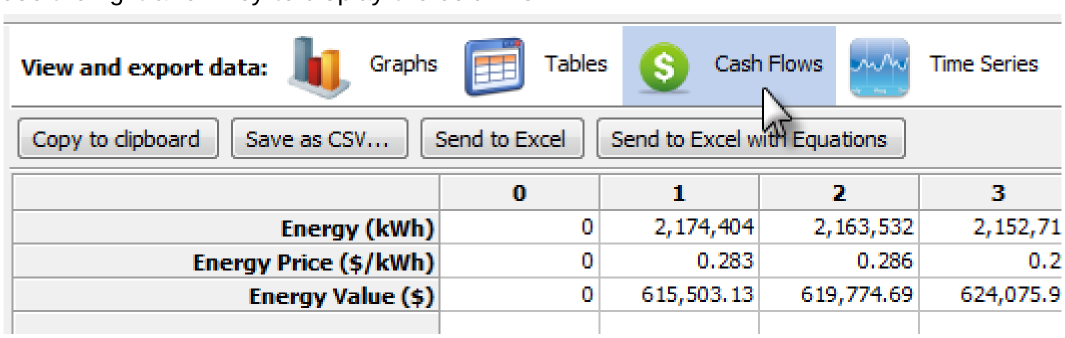
To see cash flow data for analyses involving multiple runs such as parametric analyses, use Tables to display the cash flow variables.

Values like *sv.npv* or *[not found]* indicate that there are no results to display. Try running simulations to display the values.

To view the Cash Flows table:

- On the Results page, click **Cash Flows** at the top of the page.

  If you have trouble seeing values in columns at the far right of the table, click a cell in the table and use the right-arrow key to display the columns.



SAM offers three options for exporting the cash flow table:

- **Copy to clipboard** copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.
- **Save as CSV** saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.
- **Send to Excel (Windows only)** creates a new Excel file that contains the data from the cash flow table in an Excel file, but no formulas.

- **Send to Excel with Equations (Windows only)** exports the cash flow data to an existing Excel workbook that contains formulas to illustrate how SAM's internal cash flow calculations work. The workbooks are in the *\exelib\spreadsheets\equations* folder of your SAM installation folder.

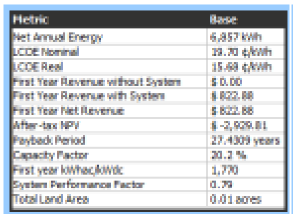
Notes.

SAM makes cash flow calculations internally during simulations. It does not use Excel to make the calculations. The two **Send to Excel** options are to help you analyze the cash flow data and understand how SAM's internal calculations work.

You can also display cash flow data by building a Table. This option allows you to choose the rows to include in the table, and also makes it possible to show cash flow results from a parametric analysis.

16.5 Time Series

The Time Series viewer on the Results page displays time series data from the performance model, and time-dependent pricing data from the financial model.



Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

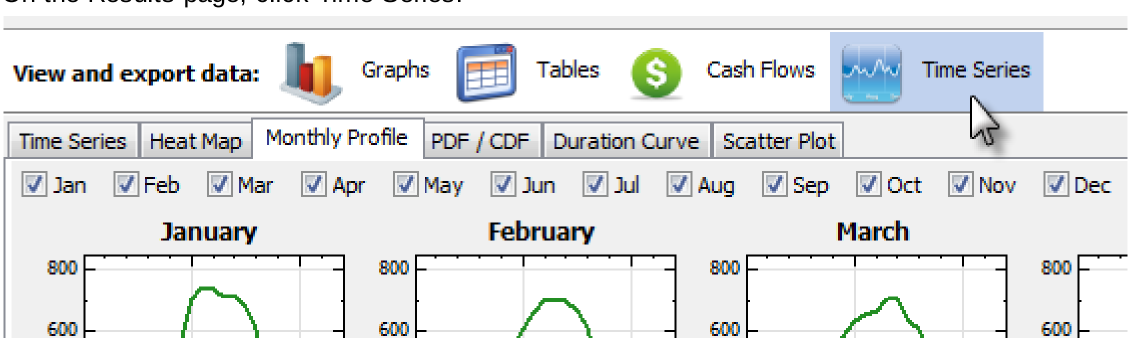
For a description of the variables, see:

- Performance Model Results
- Savings and Revenue

Note. Values like *sv.npv* or *[not found]* indicate that there are no results to display. Try running simulations to display the values.

To view the Time Series graphs:

1. On the Results page, click Time Series.



2. Click a tab to display time series data in one of the types of graphs described below.

3. Choose variables to display in the graph by checking boxes or choosing from lists as appropriate.

Tips for using the Time Series Graphs:

- To zoom in or out, use the mouse wheel. Zooming centers on the mouse location. Not all graphs can be zoomed.
- You can also zoom by highlighting a region with your mouse.
- On some tabs, you can view several variables at once on the same graph.
- Scroll the graph with your mouse wheel by holding shift while scrolling.
- The axes on the Time Series tab and Heat Map tab can be synchronized by checking the synchronize axes box in the top left corner.

Graph Controls:

- Drag the mouse – zoom in
- Ctrl + Drag – zoom in x direction only by dragging (where applicable)
- Shift + Drag – Pan plot
- Mouse Wheel – zoom plot
- Shift + Mouse Wheel – Scroll plot horizontally
- Ctrl + Mouse Wheel – Scroll plot vertically (where applicable)

Time Series Graph Types

Time Series

The time series tab shows a line graph of the selected variables over time. The graph is can be scrolled and zoomed. Variables that are selected in the left column of check boxes appear in the top graph, and variables selected in the right column appear in the bottom graph. Line colors are automatically assigned when a variable is selected. You can zoom and scroll the graph with the controls on the bottom, or with the mouse. You can also zoom by highlighting the region you want to view. In the top left corner, you can choose to interpolate points linearly or with a step function, or you can turn interpolation off.

Heat Map

The heat map allows you to see how the data varies by time of day and by time of year on the same graph. The time of year is on the x axis, and the time of day is on the y axis. Only one variable at a time can be viewed on the heat map. Choose the variable you would like to view from the drop-down list at the top. Like the time series plot, the heat map can be scrolled and zoomed. Note that the heat map can zoom in both the x and y directions. You can zoom in both directions at once by highlighting a rectangular region with your mouse. Alternatively, you can use the ctrl key to zoom in the x direction only. The default color map is Coarse Rainbow. The Fine Rainbow color map provides higher color resolution, and the Hot Cold color map ensures that values above zero are red, and values below zero are blue. You can select the color map you want to use in the top right corner. Next to the color map drop-down, you can set the maximum and minimum bounds for the color map.

Monthly Profile

The monthly profile tab shows the average daily profile in each month of the year. Select the variable you would like to view along the right hand side. You can view multiple variables at the same time, and they will be plotted on the same surface. Again, line colors are automatically assigned. Along the top, you can select which months you would like to view. You can also view an annual profile, which is calculated by averaging all of the monthly profiles.

PDF/CDF

The PDF/CDF tab shows the probability density function and cumulative distribution function for a single variable.

The probability density function is displayed as a histogram because it is calculated by dividing the data into a number of bins. Changing the number of bins may reveal different properties about the data. The default number of bins is determined by Sturge's formula. Sturge's formula says that for n data points, we use $log_2(n) + 1$ bins. The default behavior in Excel is to use the square root of the number of data points to determine the number of bins. This is provided as an option in the combo-box in the top right corner. You may also enter into the combo box any integer value you would like to use.

In addition to specifying the number of bins, you can also specify how the histogram should be scaled. Scaling the histogram differently will not change its shape, but it will change the units on the y-axis. The default is a scaled histogram, which means that bar heights are treated as percentages, and the sum of the bar heights must be 100%. If the histogram is scaled by bin width, it is scaled so that the total area of the bars is equal to one. This is the best approximation of the probability density function since the area under a PDF curve must be equal to one. You can also choose to not scale the histogram, in which case the y-axis displays the number of data points in each bin as a traditional histogram does. For any choice of scale, you can change the y maximum in the upper left hand corner to get a better view of the smaller bars.

The cumulative distribution function shows the percentage of data points at or below a certain value. The displayed cumulative distribution function is an empirical CDF. This means that it is a step function that increases at each data point, and is flat in-between. For a large number of data points, this is a very good approximation to the true CDF. The CDF will always start at 0 and increase to 100%.

Duration Curve

The duration curve shows the number of hours that are equaled or exceeded by the value on the y-axis. For example, the best-case hourly energy will have very few hours equaled or exceeded, as indicated by the left side of the duration curve. The right side of the curve indicated the lowest value of the variable on the y-axis.

Scatter Plot

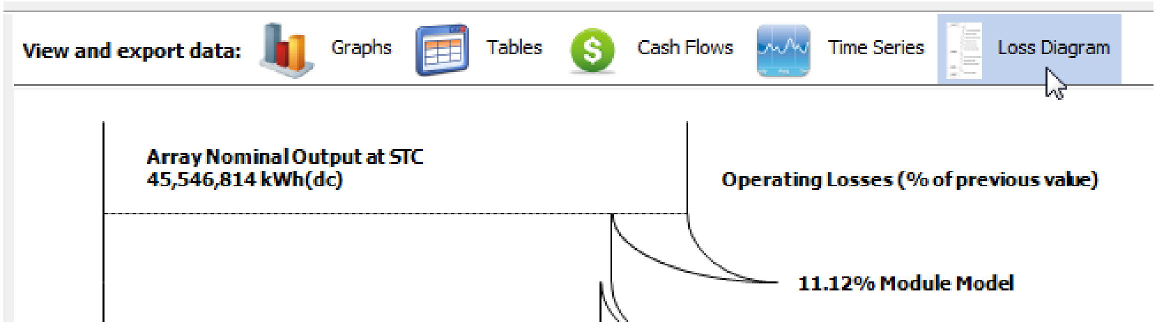
The scatter plot provides a way to view correlation between variables. First, choose the independent variable which will be displayed on the x-axis. Then, choose one or more dependent variables to be displayed on the y-axis. Clustering of the data points may indicate an underlying relationship between the variables. If the data points appear to be scattered randomly, there is little to no correlation.

16.6 Loss Diagram

SAM displays a Sankey diagram showing the energy at different points in the system, and the source of energy losses at each point.

To view the loss diagram:

- On the Results page, click **Loss Diagram**.



In some cases the energy value at a point in the system may be greater than at the previous point. For example, a CSP system with fossil backup may be configured so that the energy delivered to the power block is greater than the energy from the solar field. In that case, SAM displays the negative value in parentheses.

Note. SAM does not display an energy loss diagram for all of the performance models. If you do not see the Loss Diagram button on the Results page, the diagram is not available.

Using the Loss Diagram in your Documents

SAM includes a copy of the energy loss diagram in reports.

You can also copy the diagram to your clipboard to use in documents using your operating system's clipping tool:

- In Windows 7, use the Snipping Tool (type "Snip" in the Windows search box). In Windows 7 and older versions of Windows, you can use the Print Screen key to copy an image of your screen to the clipboard.
- In OS X, press the Command-Shift-4 keys to drag an area on your screen and save it to an image file.

17 Reports

A report is a PDF document with text, tables, and graphs describing your analysis. A report draws data from inputs and results.

- Generate Reports explains how to create a report using a pre-defined report template.

17.1 Generate Reports

SAM's report generator creates a PDF file that may include the following:

- Values of input and results variables.
- Values calculated for the report using the report generator's equations.
- Graphs of results data.
- Tables of input or results data.
- Text and images.

The report generator uses a report template to generate a report using data from the case that you specify. SAM comes with a set of report templates for some combinations of performance and financial models.

> **Note.** The report template editor is not supported in the current version of SAM. If you have requests for items that you would like to appear in reports, please post your request on the SAM Support forum at https://sam.nrel.gov/forums/support-forum.

To generate a report:

1. Open the .zsam file containing the case or cases from which you want to generate the report.
2. Click a case in the file. SAM generates reports for the current case.
3. On the Tools menu, click **Reports**, **Create report from current case**, or press Ctrl-R.
4. In the Report Generation window, choose the name of the report template on which you want to base the report.
5. In the Export PDF Report window, type a file name and choose a folder.

18 Financial Metrics

SAM displays financial metrics on the Results page after running simulations.

For a general description of the Metrics table, see Metrics Table.

For a list of financial metrics with links to descriptions, see Financial Metrics Overview.

The financial metrics are:

- Project Costs
- Debt and Equity
- Debt Fraction
- Financing Cost
- Electricity Cost and Savings
- Internal Rate of Return (IRR)
- Land Area
- Levelized Cost of Energy (LCOE)

- Minimum DSCR
- Net Present Value (NPV)
- Payback Period
- PPA Price
- PPA Price Escalation
- Real Estate Value Added

18.1 Financial Metrics Overview

The financial metrics are selected single-value results from the financial models and performance models.

After running simulations, SAM displays the financial metrics on the Results page:

- Metrics table
- Tables, under **Metrics** (with additional variables under **Single Value**)
- Graphs, with the **Single Value** option for **X Value**, or with parametric or other analysis options that involve input variables with multiple values.

Financial Metrics

SAM displays different metrics depending on the financing option that you specify on the Technology and Market window. For example, SAM displays the payback period for the residential and commercial financing option, but not for the utility options.

Note. SAM displays financial metrics even when they indicate a financially non-feasible project because the software cannot tell when such results indicate an infeasible project, or when they indicate a mistake in the inputs.

When you see metrics that do not make sense, check your assumptions to make sure you did not make a mistake. Some examples of financial metrics that may indicate a problem with your assumptions are:

A very high NPV with negative LCOE values for residential or commercial financing may indicate that Year Zero incentives are greater than the project total installed cost: Check that you correctly specified the incentives on the Incentives page.

A negative IRR with negative NPV for commercial PPA or utility financing may indicate that project cash flows are insufficient to cover the Year Zero investment cost: Check that the costs on the System Costs page are not too high.

An IRR of zero with positive NPV and debt fraction greater than 100% for one of the advanced utility financing options may indicate that the debt funding amount is greater than the project total installed cost: Check that the debt interest rate on the Financing page is not too low.

The following table shows the financial metrics and options. The table uses the following abbreviations for the financing options:

- Res: Residential
- Com: Commercial
- Com PPA: Commercial PPA
- IPP: Utility Independent Power Producer
- LPF: Utility Leveraged Partnership Flip
- AEPF: Utility All Equity Partnership Flip
- SL: Utility Sale Leaseback
- SO: Utility Single Owner

Table 17. Financial model results in the Metrics table for different financing types.

Metric	Res	Com	Com PPA	IPP	LPF	AEPF	SL	SO
Net Annual Energy (Annual Energy Saved)	•	•	•	•	•	•	•	•
PPA price			•	•	•	•	•	•
LCOE Nominal	•	•	•	•				
LCOE Real	•	•	•	•				
Electricity cost without system	•	•						
Electricity cost with system	•	•						
Net savings with system	•	•						
After-tax IRR			•	•				
Pre-tax min DSCR			•	•				
After-tax NPV	•	•	•	•				
Payback Period	•	•						
PPA price escalation			•	•	•	•	•	•
Debt Fraction			•	•				
IRR target year					•	•	•	•
IRR target					•	•	•	•
IRR actual year					•	•	•	•
IRR in target year					•	•	•	•
After-tax tax investor IRR					•	•	•	
After-tax tax investor NPV					•	•	•	
After-tax developer IRR					•	•	•	
After-tax developer NPV					•	•	•	
Direct Cost					•	•	•	•
Indirect Cost					•	•	•	•
Financing Cost					•	•	•	•
Total project cost					•	•	•	•
Total debt					•			•
Total equity					•	•	•	•
Real Estate Value Added	•	•						

18.2 Project Costs

For the advanced utility IPP financing options, SAM displays some key cost metrics on the Results page for convenience in assessing the financial viability of a project:

- Single owner
- Leveraged Partnership Flip
- All Equity Partnership Flip
- Sale Leaseback

The direct and indirect costs are inputs that you specify on the System Costs page.

Direct Cost

The sum of the direct installation costs from the System Costs page.

Indirect Cost

The sum of indirect installation costs from the System Costs page.

Total project cost

The total project cost is the sum of direct, indirect and financing costs:

Total Project Cost ($) = Direct Cost ($) + Indirect Cost ($) + Financing Cost ($)

18.3 Debt and Equity

For the advanced utility IPP financing options that include debt (single owner and leveraged partnership flip), SAM displays the total debt and equity amounts on the Results page.

Note. For the residential, commercial, commercial PPA, and utility IPP financing options, you specify the debt fraction as an input on the Financing page. For the advanced utility financing options that include project debt, SAM calculates the debt and equity amounts based on the assumptions you specify on the Financing and System Costs pages.

Total Debt

The debt funding amount from the project cash flow. For a description of how SAM calculates the debt funding amount for the different financing options, see:

- Single Owner
- Leveraged Partnership Flip

Total Equity

The project equity investment. For the single owner and leveraged partnership flip financing options that include debt, the total equity is the project cost less total debt:

Total Equity ($) = Project Cost ($) - Total Debt ($)

For the all equity partnership flip and sale leaseback options that do not include project debt, total equity is equal to the project cost:

Total Equity ($) = Project Cost ($)

18.4 Debt Fraction

The debt fraction is the project debt amount as percentage of the total project cost. For example, a debt fraction of 25% means that the project borrows 25% of the total installed cost for a debt-equity ratio of 25%.

The debt fraction is an input on the Financing page for the following financing options:

- Residential
- Commercial
- Commercial PPA and Utility IPP*

*For these options, if you check **Allow SAM to pick a debt fraction to minimize the LCOE** on the financing page, then SAM calculates the debt fraction as a result.

For the following advanced utility financing options that involve project debt, SAM calculates the project costs and debt and equity amounts to satisfy the assumptions you specify on the System Costs page and Financing page:

- Single Owner
- Leveraged Partnership Flip

For the single owner and leveraged partnership flip options, the debt fraction is:

Debt Fraction (%) = Total Debt ($) ÷ Total Project Cost ($) × 100%

The following financing options do not involve a debt fraction:

- All Equity Partnership Flip
- Sale Leaseback

18.5 Financing Cost

The financing cost is reported on the Results page for the advanced utility financing options. The financing cost is the sum of the various financing costs that you specify on the Financing page:

- Single Owner
- Leveraged Partnership Flip
- All Equity Partnership Flip
- Sale Leaseback

Single Owner

Financing Cost = Debt Closing Costs + Debt Service Reserve + Construction Financing + Working Capital Reserve + Other Financing Cost

Leveraged Partnership Flip

Financing Cost = Development Fee + Debt Closing Costs + Equity Closing Costs + Debt Service Reserve + Construction Financing + Working Capital Reserve + Other Financing Cost

All Equity Partnership Flip

Financing Cost = Development Fee + Equity Closing Cost + Construction Financing + Working

Capital Reserve + Other Financing Cost

Sale Leaseback

Financing Cost = Development Fee + Equity Closing Cost + Lease Payment Reserve + Construction Financing + Working Capital Reserve + Other Financing Cost

Where the following costs are reported on the Cash Flow table:

- *Debt Service Reserve*
- *Working Capital Reserve*

And the following costs are either inputs, or shown as calculated values on the Financing page:

- *Construction Financing*
- *Other Financing Cost* (shown as Financing Cost on the Financing page)
- *Equity Closing Cost*

And the remaining costs are calculated as follows using values from the Financing page:

Debt Closing Costs = Debt Closing Costs + Debt Closing Fee (%) × Debt Funding

Where *Debt Funding* is shown on the Cash Flow table.

Lease Payment Reserve = Lessor Required Lease Payment Reserve (months) / 12 (months/yr) × Year 1 Pre-tax Operating Cash Flow ($/yr)

18.6 Electricity Cost and Savings

For the residential and commercial financing options, SAM assumes that electricity generated by the system displaces purchases of electricity from the grid to meet a building or facility electric load. You specify the electricity rates on the Utility Rate page, and the load on the Electric Load page.

SAM calculates the first year cost of purchasing electricity from an electricity service provider for two scenarios, one with and one without the renewable energy system, and then calculates the net savings as the difference between the two. SAM assumes the same electric load and electricity rate structure for both scenarios.

Notes.

The cost and savings values in the Metrics table are for Year 1 of the project cash flow. For a description of how to display annual, monthly, and hourly values, see Retail Electricity Savings.

For an example of how to compare the with system scenario to a without system scenario that uses a different rate structure, see the sample file *SamUL Cost Savings with Different Rate Structures* (click **File**, **Open sample file**.

Electricity cost without system, $/year

The cost of electricity that would be purchased to meet the building or facility electric load with no renewable energy system.

Electricity cost with with system, $/year

The cost of electricity purchased from the grid, assuming that the project sells electricity generated by the system in excess of the load.

Net savings with system, $/year

The difference between costs without system and with system:

Net Savings = Cost without System - Cost with System

Note. Net savings with system is equal to Energy Value for Year one of the project cash flow.

18.7 Internal Rate of Return (IRR)

The internal rate of return is the *nominal* discount rate that corresponds to a net present value of zero for projects with commercial PPA or utility financing as defined in the Technology and Market window.

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+IRR)^n} = 0$$

Where *After Tax Cash Flow* is in the project cash flow table.

Depending on the financing option, the after-tax cash flow is either from the project perspective,

- Commercial PPA
- Utility IPP
- Single Owner

from the perspective of each of the partners,

- All Equity Partnership Flip
- Leveraged Partnership Flip

or parties,

- Sale Leaseback

Note. If you try to replicate the IRR equation in Excel or other spreadsheet software by exporting the cash flow table and using the NPV formula on the appropriate after-tax cash flow row, you may find that the IRR value that SAM calculates does not appear to result in an NPV of zero. (It will always be close to zero compared to the magnitude of the cash flows.) This is because SAM reports the IRR to four significant digits, and for projects with large cash flows, a higher accuracy may be required to show the value that results in an NPV closer zero. For example, for a $74 million project with average annual after-tax cash flows of $3.9 million, SAM reports an IRR of 22.56% in the Metrics table, and 22.5589 in Tables. In Excel, the formula =NPV(0.2256,B60:AF60) results in an NPV of -$573.96 dollars, while the formula =(0.225589632,B60:AF60) results in an NPV value of -$0.02. For this example, it would be reasonable to consider the IRR to be 22% or 23%.

Solution Mode and IRR Target Values

For all of the financing options, you choose a solution mode on the Financing page that determines whether SAM calculates the IRR to meet a desired PPA price that you specify, or calculates a PPA price based on the IRR that you specify.

For a description of the solution mode inputs on the Financing page for each option, see:

- Commercial PPA
- Utility IPP
- Single Owner
- All Equity Partnership Flip
- Leveraged Partnership Flip
- Sale Leaseback

SAM calculates an IRR value for each year in the analysis period, and determines the year that the target IRR occurs.

SAM displays the IRR target and IRR target year (if it applies) on the Results page for reference:

IRR target year

IRR target year is equal to the value that you specify on the Financing page.

- In Specify Target IRR mode, SAM adjusts the PPA price so that the target IRR occurs as close as possible to the target year, and reports the year that the target IRR occurs as the IRR actual year.
- In Specify PPA Price mode, SAM displays the IRR in target year for reference. (Changing the IRR target year on the financing year changes the IRR in target year without affecting the cash flow and other results.)

IRR target

The target IRR that you specify on the Financing page.

Commercial PPA and Utility IPP

For the commercial PPA and utility IPP financing options, the IRR is for the project over the full analysis period. You either specify the IRR or an IRR target on the Financing page:

After-tax IRR

The project IRR, equivalent to the nominal discount rate that the project after-tax NPV equals zero.

Single Owner

For the single owner financing option, the IRR is for the project, as close as possible to the target year that you specify on the Financing page:

IRR in target year

The project IRR in the "IRR actual year."

Partnership and Sale Leaseback

For the leveraged partnership flip, all equity partnership flip, and sale leaseback financing options that involve two project partners, SAM reports the IRR from the perspective of each partner, and the year in which the investor's IRR is met:

IRR actual year

The year in which the tax investor achieves its IRR.

After-tax tax investor IRR

The IRR from the tax investor's perspective.

After-tax developer IRR

The IRR from the developer's perspective.

18.8 Land Area

For some of the performance models, SAM reports an estimate of the land area required for the project. SAM uses the value to calculate any land-related costs that you specify in $/acre on the System Costs page.

Solar Power Systems

In general, for solar projects, the land area is the product of a packing factor that you specify, and the area of the solar array or field.

For the solar models that calculate a land area value, SAM copies the value from the following input pages (follow the links to see descriptions of how SAM calculates the value):

- Flat Plate PV: Array page
- Parabolic Trough: Solar Field page. SAM uses the same equation for the physical and empirical models.
- Power Tower: Heliostat Field page. SAM uses the same equation for molten salt and direct steam.

Wind Power Systems

Note. SAM calculates a land area for wind projects, but does not use the value in cost calculations.

For the wind power model, SAM reports the land area as "Approximate land use" in square meters. SAM calculates the value based on the number of turbines and spacing inputs that you specify on the Wind Farm page.

$$\begin{aligned} \textit{Approximate Land Use} = {} & \textit{Turbines in Layout} \times 100\ m^2 \\ & + \textit{Turbines in Layout} \times 4\ m \times \textit{Turbine Spacing}\ (m) \\ & + 5{,}000\ m^2 \\ & + 100\ m^2 \times \textit{Turbines in Layout} \end{aligned}$$

The assumptions for the wind land use value are:

- Each turbine requires a 10 m by 10 m foundation.
- There is a 4 m wide road between each turbine.
- The wind farm requires 5,000 m² of land for facilities such as buildings and staging areas, regardless of the wind farm size.
- Each turbine requires an additional 100 m² of land. (This ensures that larger wind farms have more land for facilities.)

18.9 Levelized Cost of Energy (LCOE)

Contents

The LCOE is the total cost of installing and operating a project expressed in dollars per kilowatt-hour of electricity generated by the system over its life. It accounts for:

- Installation costs
- Financing costs
- Taxes
- Operation and maintenance costs
- Salvage value
- Incentives
- Revenue requirements (for utility financing options only)
- Quantity of electricity the system generates over its life

The LCOE in SAM depends on the following assumptions:

- The quantity of electricity generated by the system for each year in the analysis period, shown as Energy in the cash flow table. The performance model calculates the annual energy for Year one based on the hourly simulations. SAM adjusts this value by the factors that you specify on the Performance Adjustment page.
- Installation and operating costs on the System Costs page
- Financial assumptions on the Financing page
- Incentives on the Incentives page
- Depreciation assumptions on the Depreciation page

To use the LCOE for evaluating project options, it must be comparable to cost per energy values for alternative options:

- For residential or commercial projects, SAM assumes that the renewable energy system meets all or part of a building's electric load, so the LCOE is comparable to a $/kWh retail electricity rate representing cost of the alternative option to meet all the building's load by purchasing electricity from the grid at retail rates. To be economically viable, the project's LCOE must be equal to or less than the average retail electric rate.

- For utility (and commercial PPA) projects, SAM assumes that the project sells all of the electricity generated by the system at a price negotiated through a power purchase agreement (PPA). For these projects the LCOE is comparable to the power price. A financially viable project must have an LCOE that is equal to or greater than the available PPA price to cover project costs and meet internal rate of return requirements.

Real and Nominal LCOE

For all financing options, SAM calculates both a real and nominal LCOE value. The real LCOE is a constant dollar, inflation-adjusted value. The nominal LCOE is a current dollar value.

The choice of real or nominal LCOE depends on the analysis. Real (constant) dollars may be appropriate for long-term analyses to account for many years of inflation over the project life, while nominal (current) dollars may be more appropriate for short-term analyses.

Some industries prefer to use one form over the other. For example, when discussing LCOE for parabolic trough projects, analysts have tended to use the nominal LCOE (see Current and Future Costs for Parabolic Trough and Power Tower Systems in the US Market), while the U.S. Department of Energy has used the real LCOE in its comparative analysis of photovoltaic project costs (Solar Energy Technologies Program Multi-Year Program Plan 2007-2011).

Be sure to use the same form of the LCOE when comparing costs for different alternatives: Never compare a real LCOE of one alternative with a nominal LCOE of another.

LCOE Without Incentives

SAM displays a value labeled "LCOE (real-w/o incentives)" on some graphs. This value of the LCOE is calculated in the same way as the other forms of the LCOE described below, but excludes any tax credits or cash incentives that you specify on the Incentives page.

If you remove all incentives from your analysis, then the LCOE values with and without incentives are identical.

Additional Resources

You can explore the LCOE methodology for the residential, commercial, commercial PPA, and utility IPP financing options by downloading the spreadsheets from the SAM website at https://sam.nrel.gov/financial, or from SAM's Help menu. Each of the five spreadsheets duplicates SAM's cash flow equations using Excel formulas.

For more information about the levelized cost of energy and other economic metrics for renewable energy projects, see *Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies*. (Short 1995) http://www.nrel.gov/docs/legosti/old/5173.pdf.

LCOE Definition

This description of the LCOE uses the vocabulary and equations described in the *Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies*. (Short 1995) http://www.nrel.gov/docs/legosti/old/5173.pdf.

By definition, a project's equivalent annual cost C_n is the product of the LCOE and the quantity of electricity generated by the system in that year, Q_n:

$$C_n = Q_n \times LCOE$$

Project costs C_n include installation, operation and maintenance, financial costs and fees, and taxes, and also account for incentives and salvage value. SAM's performance model calculates the annual energy Q_n for n = 1. For n > 1, Q_n decreases from year to year if the **Year-to-year decline in output** value on the Performance Adjustment page is greater than zero.

That equation must be valid for all years in the project's life, so to calculate the LCOE, we must first calculate the total lifecycle cost, $TLCC$, which is the present value of project costs over its life N discounted at rate d:

$$TLCC = \sum_{n=0}^{N} \frac{C_n}{(1+d)^n}$$

The following equation shows the relationship between the LCOE and TLCC:

$$\sum_{n=1}^{N} \frac{Q_n \times LCOE}{(1+d)^n} = TLCC$$

Combining the two equations above gives:

$$\sum_{n=1}^{N} \frac{Q_n \times LCOE}{(1+d)^n} = \sum_{n=0}^{N} \frac{C_n}{(1+d)^n}$$

Notes.

The analysis period on the Financing page is equivalent to the project lifetime N.

The annual cost C_n includes the effect of inflation, so the nominal discount rate is the correct form to use on the right side of the equation.

The correct form of the discount rate on the left side of the equation depends on whether the LCOE is a real or nominal value.

The summation in the left hand term begins at n = 1, which is the first year that the system produces energy. The right hand summation begins at n = 0 to include investment costs in the calculation.

Solving for LCOE gives:

$$LCOE = \frac{\sum_{n=0}^{N} \frac{C_n}{(1+d)^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+d)^n}}$$

Note. This equation makes it appear that the energy term in the denominator is discounted. That is a result of the algebraic solution of the equation, not an indication of the physical performance of the system.

LCOE for Residential and Commercial Financing

For a project using either the residential or commercial (except Commercial PPA) financing option, the LCOE is the cost of financing, installing, and operating a system per unit of electricity it generates over the analysis period, accounting for incentives and salvage value. (This differs from the LCOE for commercial PPA and utility financing options, which includes a margin for profits defined by the internal rate of return (IRR) that is not available for residential or commercial projects.)

Note. For the Residential and Commercial financing options, the retail electricity prices from the Utility Rate page do not affect the LCOE. The LCOE is a measure of the cost of installing and operating the system, not of the value of electricity purchases avoided by the system. The project NPV is a measure of both the project costs and energy value.

For residential and commercial projects, you can compare a project's LCOE to the electricity rate that the residence or commercial entity would pay to an electric service provider if the project were not installed.

For the real LCOE, the real discount rate appears in the denominator's total energy output term:

$$\text{Real LCOE} = \frac{-C_0 - \dfrac{\sum_{n=1}^{N} C_{AfterTax,n}}{(1-d_{nominal})^n}}{\dfrac{\sum_{n=1}^{N} Q_n}{(1-d_{real})^n}}$$

Similarly, for the nominal LCOE, the nominal discount rate appears in the denominator's total energy output term:

$$\text{Nominal LCOE} = \frac{-C_0 - \dfrac{\sum_{n=1}^{N} C_{AfterTax,n}}{(1-d_{nominal})^n}}{\dfrac{\sum_{n=1}^{N} Q_n}{(1-d_{nominal})^n}}$$

Where,

Q_n (kWh)	Electricity generated by the system in year n shown in the Energy row in the project cash flow. The performance model calculates this value based on weather data and system performance parameters. It includes the effect of factors that you specify on the Performance Adjustment page.
N	Analysis period in years as defined on the Financing page
$C0$	The project's initial cost, shown in the Year zero column of the *After Tax Cost* row of the cash flow table.
$C_{AfterTax}$	The annual project cost in Year n, shown in the *After Tax Cost* row of the cash flow table.

Note. The "After Tax Cost" values in the cash flow table are different from the "After Tax Cashflow" values used in the project NPV equation. The cost does not include the value of electricity generated by the system.

d_{real}	The real discount rate defined on the Financing page. This is the discount rate without inflation. See LCOE Definition for an explanation of discount rates in the LCOE calculation.
$d_{nominal}$	The nominal discount rate shown on the Financing page. This is the discount rate with inflation.

LCOE for Utility and Commercial PPA Financing

For a project with the commercial PPA or one of the utility financing options, the LCOE represents the amount that the project must receive for each unit of electricity it sells to cover financing, installation, and operating costs, and to meet the financial constraints on the Financing page, accounting for salvage value and incentives.

SAM assumes that these projects are power generation projects installed on the utility side of consumer power meters. The projects sell electricity at a price negotiated by the project and electricity purchaser.

For these projects, the LCOE is effectively a levelized *price* of electricity because it is based on the present worth of the project's revenue stream, which you can see in the project cash flow as either

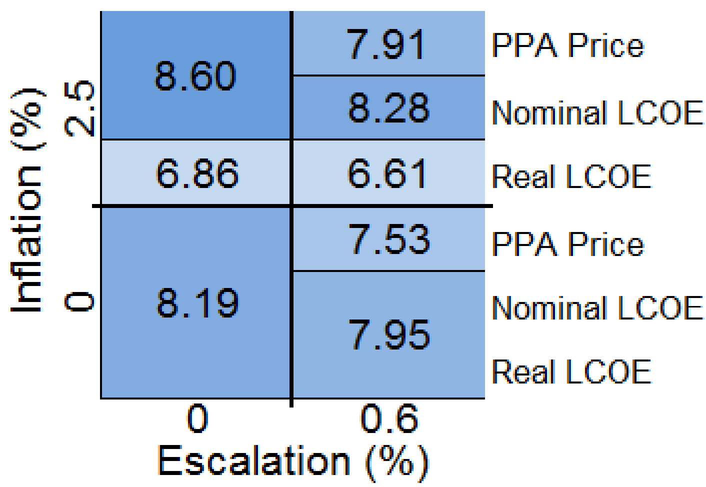
Energy Value for

- Commercial PPA,
- Utility IPP,

or *Total PPA Revenue* for

- Single Owner,
- All Equity Partnership Flip,
- Leveraged Partnership Flip,
- Sale Leaseback.

The following table shows the relationship between PPA price, nominal LCOE, and real LCOE. It is for a 64 MW sample wind farm that generates 176 GWh of electricity in its first year with a total installed cost of $2,000/kW and a 2.2 cent/kWh production tax credit. The shades of color in the table show the relative magnitude of the values (higher values are darker than lower values):



The table shows the following:

- When the inflation rate and PPA price escalation rate are both zero, the PPA Price, nominal LCOE and real LCOE are equal.
- When the inflation rate is zero, the real and nominal LCOE are equal.
- When the PPA price escalation rate is zero, the PPA price and nominal LCOE are equal.

Note. Because the LCOE for the commercial PPA and utility financing options depends on the PPA price, it can be very sensitive to the values that you specify for the target PPA price or target IRR and other assumptions on the Financing page. In some cases, it is possible to specify constraints that make the project capital investment a relatively insignificant factor in the LCOE calculation.

SAM uses the real and nominal discount rates from the Financing page to calculate the present worth of future costs. The real discount rate accounts for the time value of money and the relative degree of risk for alternative investments.

For the real LCOE, the real discount rate appears in the denominator's total energy output term:

$$\text{real LCOE} = \frac{\sum_{n=1}^{N} \frac{R_n}{(1+d_{\text{nominal}})^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+d_{\text{real}})^n}}$$

Similarly, for the nominal LCOE, the nominal discount rate appears in the total energy output term:

$$\text{nominal LCOE} = \frac{\sum_{n=1}^{N} \frac{R_n}{(1+d_{\text{nominal}})^n}}{\sum_{n=1}^{N} \frac{Q_n}{(1+d_{\text{nominal}})^n}}$$

Where,

Q_n (kWh) Electricity generated by the project in year *n*, calculated by the performance model based on weather data and system performance parameters. The first year output is reported in the Metrics table on the Results page and in the year one column of the project cash flow. Year two and subsequent output is the first year output reduced by the amount specified for the **Year-to-year decline in output** rate on the Performance Adjustment page.

N Analysis period in years as defined on the Financing page.

R_n Project revenue from electricity sales in year *n* , equal to the system's annual electric output multiplied by the annual PPA price. For the commercial PPA and utility IPP financing options, SAM displays the value in the cash flow as *Energy Value*, for the single owner, partnership flip, and sale leaseback options, as *Total PPA Revenue*.

d_{real} The real discount rate defined on the Financing page. This is the discount rate without inflation. See LCOE Definition for an explanation of discount rates in the LCOE calculation.

$d_{nominal}$ The nominal discount rate shown on the Financing page. This is the discount rate with inflation.

Replicating LCOE Calculations in Excel

If you would like to better understand SAM's LCOE calculations, you can follow the procedures described below to replicate the calculations using a spreadsheet program.

You can also use the **Send to Excel with Equations** button to create a spreadsheet populated with Excel formulas that replicate SAM's calculations.

For the residential, commercial, commercial PPA, and utiilty IPP financing options, you can download the spreadsheets on the Financial Models page of the SAM website (https://sam.nrel.gov/financial) to see how

SAM calculates the LCOE and NPV.

> **Note for Mac users.** SAM can not exchange data with Microsoft Excel on Mac computers. This means that the Excel Exchange feature is disabled on Mac versions of the software, and that SAM cannot directly export data to Excel workbooks.
>
> To use the SAM data in Excel or another spreadsheet program, you can export the data to a comma-separated text file (CSV), and then import the CSV file to the spreadsheet program.

To replicate LCOE calculation in Excel:

1. On the Results page, click **Cash Flows** to display the project cash flow.
2. Click **Send to Excel** to export the cash flow table to an Excel worksheet, or click **Save as CSV** to save the data as a text file then open it in Excel.
3. Type the project's discount rate and inflation rates as percentages into two blank cells in the worksheet. You can find these values on SAM's Financing page.
4. Type the following formula into a third empty cell to calculate the nominal discount rate:

   =(1+[inflation rate])(1+[real discount rate])-1*

   Replace the words in brackets with cell references to the appropriate values in the worksheet.

   This value should be equivalent to the nominal discount rate that SAM displays as a calculated value on the Financing page.
5. Type the following formula into a blank cell to calculate the real LCOE:

   =NPV([nominal discount rate],[energy value or total ppa revenue])/NPV([real discount rate],[energy])

   The energy value and energy are series of values from Year One to the final year in the analysis period. Energy is in the first row at the top of the table, and energy value is in the third row.
6. Use the following formula to calculate the nominal LCOE:

   =NPV([nominal discount rate],[energy value or total ppa revenue])/NPV([nominal discount rate],[energy])

> **Notes.**
>
> You can also replicate the calculations in Excel using the summations shown in the equations above in place of the NPV formulas.
>
> The Cash Flows table displays the intermediate values for the LCOE calculation in the rows under the heading "LCOE," near the top of the table for the residential, commercial, utility IPP, and commercial PPA financing options, and near the middle of the table for the single owner, leveraged partnership flip, all equity partnership flip, and sale leaseback options.

18.1 Minimum DSCR
0

The minimum DSCR is the minimum debt-service coverage ratio that SAM calculates for projects with the Commercial PPA or Utility IPP financing option that you choose on the Technology and Market window.

Note. For the advanced utility financing options with project debt (single owner and leveraged partnership flip) SAM assumes a constant coverage ratio that you specify on the Financing page.

The debt-service coverage ratio in each year n is the ratio of operating income to expenses in that year (SAM displays these values in the cash flow table):

$$\mathrm{DSCR}_n = \frac{R_n - C_{\mathrm{Operating},n}}{C_{\mathrm{Interest},n} + C_{\mathrm{Principal},n}}$$

Where,

$DSCR_n$	Debt service coverage ratio in year n shown in the *PreTax Debt Service Coverage Ratio* row of the cash flow.
R_n ($)	The required revenue in year n, shown in the *Revenues* row of the cash flow table, equal to the product of the electric output and electricity sales price in year n. Note that the electricity sales price in Year One is equal to the PPA price, and in subsequent years ($R_{1<n<=N}$) is equal to the PPA price adjusted by the PPA escalation rate defined on the Financing page.
$C_{Operating,n}$ ($)	The total operating costs in year n, shown in the *Operating Costs* row of the cash flow.
$C_{Interest,n}$ ($)	The loan interest payment in year n, shown in the *Debt Interest Payment* row of the cash flow.
$C_{Principal,n}$ ($)	The loan principal payment in year n, shown in the *Debt Repayment* row of the cash flow.

In SAM, the project's debt service coverage ratio (reported in results as the Minimum DSCR) is the lowest value of the $DSCR$ that occurs in the life of the project N, equivalent to the Analysis Period on the Financing page.

$$\text{minimum DSCR} = \min_{n \in [1,N]} \mathrm{DSCR}_n$$

Where,

minimum DSCR	The minimum debt service coverage ratio, reported as a result in the Metrics table.
$DSCR_n$	Debt service coverage ratio in year n shown in the *PreTax Debt Service Coverage Ratio* row of the cash flow. (The symbol *min* represents the function that searches for the minimum value of the DSCR in the cash flow.)

SAM calculates the minimum debt-service coverage ratio to be greater than or equal to the minimum required DSCR target defined on the Financing page.

18.1 Net Present Value (NPV)
1

A project's net present value (NPV) is a measure of a project's economic feasibility that includes both revenue (or savings for residential and commercial projects) and cost. In general, a positive net present value indicates an economically feasible project, while a negative net present value indicates an economically infeasible project, although this may not be true for all analyses.

For more information about using the net present value and other economic metrics to evaluate renewable energy projects, see pages 39-42 of Short W et al, 1995. *Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies. National Renewable Energy Laboratory.* NREL/TP-462-5173. http://www.nrel.gov/docs/legosti/old/5173.pdf

The NPV is the present value of the after tax cash flow discounted to year one using the nominal discount rate:

$$\mathrm{NPV} = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1 + d_{nominal})^n}$$

Where $C_{AfterTax}$ is the after tax cash flow in Year n, shown in the *After Tax Cash Flow* row of the cash flow table, N is the analysis period in years that you specify on the Financing page, and $d_{nominal}$ is the nominal discount rates from the Financing page.

> **Note.** In the project cash flow, SAM reports an "NPV of Energy Value" for commercial PPA and utility financing options, and "NPV of After Tax Costflow" for residential and commercial financing options. These NPV values are used in the levelized cost of energy (LCOE) equation, and are not the same as the project net present value reported in the Metrics table.

Depending on the financing option, the after-tax cash flow is either from the project perspective,

- Residential
- Commercial
- Commercial PPA
- Utility IPP
- Single Owner

from the perspective of each of the partners,

- All Equity Partnership Flip
- Leveraged Partnership Flip

or parties,

- Sale Leaseback

18.1 Payback Period 2

The payback period is the time in years that it takes for project savings in years two and later of the cash flow described below to equal the investment cost in year zero.

SAM considers the value of electricity generated by the system, tax benefits, and incentives to be project savings. The investment cost is the total installed cost less any investment-based incentives (IBI) or capacity-based incentives (CBI).

Notes.

SAM calculates the payback period for commercial and residential projects only.

A payback period of 1e+99 indicates that the payback period is greater than the analysis period. A negative payback period indicates that the sum of IBI and CBI incentives is greater than the project's total installed cost.

SAM calculates the payback period using nominal, or non-discounted cash flow values.

There are two ways to reduce the payback period: Decrease the installation cost (or increase IBI or CBI amounts), and increase project tax savings (or decrease operating expenses).

For more information about using the payback period and other economic metrics to evaluate renewable energy projects, see Short W et al, 1995. *Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies. National Renewable Energy Laboratory*. NREL/TP-462-5173. http://www.nrel.gov/docs/legosti/old/5173.pdf

You can download workbooks that replicate SAM's payback period calculation from the Financial Models page on the SAM website.

Cash Flow for Payback Calculation

SAM uses the values from the cash flow described below to calculate the payback period.

For the purposes of calculating the payback period, the cash flow in Year zero is the investment cost, and is equal to the sum of investment-based incentive (IBI) and capacity-based incentive (CBI) amounts specified on the Incentives page, less the total installed cost from the System Costs page. A negative value indicates a net outflow:

Year Zero = Total IBI
+ Total CBI
- Total Installed Cost

Note. If you specify that the IBI and CBI are taxable incentives on the Cash Incentives page, the incentives reduce the Year zero cost, but increase the Year one taxes (reducing the tax savings). In some cases, if you increase the IBI and CBI amounts, you may not see the reduction in payback period that you expect.

For the residential standard loan option:

Year n>0 = Energy Value

+ State Tax Savings
+ Federal Tax Savings
+ Total PBI
- Total Operating Expenses

For the residential mortgage option, debt interest payments are tax deductible and are included in the state and federal tax savings amounts, so SAM subtracts tax on debt to remove the effect of debt from the payback period equation:

Year n>0 = Energy Value
+ State Tax Savings
+ Federal Tax Savings
+ Total PBI
- Debt Interest Payment × Effective Tax Rate
- Total Operating Expenses

For commercial financing, both the energy value and debt interest payments are tax deductible:

Year n>0 = Energy Value × (1 - Effective Tax Rate)
+ State Tax Savings
+ Federal Tax Savings
+ Total PBI
- Debt Interest Payment × Effective Tax Rate
- Total Operating Expenses

The effective tax rate is a single number that includes both the federal income tax rate and state income tax rate:

Effective Tax Rate = Federal Tax Rate × (1 - State Tax Rate) + State Tax Rate

The federal and state tax rates are input variables on the Financing page.

Payback Period and Debt

As described above, the payback period depends on the project investment cost (sum of IBI and CBI minus total installed cost).

For projects with debt financing, the loan parameters specified on the Financing page do not affect the payback period because:

- The loan amount does not affect the project total installed cost or the value of IBI or CBI.
- The *Debt Interest Payment × Effective Tax Rate* term in the cash flow equations above effectively remove the tax on debt interest from the payback period calculation for Years One and later. As the cash flow equations for State and Federal income tax show, the tax on debt interest is included in the tax savings amounts. SAM subtracts the amount from the payback cash flow equation to remove the effect of debt from the payback period equation.

18.1 3 PPA Price

The PPA price is the power purchase bid price for projects with one of the Utility financing options, or with the Commercial PPA financing option. SAM assumes that these projects sell electricity at a price negotiated through a power purchase agreement (PPA).

Notes.

When you specify an escalation rate on the Financing page, the PPA price increases from year to year. The PPA price does not increase with inflation.

SAM reports the PPA price in the cash flow as "Energy Price" for Utility IPP and Commercial PPA, and as "PPA Price" for the advanced Utility financing options.

When your analysis involves time-of-delivery (TOD) factors, the PPA Price in Year One of the project cash flow is different from the PPA price in the Metrics table. See below for details.

PPA Price and Solution Mode

The PPA price in the Metrics table is either the value that you specify on the Financing page, or a value that SAM calculates based on the target internal rate of return (IRR) that you specify:

- When the solution mode on the Financing page is **Specify PPA Price**, the PPA price is the value that you specify.
- When the solution mode is **Specify IRR Target**, SAM uses an iterative search algorithm to find the PPA price required for project revenues to meet the minimum required IRR that you specify on the Financing page:

  Find PPA Price such that IRR >= Minimum Required IRR

  For projects with the Utility IPP financing option, the Financing page includes two optional constraints on the PPA price, "Require a minimum DSCR" and "Require a positive cash flow:"

  Find PPA Price such that IRR >= Minimum Required IRR,
  and Min DSCR >= Minimum Required DSCR (optional),
  and Cash Flow in Year n > 0 (optional)

PPA Price and TOD Factors

Time-of-delivery (TOD) factors allow the power price to vary with time within the structure of a power purchase agreement with a single bid price. The agreement consists of a PPA price and a set of factors and periods.

The PPA price that SAM reports in the Metrics table is equivalent to the bid price. When you choose **Specify PPA Price** for the **Solution Mode** on the Financing page, the PPA price in the Metrics table is the same as the price you specify on the Financing page.

For analyses without TOD factors, the PPA price (bid price) in the Metrics table is equal to the *PPA Price* in Year One (or *Energy Value* in Year One for the Utility IPP and Commercial PPA financing options) of the cash flow.

For analyses involving PPA price time-of-delivery (TOD) factors, the PPA Price (bid price) is not equal to the

PPA Price in Year One (or *Energy Value* in Year One for the Utility IPP and Commercial PPA financing options) of the cash flow. For these analyses, for each hour of the year, SAM multiplies the PPA bid price by the TOD factor to calculate a set of hourly energy prices for Year one, and then reports the average of the 8,760 hourly values as the annual *PPA Price* (*Energy Price*) in Year one.

You can specify the TOD factors and hours that they apply on the Thermal Energy Storage page for CSP systems, or on the Time of Delivery Factors page for PV and other systems. (To remove TOD factors from your analysis, set the value to 1 for all periods.)

18.14 PPA Price Escalation

The PPA escalation rate is an annual escalation rate that SAM uses to calculate the PPA price in Years Two and later of the cash flow:

PPA Price in Year n>1 = PPA Price in Year n=1 × (1 + PPA Price Escalation) ^ n

The PPA escalation rate is an input that you specify on the Financing page.

For the Utility IPP financing option, if you check the *Automatically minimize LCOE with respect to PPA Escalation Rate* option on the Financing page, SAM finds the PPA escalation rate that results in the lowest levelized cost of energy instead of using an input value that you specify.

18.15 Real Estate Value Added

The real estate value added is an annual dollar amount that SAM calculates for the residential and commercial financing option as an estimate of the value a renewable energy system might add to the property value of the building on which it is installed. The value added estimate is based on the dollar value of the electricity the system generates.

The real estate value added variable is available in Tables on the Results page, under **Annual Data**.

SAM uses the method from California Energy Commission's Solar Advantage Value (SAVE) web calculator: http://www.gosolarcalifornia.org/tools/save.php.

The real estate value added for each year is the present worth of the annual energy value for the current and future years. For the last year in the analysis period, the real estate added value is the sum of the energy value for that year and the salvage value from the Financing page.

19 Performance Metrics

SAM displays performance metrics on the Results page after running simulations.

For a general description of the Metrics table, see Metrics Table.

For a list of performance metrics with links to descriptions, see Performance Metrics Overview.

The performance metrics are:

- Annual Biomass Usage
- Annual Energy
- Annual Water Usage
- Aux with and without Solar (kWh)
- Capacity Factor
- First year kWh/kW
- Gross to Net Conv Factor
- Heat Rate
- Plant Capacity
- Pump Power
- Resource Capability
- Solar Fraction
- System Performance Factor
- Thermal Efficiency

19.1 Performance Metrics Overview

The performance metrics are values that SAM calculates from the hourly performance model results and, for some variables such as capacity factor, the system specifications.

After running simulations, SAM displays the performance metrics on the Results page:

- Metrics table
- Tables, under **Metrics** (with additional variables under **Single Value**)
- Graphs, with the **Single Value** option for **X Value**, or with parametric or other analysis options that involve input variables with multiple values.

> **Note**. SAM may use slightly different names for the metrics, depending on the model options and where it displays the metric. For example, "net annual energy" may also appear as "annual energy."

SAM displays different metrics depending on the performance model that you specify on the Technology and Market window.

The annual energy value appears for all of the performance models.

Performance Metrics: Solar Technologies

The solar performance model abbreviations used in the following table are:

- PVW: PVWatts
- PVFP: Flat Plate PV
- HCPV: High-X concentrating PV
- TRP: Parabolic Trough - Physical
- TRE: Parabolic Trough - Empirical
- PTMS: Power Tower - Molten Salt
- PTDS: Power Tower - Direct Steam
- LF: Linear Fresnel
- DS: Dish Stirling
- GSS: Generic Solar System
- SWH: Solar Water Heating

Table 18. Performance model metrics for solar technologies.

Metric	PVW	PVFP	HCPV	TRP	TRE	PTMS	PTDS	LF	DS	GSS	SWH
Capacity Factor	•	•	•	•	•	•	•	•	•	•	•
First year kWh/kW	•	•									•
System Performance Factor		•									
Land Area		•		•	•	•	•	•			
Gross to Net Conv Factor				•	•	•	•	•		•	
Annual Water Usage				•		•	•	•			
Aux With Solar (kWh)											•
Aux Without Solar (kWh)											•
Solar Fraction											•

Performance Metrics: Non-solar Technologies

The non-solar performance model abbreviations used in the following table are:

- GS: Generic System
- WP: Wind Power
- GP: Geothermal Power
- GCP: Geothermal Co-production
- BP: Biomass Power

Table 19. Performance model metrics for non-solar technologies.

Metric	GS	WP	GP	GCP	BP
First year kWh/kW		•			
Land Area		•			
Capacity Factor	•	•	•	•	•
Plant Capacity				•	
Resource Capability				•	
1st Year Energy Production (kWh)			•		
Plant Lifetime Output (kWh)			•		
Average Annual Output (kWh)			•		
Pump Power (MW)			•		
Annual biomass usage (dry tons/yr)					•
Gross Heat Rate (MMBtu/MWh)					•
Net Heat Rate (MMBtu/MWh)					•
Thermal Efficiency, HHV (%)					•
Thermal Efficiency, LLV (%)					•

19.2 Annual Biomass Usage

For the biomass power model, Annual Biomass Usage is the annual biomass feedrate, equal to the total obtainable biomass resource from the Feedstock page.

SAM uses the value to calculate the system's heat rate and thermal efficiency.

19.3 Annual Energy

SAM reports the total quantity of electricity generated by the system in Year one of the project cash flow and reports it in the Metrics table.

- For projects with the commercial PPA or one of the utility financing options, SAM assumes that all of the electricity is sold to the grid at the PPA price.
- For residential and commercial projects, some of the electricity generated by the system meets a building or facility load that you specify on the Electric Load page, and some is sold to the grid at the retail rates you specify on the Utility Rate page.

Annual Energy, kWh/year

All performance models except solar water heating systems.

Annual Energy = Sum of Hourly Energy Delivered × *Percent of Annual Output*

Where *Percent of Annual Output* is from the Performance Adjustment page.

Annual Energy Saved, kWh/year

For solar water heating systems, the annual energy saved is the electrical energy the project avoids purchasing due to the solar water heating system.

Annual Energy Saved = (Aux Without Solar - Aux With Solar - Pump Power) × *Percent of Annual Output*

Where *Percent of Annual Output* is from the Performance Adjustment page.

19.4 Annual Water Usage

For physical trough, power tower, and linear Fresnel systems, SAM reports the total annual water consumption in cubic meters for cooling and mirror washing.

Annual Water Usage

Annual Water Usage (m^3) = Cooling Water Usage (m^3) + Mirror Washing Water Usage (m^3)

The mirror washing water usage is based on the mirror washing parameters you specify on the Solar Field or Heliostat Field page:

Mirror Washing Usage = Water Usage per Wash (L/m^2, aperture) × *Total Aperture or Reflective Area (m^2)* × *Washes per Year (1/year)*

SAM reports the annual mirror washing usage as a Single Values variable in Tables and Graphs. It also reports the cooling water flow rate in Tables as an hourly variable ("water makeup flow rate" or "water consumption mass flow rate").

19.5 Aux with and without Solar (kWh)

The Solar Water Heating Model calculates the annual energy savings by a solar water heating system designed to meet the hourly hot water heating load defined by the hot water draw on the SWH System page. To do so, SAM calculates the following quantities, which you can see in the Tables on the Results page:

- Solar energy delivered to the water heater, *Q Collector to Tank*
- Electrical energy required to meet the remaining water heating load, *Auxiliary with SHW*
- Electrical energy required for a standard electric water heater with no solar system, *Auxiliary without SHW*
- Hourly electric pump power for the solar water heating system, *Pump Power*

Aux With Solar

The energy supplied by the auxiliary electric water heating system to supplement energy from the solar collectors.

Aux Without Solar

The energy that would be required from a standard electric hot water system if the solar system were not present.

19.6 Capacity Factor

The capacity factor is the ratio of the system's predicted electrical output in the first year of operation to the nameplate output, which is equivalent to the quantity of energy the system would generate if it operated at its nameplate capacity for every hour of the year. For PV systems, the capacity factor is an AC-to-DC value. For other systems, the capacity is an AC-to-AC value.

Capacity Factor = Net Annual Energy (kWhac/yr) / System Capacity (kWdc or kWac) / 8760 (h/yr)

Where *Net Annual Energy* is the total annual electric generation in the first year of operation, accounting for the factors from the Performance Adjustment page, and System *Capacity* is the system's nameplate capacity (see table below). For PV systems the capacity is in DC kW, for other system systems, the capacity is in AC kW.

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 20. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle

CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

19.7 First year kWhac/kWdc

For PV systems, SAM reports the ratio of the system's annual AC electric output in Year one to it's nameplate DC capacity:

First year kWhac/kWdc = Net Annual Energy ÷ Nameplate Capacity

Where *Net Annual Energy* is the total annual electric generation in the first year of operation accounting for the factors from the Performance Adjustment page, and *Nameplate Capacity* is the system's DC nameplate capacity from the Array page for the Flat Plate PV model and the PVWatts Solar Array page for the PVWatts model.

19.8 Gross to Net Conv Factor

For CSP systems, SAM displays the ratio of the system's annual AC electric output to the power block's gross electric output. The difference between the two is due to parasitic losses from electric loads in the solar field and power block for pumps, cooling equipment, etc.

Gross to Net Conv Factor = Net Electric Output (kWh) / Gross Electric Output (kWh)

Where *Net Electric Output* and *Gross Electric Output* are reported under Single Values in the Tables.

19.9 Heat Rate and Thermal Efficiency

For biomass power systems, SAM reports the heat rate and thermal efficiency values from the system's net annual energy value calculated by the performance model, and the biomass feed rate and overall feedstock heating values from the Feedstock page.

> **Note.** The heat rate and thermal efficiency values are based on the annual energy value calculated by the performance model, before the performance adjustment factors are applied.

Gross Heat Rate, MMBtu/MWh

Gross Heat Rate (MMBtu/MWh) = Dry Biomass Feed Rate (lb/year) × Average Overall Feedstock HHV (MMBtu/lb) ÷ Net Annual Energy (MWh/year) ÷ Percent of Annual Output Factor

Net Heat Rate, MMBtu/MWh

Net Heat Rate (MMBtu/MWh) = Dry Biomass Feed Rate (lb/year) × Average Overall Feedstock LLV (MMBtu/lb) ÷ Net Annual Energy (MWh/year) ÷ Availability Factor

The dry biomass feed rate is the annual feed rate from the Feedstock page (and also shown as Annual Biomass Usage in the Metrics table) converted from ton/year to lb/year (2000 lb = 1 ton), the average overall feedstock heating values are from the Feedstock page, converted from Btu/lb to MMBtu/lb (1,000,000 Btu = 1 MMBtu), Net Annual Energy is from the Metrics table, and Availability Factor is from the Performance Adjustment page.

Thermal Efficiency HHV, %

Thermal Efficiency HHV (%) = 341.23 (MMBtu/MWh) ÷ Gross Heat Rate (MMBtu/MWh)

Thermal Efficiency LHV, %

Thermal Efficiency LHV (%) = 341.23 (MMBtu/MWh) ÷ Net Heat Rate (MMBtu/MWh)

Where 341.23 MMBtu/MWh is the conversion factor between MMBtu and MWh units, and the heat rates are the values described above.

19.10 Plant Capacity

For geothermal co-production systems, SAM reports the plant's capacity, which is equal to the resource power potential value on the Resource and Power Generation page.

19.11 Pump Power

For geothermal power systems, SAM reports the pump power, which is equal to the pump work value on the Plant and Equipment page.

19.12 Resource Capability

For geothermal co-production systems, SAM reports the plant's resource capability, which is equal to the resource power potential value on the Resource and Power Generation page.

19.13 Solar Fraction

For solar water heating systems, the solar fraction is the ratio of solar energy to total energy delivered to the water storage tank. The solar fraction is based on the energy values for year one of the project cash flow.

Solar Fraction

Solar Fraction = Total Solar Energy Delivered to Tank (kWh/year) ÷ Total Energy Delivered to Tank (kWh/year)

Where

Total Solar Energy Delivered to Tank (kWh) = Total Q Collector to Tank (kWh/year) + Aux With Solar (kWh/year)

and *Total Q Collector to Tank* is the sum of the hourly *Q Collector to Tank* values.

19.14 System Performance Factor

The system performance factor is a measure of a photovoltaic system's annual electric generation output in AC kWh compared to its nameplate rated capacity in DC kW, taking into account the solar resource at the system's location.

Note. SAM only calculates the system performance factor for the Flat Plate PV model. It does not calculate the value for the PVWatts or High-X Concentrating PV models, or for the other technologies.

System Performance Factor

System Performance Factor = Annual Energy (kWh) ÷ (Input Radiation (kWh) × Module Efficiency (%))

Where *Annual Energy* is the system's total net AC output in Year One reported in the Metrics table, *Input Radiation* is the product of the total radiation incident on the array and the total area of modules, and *Module Efficiency* is the nominal efficiency of the modules in the array at standard test conditions STC.

To see the values used in this calculation, after running simulations, on the Results page, click **Tables**. Under **Single Values** click **Input Radiation (kWh)** and **Net ac output (kWh)**. The module efficiency is from the Module page.

The method used to calculate the photovoltaic system performance factor is described in the SMA technical bulletin *Performance Ratio: Quality Factor for the PV Plant, Perfratio-UEN100810 Version 1.0*.

20 Cash Flow Variables

SAM displays the cash flow variables in the Cash Flows table on the Results page, and Tables.

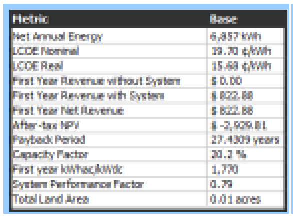
Note. If you are looking for the description of a specific variable in the cash flow table, click the link below for the financial model you are using, and then search the page for the variable name.

SAM displays a different set of cash flow variables depending on the Financing option:

- Residential and Commercial
- IPP and Commercial PPA
- Single Owner
- All Equity Partnership Flip
- Leveraged Partnership Flip
- Sale Leaseback

20.1 Residential and Commercial

This topic describes the cash flow table generated by the financial model for the residential and commercial financing options. See Financing Overview for details.



Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

SAM offers three options for exporting the cash flow table:

- **Copy to clipboard** copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.
- **Save as CSV** saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.
- **Send to Excel (Windows only)** creates a new Excel file that contains the data from the cash flow table in an Excel file, but no formulas.

- **Send to Excel with Equations (Windows only)** exports the cash flow data to an existing Excel workbook that contains formulas to illustrate how SAM's internal cash flow calculations work. The workbooks are in the *\exelib\spreadsheets\equations* folder of your SAM installation folder.

> **Notes**.
>
> SAM makes cash flow calculations internally during simulations. It does not use Excel to make the calculations. The two **Send to Excel** options are to help you analyze the cash flow data and understand how SAM's internal calculations work.
>
> You can also display cash flow data by building a Table. This option allows you to choose the rows to include in the table, and also makes it possible to show cash flow results from a parametric analysis.

Cash Flow Year

The cash flow year is displayed in the top row of the cash flow table. In the descriptions below, the letter *n* indicates the cash flow year, where *n = 0* is Year Zero of the cash flow, *n = 1* is year one, *n = 2* is year two, etc.

Energy (kWh)

For systems that generate electricity, *Energy* is the total amount of electricity generated by the system in AC kilowatt-hours for each year.

For solar water heating systems, *Energy* is the amount of electricity saved by the solar water heating system in AC kilowatt-hours for each year.

The performance model runs hourly or sub-hourly simulations to calculate the total annual energy value, which the financial model considers to be energy value for in Year One of the cash flow. SAM adjusts that value using the factors you specify on the Performance Adjustment page to account for expected system downtime for maintenance, and degradation of system performance over time.

> **Note.** The annual energy value reported for Year one in the cash flow is not equal to the sum of the hourly energy values because the hourly values do not account for the **Percent of annual output** factor from the Performance Adjustment page.

For Year One, *Energy* is the value is calculated by the performance model:

Energy in Year One = Sum of Simulation Values x Percent of Annual Output

Where *Sum of Simulation Values* is the system's total annual electrical output (or energy saved) equal to the sum of the values calculated by the performance model (8,760 values for hourly simulations), and *Percent of Annual Output* is from the Performance Adjustment page.

Notes.

If you specify *Availability* on the Performance Adjustment page using the annual schedule option, SAM applies the value you specified for each year to the Year One Energy value:

Energy in Year n>1 = Energy in Year One × Availability in Year n

The Geothermal Power performance model runs simulations for each year of the analysis period rather than only for Year One. For the Geothermal Power model:

Energy in Year n = Energy in Year n × Availability in Year n

For Years 2 and later:

Energy in Year n>1 = Energy in Year n-1 × (1 - Year-to-Year Decline in Output)

Where *Energy in Year n-1* is the previous year's energy value and *Year-to-Year Decline* is from the Performance Adjustment page.

Note. If you specified **Year-to-year decline in output** on the Performance Adjustment page using the annual schedule option, SAM applies the value as follows (after applying the appropriate availability factor to calculate the Year One energy value):

Energy in Year n>1 = Energy in Year n × (1 - Year-to-Year Decline in Output in Year n)

Energy Value ($)

The energy value is the value of electricity that the project avoids purchasing because of the renewable energy system. The energy value in Year 1 is equal to the Net savings with system reported in the Metrics table.

The energy value in Years 2 and later is the Year 1 value adjusted by the inflation rate from the Financing page, and the Out-year Escalation rate from the Utility Rate page.

LCOE

The LCOE rows in the cash table show how SAM calculates the real and nominal levelized cost of energy (LCOE) values reported in the Metrics table.

NPV of After Tax Costflow - Nominal ($)

The present worth of the after-tax cost flow, representing total cost of installing and operating the system over the project analysis period:

NPV of After Tax Cost Flow Nominal = - [After Tax Cost in Year Zero
+ After Tax Cost in Year 1 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^1
+ After Tax Cost in Year 2 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^2
+ After Tax Cost in Year 3 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^3
+ …
+ After Tax Cost in Year N ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^N]

Where the analysis period *N* and *Nominal Discount Rate* are both on the Financing page, and the After Tax Cost in Year n is at the bottom of the cash flow table.

NPV of Energy - Nominal (kWh)

The present worth of the annual energy generated by the system, "discounted" at the nominal discount rate and representing the quantity in kWh of electricity generated by the system.

NPV of Energy Nominal = Energy in Year 1 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^1
+ Energy in Year 2 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^2
+ Energy in Year 3 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^3
+ ...
+ Energy in Year N ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^N

Where the analysis period *N* and *Nominal Discount Rate* are both on the Financing page, and *Energy* is described above.

LCOE - Nominal (cents/kWh)

The nominal levelized cost of energy:

LCOE Nominal (cents/kWh) = NPV of After Tax Costflow Nominal ($) ÷ NPV of Energy Nominal (kWh) * 100 (cents/$)

NPV of Energy - Nominal (kWh)

The present worth of the annual energy generated by the system, "discounted" at the real discount rate and representing the quantity in kWh of electricity generated by the system.

NPV of Energy Real = Energy in Year 1 ÷ (1 + Real Discount Rate (%) ÷ 100%)^1
+ Energy in Year 2 ÷ (1 + Real Discount Rate (%) ÷ 100%)^2
+ Energy in Year 3 ÷ (1 + Real Discount Rate (%) ÷ 100%)^3
+ ...
+ Energy in Year N ÷ (1 + Real Discount Rate (%) ÷ 100%)^N

Where the analysis period *N* and *Real Discount Rate* are both on the Financing page.

LCOE - Real (cents/kWh)

The real levelized cost of energy:

LCOE Real (cents/kWh) = NPV of After Tax Cashflow Nominal ($) ÷ NPV of Energy Real (kWh) * 100 (cents/$)

Operating Expenses

Operating expenses include O&M, insurance, and property tax payments. SAM also accounts for salvage value at the end of the analysis period as a negative operating expense.

O&M (Operation and Maintenance)

The annual operation and maintenance (O&M) costs are defined on the System Costs page and may be calculated as a fixed amount, a cost per system rated capacity, a cost per unit of energy output, or any combination of the three:

Fixed O&M Annual in Year n = Fixed Annual Cost ($/yr) × (1 + Inflation Rate + Escalation Rate) ^ n-1

*Fixed O&M in Year n = Fixed Cost by Capacity ($/kW-yr) × System Capacity * (1 + Inflation Rate + Escalation Rate)^(n-1)*

Variable O&M in Year n = Variable Cost by Generation ($/MWh) / 1000 (kWh/MWh) × Energy in

Year n (kWh) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where Fixed Annual Cost, Fixed Cost by Capacity, Variable Cost by Generation, and Escalation Rate are from the System Costs page, and Inflation Rate is from the Financing page.

Note. When you specify O&M costs using an annual schedule instead of a single value, SAM does not apply the inflation rate or escalation rate to the values you specify for each year.

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 21. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

Fuel

The following performance models include a fuel cost calculation:

- Parabolic trough (physical or empirical) with fossil backup
- Power tower with fossil backup
- Generic solar system with fossil backup

- Generic system for the primary fuel cost
- Biomass Power for biomass and supplementary coal feedstock costs

> **Note.** For the CSP systems listed above, SAM only considers the system to have a fossil-fired backup boiler when the fossil fill fraction variable on the Thermal Storage page is greater than zero.

For solar and generic systems listed above that consume a fuel, Fuel O&M is the annual fuel cost:

Fuel O&M in Year n = Annual Fuel Usage in Year One (kWh) × 0.003413 MMBtu per kWh × Fossil Fuel Cost ($/MMBtu) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Annual Fuel Usage in Year One* is the quantity of fuel consumed in Year One calculated by the performance model. *Fossil Fuel Cost* and *Escalation Rate* are from the System Costs page, and Inflation Rate is from the Financing page.

> **Note.** When you specify fuel costs using an annual schedule instead of a single value, SAM does not apply the inflation rate or escalation rate to the values you specify for each year.

For the biomass power model, SAM calculates feedstock and coal costs using feedstock usage and price values from the Feedstock Costs page:

Biomass Feedstock Costs in Year n = Total Biomass Fuel Usage in Year One (dry tons/year) × Biomass Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Coal Feedstock Costs in Year n = Total Coal Fuel Usage in Year One (dry tons/year) × Coal Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where the fuel usage and fuel costs are from the Feedstock Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

Insurance

The insurance cost applies in Year One and later of the cash flow:

Insurance in Year n = Total Installed Costs ($) × Insurance (%) × (1 + Inflation Rate)^(n-1)

Where *Total Installed Costs* is the value from the System Costs page, and Insurance and Inflation Rate are specified on the Financing page.

Property Assessed Value

The property assessed value is the value SAM uses as a basis to calculate the annual property tax payment:

Property Assessed Value in Year One = Assessed Value

Where *Assessed Value* is from the Financing page.

In Years 2 and later, the property assessed value is the Year One value adjusted by the assessed value decline value from the Financing page:

Property Assessed Value in Year n>1 = Assessed Value in Year One × [1 - Assessed Value Decline × (n-1)]

Where *Assessed Value Decline* is from the Financing page, expressed as a fraction instead of a percentage.

If the value of *1 - Assessed Value Decline* × *(n-1)* for a given year is equal to zero or less, then the *Property Assessed Value* in that year is zero.

Property Taxes

Property taxes apply in Year One and later of the cash flow:

Property Taxes in Year n = Property Assessed Value in Year n ($) × Property Tax (%)

Where *Property Assessed Value* is described above, and *Property Tax* is from the Financing page.

Net Salvage Value

SAM calculates the net salvage value using the percentage you specify on the Financing page and the total installed cost from the System Costs page. The salvage value applies in the final year of the project cash flow.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period

For residential projects, the salvage value has no effect on federal and state income tax because operating expenses are not taxable.

For commercial projects, because the salvage value reduces the operating expenses in the final year of the analysis period, it increases the federal and state income tax payment because operating expenses are deductible from federal and state income tax.

Operating Costs

The total operating costs include operation and maintenance costs, and insurance and property tax payments:

Operating Costs = Fixed O&M Annual + Fixed O&M + Variable O&M + Fuel + Insurance + Property Taxes - Salvage Value

Deductible Expenses

The deductible expenses are project costs that can be deducted from federal and state income taxes.

For residential projects, the deductible expense amount equals the property tax amount:

Deductible Expenses = - Property Taxes

For commercial projects, all operating costs are deductible:

Deductible Expenses = - Operating Costs

Financing

Debt Balance

The debt balance in Year One represents the debt portion of the investment costs, less incentives.

For residential and commercial:

Debt Balance in Year One = - (Total Installed Costs - Total IBI - Total CBI) × Debt Fraction

For commercial PPA and utility IPP:

Debt Balance in Year One = - (Total Installed Costs + Construction Financing Costs - Total IBI - Total CBI) × Debt Fraction

Where *Total Installed Costs* is from the System Costs page, *Total IBI* and *Total CBI* are the sums of all investment-based and capacity-based incentives specified on the Incentives page, and *Debt Fraction* is the value specified on the Financing page. *Construction Financing Costs* is from the Financing page.

In Years Two and later, the debt balance is calculated from the previous year's debt balance and debt repayment amounts:

Debt Balance in Year n>1 = Debt Balance in Year n-1 + Debt Repayment in Year n-1

Notes.

SAM shows the debt balance as a negative value to indicate net annual outflow. A value of zero indicates all debt is paid off.

The debt balance in Year One is different from the Principal Amount on the Financing page when your analysis includes either capacity-based or investment-based incentives.

Debt Interest Payment

The debt interest payment is the annual interest paid on debt:

Debt Interest Payment in Year n = - Debt Balance in Year n × Loan Rate

Where *Debt Balance* is described above, and *Loan Rate* is from the Financing page.

Debt Repayment

The debt repayment amount is the annual payment on principal amount assuming constant payments over the loan term. SAM calculates the amount using the levelized mortgage payment methodology equivalent to Excel's PPMT function:

Debt Repayment in Year n = -PPMT(Loan Rate,n,Loan Term,Principal Amount,0,0)

Where *Loan Rate*, *Loan Term*, and *Principal Amount* are from the Financing page.

Debt Total Payment

The total debt payment is the sum of interest and principal payments:

Debt Total Payment = Debt Interest Payment + Debt Repayment

Incentives

The incentive cash flow rows show the value of cash incentives and tax credits, which are used to calculate cash flows described above.

IBI (Investment Based Incentives)

Each IBI (federal, state, utility, other) applies in Year Zero of the project cash flow.

Because you can specify each IBI on the Incentives page as either an amount or a percentage, SAM calculates the value of each IBI as the sum of two values:

IBI as Amount = Amount

IBI as Percentage = Total Installed Cost ($) × Percentage (%), up to Maximum

IBI in Year 0 = IBI as Amount + IBI as Percentage

Where *Amount*, *Percentage* and *Maximum* are the values that you specify on the Incentives page, and *Total Installed Cost* is from the System Costs page.

Total IBI is the sum of the four IBI values (federal, state, utility, other).

Note. The IBI amount reduces the after tax cost flow in Year Zero, and the debt balance in Year One. This is because SAM assumes that debt payments begin in Year One, when the project is generating or saving electricity.

CBI (Capacity Based Incentives))

Each CBI (federal, state, utility, other) applies in Year Zero of the project cash flow:

CBI in Year 0 = System Capacity (W) × Amount ($/W), up to Maximum

Where System Capacity is the rated capacity of the system, and *Amount* and *Maximum* are the values you specify on the Incentives page.

Total CBI is the sum of the four CBI values (federal, state, utility, other).

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 22. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

PBI (Performance Based Incentive)

Each PBI (federal, state, utility, other) applies in Years One and later of the project cash flow, up to the number of years you specify:

PBI in Year n = Amount ($/kWh) × Energy in Year n (kWh) × (1 + Escalation)^(n-1), up to Term

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in Energy row of the cash flow table (described above).

Note. If you use an annual schedule to specify year-by-year PBI amounts, SAM ignores the escalation rate.

Total PBI is the sum of the four PBI amounts (federal, state, utility, other).

Important Note! If you specify a PBI amount on the Cash Incentives page, be sure to also specify the incentive term. If you specify a term of zero, the incentive will not appear in the cash flow table.

PTC (Production Tax Credit)

The state and federal PTC each apply in Year One and later of the project cash flow, up to the number of years you specify:

PTC in Year n = Amount ($/kWh) × (1 + Escalation)^(n-1) × Energy in Year n (kWh)

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in the Energy row of the cash flow table (described above).

SAM rounds the product *Amount ($/kWh) × (1 + Escalation)^(n-1)* to the nearest multiple of 0.1 cent as described in Notice 2010-37 of IRS Bulletin 2010-18.

Note. If you specify year-by-year PTC rates on the Incentives page using an Annual Schedule instead of a single value, SAM ignores the PTC escalation rate.

ITC (Investment Tax Credit)

The state and federal ITC each apply only in Year One of the project cash flow. For ITCs that you specify as a fixed amount:

ITC in Year One = Amount

Where *Amount* is the value you specify in the Incentives page.

For ITCs that you specify as a percentage of total installed costs:

ITC in Year One = (Total Installed Cost ($) - ITC Basis Reduction ($)) × Percentage (%), up to Maximum

Where *Total Installed Cost* is from the System Costs page, and *Percentage* and *Maximum* are the values you specify on the Incentives page.

ITC Basis Reduction applies only to the Commercial and Utility financing options, and depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked boxes under **Reduces Depreciation and ITC Bases**. For each IBI or CBI with a check mark, SAM subtracts the incentive amount from the total installed cost to calculate the ITC.

ITC Basis Reduction = IBI + CBI

Where *IBI* and *CBI* are the incentives that you have specified reduce the ITC basis on the Incentives page.

Tax Effect on Equity -- State

The tax effect on equity cash flows are the tax calculations for state income taxes. SAM makes the following state income tax assumptions:

- For the Residential and Commercial financing options, state taxable income is the sum of all incentive payments in a given year that you specify as State taxable on the Incentives page.
- For the Commercial financing option, income tax paid on the value of energy is accounted for in the after-tax cash flow described below. For the Residential option, income tax is not paid on the value of energy.
- The state tax rate is the value you specify on the Financing page.
- Investment-based incentives that appear in Year Zero of the cash flow are taxable in Year One.
- Project operating costs are tax deductible for both the Residential and Commercial financing options.
- Debt interest payments are deductible for the Residential option with a Mortgage type loan and for the Commercial option. Debt interest payments are not tax deductible for the Residential option with the Standard Loan type loan. You specify the residential loan type on the Financing page.

Depreciation (Commercial Only)

Depreciation applies only to the Commercial financing option, and depends on the depreciation schedule from the Depreciation page.

State Depreciation Schedule

For the Commercial financing option with a depreciation option defined on the Depreciation page, SAM displays the state depreciation percentage in the State Depreciation Schedule row of the cash flow table. SAM determines the depreciation schedule (percentage and applicable years) based on the options you specify for state depreciation on the Depreciation page.

For the Residential financing option, depreciation does not apply, and SAM displays zeros in the cash flow.

State Depreciation

The depreciation amount is the product of the depreciation percentage determined by the depreciation schedule described above, and the depreciable base:

Depreciation in Year n = Depreciation Schedule (%) in Year n × (Total Installed Costs - Depreciation Basis Reduction)

Where *Depreciation Schedule* is described above, and the *Total Installed Costs* is from the System Costs page.

Basis Reduction depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked **State** boxes in the **Reduces Depreciation and ITC Bases** column, or an investment tax credit (ITC) with checked **State** boxes in the **Reduces Depreciation Basis** column. For each IBI, CBI, or ITC with a check mark, SAM subtracts the total incentive amount and fifty percent of the tax credit amount from the total installed cost to calculate the depreciable base:

Depreciation Basis Reduction Year n = ITC × 0.5 + IBI + CBI + PBI

Where *ITC* includes all tax credits that you specified on the Incentives page to reduce the depreciation basis, and *IBI*, *CBI*, and *PBI* include all incentives you specified to reduce the depreciation basis.

For the Residential financing option, depreciation does not apply, and SAM displays zeros in the cash flow.

State Income Taxes

The state income tax is the annual income tax owed before accounting for tax credits. A negative value indicates a net tax liability (tax owed), and a positive value indicates a net tax benefit (tax refund).

State Income Taxes: Residential with Standard Loan

For the Residential financing option with the Standard Loan loan type on the Financing page, debt interest payments are not tax-deductible:

Income Taxes in Year One = State Tax Rate
× (Total IBI in Year Zero
+ Total CBI in Year Zero
+ Total PBI in Year One
+ Deductible Expenses in Year One)

Income Taxes in Year n>1 = State Tax Rate
× (Total PBI in Year n
+ Deductible Expenses in Year n)

State Income Taxes: Residential with Mortgage Loan

For the Residential financing option with the Mortgage loan type on the Financing page, debt interest payments are deducted:

Income Taxes in Year One = State Tax Rate
× (Total IBI in Year Zero
+ Total CBI in Year Zero
+ Total PBI in Year One
+ Deductible Expenses in Year One
- Debt Interest Payment in Year One)

Income Taxes in Year n>1 = State Tax Rate
× (Total PBI in Year n
+ Deductible Expenses in Year n
- Debt Interest Payment in Year n)

State Income Taxes: Commercial

For the Commercial financing option, SAM includes a depreciation deduction in the tax equation:

Income Taxes in Year One = State Tax Rate
× (Total IBI in Year Zero
+ Total CBI in Year Zero
+ Total PBI in Year One
+ Deductible Expenses in Year One
- Debt Interest Payment in Year One
- State Depreciation in Year One)

Income Taxes in Year n>1 = State Tax Rate
× (Total PBI in Year n
+ Deductible Expenses in Year n
- Debt Interest Payment in Year n
- State Depreciation in Year n)

Notes.

Because of the way it is defined, *Deductible Expenses* is negative when it represents a reduction in taxes, and so is an addition in the taxable income equation rather than a subtraction.

For the Residential and Commercial financing options (except Commercial PPA), SAM assumes that electricity generated by the project displaces electricity that would have been purchased from the grid without the system. Therefore, SAM does not consider electricity sales for residential and commercial projects to be taxable income.

State Tax Savings

The net tax savings, accounting for income taxes and tax credits:

State Tax Savings in Year One = State ITC in Year One
+ State PTC in Year One
- State Income Taxes in Year One

State Tax Savings in Year n>1 = State PTC in Year n - State Income Taxes in Year n

Tax Effect on Equity -- Federal

The tax effect on equity cash flows are the tax calculations for federal income taxes. SAM makes the following federal income tax assumptions:

- For the Residential and Commercial financing options, federal taxable income includes any incentive payments that you specify as Federally taxable on the Incentives page, and the value of State Tax Savings.
- For the Commercial financing option, income tax paid on the value of energy is accounted for in the after-tax cash flow described below. For the Residential option, income tax is not paid on the value of energy.
- The federal tax rate is the value you specify on the Financing page.
- Investment-based incentives that appear in Year Zero of the cash flow are taxable in Year One.
- Project operating costs are tax deductible for both the Residential and Commercial financing options.
- Debt interest payments are deductible for the Residential option with a Mortgage type loan and for the Commercial option. Debt interest payments are not tax deductible for the Residential option with the Standard Loan type loan. You specify the residential loan type on the Financing page.

Depreciation (Commercial Only)

Depreciation applies only to the Commercial financing option, and depends on the depreciation schedule from the Depreciation page.

Federal Depreciation Schedule

For the Commercial financing option with a depreciation option defined on the Depreciation page, SAM displays the federal depreciation percentage in the Federal Depreciation Schedule row of the cash flow table. SAM determines the depreciation schedule (percentage and applicable years) based on the options you specify for state depreciation on the Depreciation page.

For the Residential financing option, depreciation does not apply, and SAM displays zeros in the cash flow.

Federal Depreciation

The depreciation amount is the product of the depreciation percentage determined by the depreciation schedule described above, and the total installed costs:

Depreciation in Year n = Depreciation Schedule (%) in Year n × (Total Installed Costs - Depreciation Basis Reduction)

Where *Depreciation Schedule* is described above, and the *Total Installed Costs* is from the System Costs page.

Basis Reduction depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked **Federal** boxes in the **Reduces Depreciation and ITC Bases** column, or an investment tax credit (ITC) on the Incentives page with checked **Federal** boxes in the **Reduces Depreciation Basis** column. For each IBI, CBI, or ITC with a check mark, SAM subtracts the total incentive amount and fifty percent of the tax credit amount from the total installed cost to calculate the depreciable base:

Depreciation Basis Reduction Year n = Total ITC × 0.5 + Total IBI + Total CBI + Total PBI

Where *ITC* includes all tax credits that you specified on the Incentives page to reduce the depreciation basis, and *IBI*, *CBI*, and *PBI* include all incentives you specified to reduce the depreciation basis.

For the Residential financing option, depreciation does not apply, and SAM displays zeros in the cash flow.

Federal Income Taxes

The federal income tax is the annual income tax owed before accounting for tax credits. A negative value indicates a net tax liability (tax owed), and a positive value indicates a net tax benefit (tax refund).

Federal Income Taxes: Residential with Standard Loan

For the Residential financing option with the Standard Loan loan type on the Financing page, debt interest payments are not tax-deductible:

Income Taxes in Year One = Federal Tax Rate
× (Total IBI in Year Zero
+ Total CBI in Year Zero
+ Total PBI in Year One
+ State Tax Savings in Year One
- Property Taxes in Year One)

Income Taxes in Year n>1 = Federal Tax Rate
× (Total PBI in Year n
+ State Tax Savings in Year n
- Property Tax in Year n)

Federal Income Taxes: Residential with Mortgage Loan

For the Residential financing option with the Mortgage loan type on the Financing page, debt interest payments are deducted:

Income Taxes in Year One = Federal Tax Rate
× (Total IBI in Year Zero
+ Total CBI in Year Zero
+ Total PBI in Year One
+ State Tax Savings in Year One
- Property Tax in Year One

- Debt Interest Payment in Year One)

Income Taxes in Year n>1 = Federal Tax Rate
× (Total PBI in Year n
+ State Tax Savings in Year n
- Property Tax in Year n
- Debt Interest Payment in Year n)

Federal Income Taxes: Commercial

For the Commercial financing option, SAM includes a depreciation deduction in the tax equation:

Income Taxes in Year One = Federal Tax Rate
× (Total IBI in Year Zero
+ Total CBI in Year Zero
+ Total PBI in Year One
+ State Tax Savings in Year One
- Operating Costs in Year One
- Debt Interest Payment in Year One
- Federal Depreciation in Year One)

Income Taxes in Year n>1 = Federal Tax Rate
× (Total PBI in Year n
+ State Tax Savings in Year n
- Operating Costs in Year n
- Debt Interest Payment in Year n
- Federal Depreciation in Year n)

Notes.

Because of the way it is defined, *Deductible Expenses* is negative when it represents a reduction in taxes, and so is added to the taxable income equation rather than subtracted.

For the Residential and Commercial financing options (except Commercial PPA), SAM assumes that electricity generated by the project displaces electricity that would have been purchased from the grid without the system. Therefore, SAM does not consider electricity sales for residential and commercial projects to be taxable income.

Federal Tax Savings

The federal tax savings is the net tax savings, accounting for income taxes and tax credits:

Federal Tax Savings in Year One = Federal ITC in Year One
+ Federal PTC in Year One
- Federal Income Taxes in Year One

Federal Tax Savings in Year n>1 = Federal PTC in Year n - Federal Income Taxes in Year n

After Tax Cost and Cash Flow

After Tax Cost

The after tax cost row represents the project's net annual costs for operating the system accounting for tax savings and incentive payments. It does not include the value of electricity generated by the system.

Note. SAM uses the present value of the after tax cost flow to calculate the levelized cost of energy for the residential and commercial financing options.

A positive after tax cost value represents a net inflow for the year, and a negative value represents a net outflow for the year.

Year Zero after tax cost are investment-related costs:

After Tax Cost in Year Zero = Loan Principal Amount
+ Total IBI in Year Zero
+ Total CBI in Year Zero
- Total Installed Cost

Where *Loan Principal Amount* is from the Financing page (equivalent to the Debt Balance in Year One of the cash flow), *Total IBI* and *Total CBI* are the values described above, and *Total Installed Cost* is from the System Costs page.

Year One is the first year that the project generates electricity. The after tax cost in Year One and subsequent years is:

After Tax Cost in Year n>0 = State Tax Savings
+ Federal Tax Savings
+ Total PBI
- Total Operating Expenses
- Total Debt Payment

Where *State Tax Savings*, *Federal Tax Savings*, *Total PBI*, *Operating Costs*, *Total Operating Expenses*, and *Debt Total Payment* are values described above.

After Tax Cash Flow

Note. The project after-tax NPV is the net present value of the after-tax cash flow.

The after tax cash flow represents the project's net cash flow including the value of energy generated by the system.

For the residential financing option, the value of energy is not taxable:

After Tax Cash Flow in Year n = After Tax Cost in Year n + Energy Value in Year n

For the commercial financing option, the after-tax cash flow is reduced by the state and federal income tax on the energy value. SAM assumes that without the renewable energy system, the commercial entity would have treated electricity purchases as a tax-deductible operating expense. With the system, the entity must pay tax on the portion of its income that it would have deducted:

After Tax Cash Flow in Year n = After Tax Cost in Year n + Energy Value in Year n × (1 - Effective Tax Rate)

Where *After Tax Cost* and *Energy Value* are described above.

The effective tax rate is a single number that includes both the federal income tax rate and state income tax rate:

Effective Tax Rate = Federal Tax Rate × (1 - State Tax Rate) + State Tax Rate

The federal and state tax rates are input variables on the Financing page.

20.2 IPP and Commercial PPA

This topic describes the cash flow table generated by the financial model for the Utility IPP and Commercial PPA financing options. See Financing Overview for details.

Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

SAM offers three options for exporting the cash flow table:

- **Copy to clipboard** copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.
- **Save as CSV** saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.
- **Send to Excel (Windows only)** creates a new Excel file that contains the data from the cash flow table in an Excel file, but no formulas.
- **Send to Excel with Equations (Windows only)** exports the cash flow data to an existing Excel workbook that contains formulas to illustrate how SAM's internal cash flow calculations work. The workbooks are in the *\exelib\spreadsheets\equations* folder of your SAM installation folder.

Notes.

SAM makes cash flow calculations internally during simulations. It does not use Excel to make the calculations. The two **Send to Excel** options are to help you analyze the cash flow data and understand how SAM's internal calculations work.

You can also display cash flow data by building a Table. This option allows you to choose the rows to include in the table, and also makes it possible to show cash flow results from a parametric analysis.

Cash Flow Year

The cash flow year is displayed in the top row of the cash flow table. In the descriptions below, the letter *n* indicates the cash flow year, where *n = 0* is Year Zero of the cash flow, *n = 1* is year one, *n = 2* is year two, etc.

Energy (kWh)

For systems that generate electricity, *Energy* is the total amount of electricity generated by the system in AC kilowatt-hours for each year.

For solar water heating systems, *Energy* is the amount of electricity saved by the solar water heating system in AC kilowatt-hours for each year.

The performance model runs hourly or sub-hourly simulations to calculate the total annual energy value, which the financial model considers to be energy value for in Year One of the cash flow. SAM adjusts that value using the factors you specify on the Performance Adjustment page to account for expected system downtime for maintenance, and degradation of system performance over time.

> **Note.** The annual energy value reported for Year one in the cash flow is not equal to the sum of the hourly energy values because the hourly values do not account for the **Percent of annual output** factor from the Performance Adjustment page.

For Year One, *Energy* is the value is calculated by the performance model:

Energy in Year One = Sum of Simulation Values x Percent of Annual Output

Where *Sum of Simulation Values* is the system's total annual electrical output (or energy saved) equal to the sum of the values calculated by the performance model (8,760 values for hourly simulations), and *Percent of Annual Output* is from the Performance Adjustment page.

> **Notes.**
>
> If you specify *Availability* on the Performance Adjustment page using the annual schedule option, SAM applies the value you specified for each year to the Year One Energy value:
> *Energy in Year n>1 = Energy in Year One × Availability in Year n*
>
> The Geothermal Power performance model runs simulations for each year of the analysis period rather than only for Year One. For the Geothermal Power model:
> *Energy in Year n = Energy in Year n × Availability in Year n*

For Years 2 and later:

Energy in Year n>1 = Energy in Year n-1 × (1 - Year-to-Year Decline in Output)

Where *Energy in Year n-1* is the previous year's energy value and *Year-to-Year Decline* is from the Performance Adjustment page.

> **Note.** If you specified **Year-to-year decline in output** on the Performance Adjustment page using the annual schedule option, SAM applies the value as follows (after applying the appropriate availability factor to calculate the Year One energy value):
>
> *Energy in Year n>1 = Energy in Year n × (1 - Year-to-Year Decline in Output in Year n)*

Energy Price ($/kWh)

The energy price in Year One is the PPA price:

Energy Price in Year One = Adjusted PPA Price

For analyses that do not involve time-dependent pricing, *Adjusted PPA Price* is equal to the PPA Price reported on the Metrics table.

For analyses that do involve time-dependent pricing, for each hour of the year, SAM multiplies the PPA price shown in the Metrics table (equivalent to the bid price) by the TOD factor for that hour to calculate a set of hourly energy prices for Year one. The *Adjusted PPA Price* is the average of the 8,760 hourly values.

Notes.

When you choose **Specify PPA Price** for **Solution Mode** on the Financing page, the PPA Price in the Metrics table is equal to the price you specify. When you choose **Specify IRR Target**, SAM calculates the PPA price required to meet the IRR target that you specify.

The TOD factors are on the Thermal Energy Storage page for CSP systems (parabolic trough, power tower, linear Fresnel, generic solar system), and on the Time of Delivery Factors page for photovoltaic and other systems.

To remove time-dependent pricing from your analysis, set the TOD factor for each of the 9 periods to one.

The energy price in years two and later is the first year price adjusted by the PPA escalation rate:

Energy Price in Year n>1 = Energy Price in Year n-1 × (1 + PPA Escalation Rate)^(n-1)

Note. SAM uses Energy Price to calculate the levelized cost of energy.

Energy Value ($)

The energy value is the a measure of the value of the electricity generated by the system.

Energy Value ($) = Energy (kWh) × Energy Price ($/kWh)

Where Energy and Energy Price are described above.

LCOE

The LCOE rows in the cash table show how SAM calculates the real and nominal levelized cost of energy (LCOE) values reported in the Metrics table.

NPV of Energy Value (nominal)

The present worth of the value in dollars of energy generated by the system in each year, representing total value of electricity generated by the system over the project analysis period:

NPV of Energy Value Nominal = Energy Value in Year 1 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^1
+ Energy Value in Year 2 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^2
+ Energy Value in Year 3 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^3
+ …
+ Energy Value in Year N ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^N

Where the analysis period *N* and *Nominal Discount Rate* are both on the Financing page.

NPV of Energy (nominal)

The present worth of the annual energy generated by the system, "discounted" at the nominal discount rate and representing the quantity in kWh of electricity generated by the system.

NPV of Energy Nominal = Energy in Year 1 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^1

+ Energy in Year 2 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^2
+ Energy in Year 3 ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^3
+ ...
+ Energy in Year N ÷ (1 + Nominal Discount Rate (%) ÷ 100%)^N

Where the analysis period *N* and *Nominal Discount Rate* are both on the Financing page.

LCOE Nominal

The nominal levelized cost of energy:

LCOE Nominal (cents/kWh) = NPV of Energy Value Nominal ($) ÷ NPV of Energy Nominal (kWh) * 100 (cents/$)

NPV of Energy (real)

The present worth of the annual energy generated by the system, "discounted" at the real discount rate and representing the quantity in kWh of electricity generated by the system.

NPV of Energy Real = Energy in Year 1 ÷ (1 + Real Discount Rate (%) ÷ 100%)^1
+ Energy in Year 2 ÷ (1 + Real Discount Rate (%) ÷ 100%)^2
+ Energy in Year 3 ÷ (1 + Real Discount Rate (%) ÷ 100%)^3
+ ...
+ Energy in Year N ÷ (1 + Real Discount Rate (%) ÷ 100%)^N

Where the analysis period *N* and *Real Discount Rate* are both on the Financing page.

LCOE Real

The real levelized cost of energy:

LCOE Real (cents/kWh) = NPV of Energy Value Nominal ($) ÷ NPV of Energy Real (kWh) * 100 (cents/$)

Operating Expenses

Recapitalization

The recapitalization cost applies only to geothermal projects and represents the cost required to drill new wells when the reservoir temperature drops below a certain level. The recapitalization cost is specified on the Geothermal System Costs page.

O&M (Operation and Maintenance) Costs

The annual operation and maintenance (O&M) costs are defined on the System Costs page and may be calculated as a fixed amount, a cost per system rated capacity, a cost per unit of energy output, or any combination of the three:

Fixed O&M Annual in Year n = Fixed Annual Cost ($/yr) × (1 + Inflation Rate + Escalation Rate) ^ n-1

*Fixed O&M in Year n = Fixed Cost by Capacity ($/kW-yr) × System Capacity * (1 + Inflation Rate + Escalation Rate)^(n-1)*

Variable O&M in Year n = Variable Cost by Generation ($/MWh) / 1000 (kWh/MWh) × Energy in Year n (kWh) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where Fixed Annual Cost, Fixed Cost by Capacity, Variable Cost by Generation, and Escalation Rate are from the System Costs page, and Inflation Rate is from the Financing page.

> **Note.** When you specify O&M costs using an annual schedule instead of a single value, SAM does not apply the inflation rate or escalation rate to the values you specify for each year.

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 23. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

Fuel

The following performance models include a fuel cost calculation:

- Parabolic trough (physical or empirical) with fossil backup
- Power tower with fossil backup
- Generic solar system with fossil backup
- Generic system for the primary fuel cost
- Biomass Power for biomass and supplementary coal feedstock costs

> **Note.** For the CSP systems listed above, SAM only considers the system to have a fossil-fired backup boiler when the fossil fill fraction variable on the Thermal Storage page is greater than zero.

For solar and generic systems listed above that consume a fuel, Fuel O&M is the annual fuel cost:

Fuel O&M in Year n = Annual Fuel Usage in Year One (kWh) × 0.003413 MMBtu per kWh × Fossil Fuel Cost ($/MMBtu) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Annual Fuel Usage in Year One* is the quantity of fuel consumed in Year One calculated by the performance model. *Fossil Fuel Cost* and *Escalation Rate* are from the System Costs page, and Inflation Rate is from the Financing page.

> **Note.** When you specify fuel costs using an annual schedule instead of a single value, SAM does not apply the inflation rate or escalation rate to the values you specify for each year.

For the biomass power model, SAM calculates feedstock and coal costs using feedstock usage and price values from the Feedstock Costs page:

Biomass Feedstock Costs in Year n = Total Biomass Fuel Usage in Year One (dry tons/year) × Biomass Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Coal Feedstock Costs in Year n = Total Coal Fuel Usage in Year One (dry tons/year) × Coal Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where the fuel usage and fuel costs are from the Feedstock Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

Insurance

The insurance cost applies in Year One and later of the cash flow:

Insurance in Year n = Total Installed Costs ($) × Insurance (%) × (1 + Inflation Rate)^(n-1)

Where *Total Installed Costs* is the value from the System Costs page, and Insurance and Inflation Rate are specified on the Financing page.

Property Assessed Value

The property assessed value is the value SAM uses as a basis to calculate the annual property tax payment:

Property Assessed Value in Year One = Assessed Value

Where *Assessed Value* is from the Financing page.

In Years 2 and later, the property assessed value is the Year One value adjusted by the assessed value decline value from the Financing page:

Property Assessed Value in Year n>1 = Assessed Value in Year One × [1 - Assessed Value Decline × (n-1)]

Where *Assessed Value Decline* is from the Financing page, expressed as a fraction instead of a percentage.

If the value of *1 - Assessed Value Decline* × *(n-1)* for a given year is equal to zero or less, then the *Property Assessed Value* in that year is zero.

Property Taxes

Property taxes apply in Year One and later of the cash flow:

Property Taxes in Year n = Property Assessed Value in Year n ($) × Property Tax (%)

Where *Property Assessed Value* is described above, and *Property Tax* is from the Financing page.

Net Salvage Value

SAM calculates the net salvage value using the percentage you specify on the Financing page and the total installed cost from the System Costs page. The salvage value applies in the final year of the project cash flow.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period

For residential projects, the salvage value has no effect on federal and state income tax because operating expenses are not taxable.

For commercial projects, because the salvage value reduces the operating expenses in the final year of the analysis period, it increases the federal and state income tax payment because operating expenses are deductible from federal and state income tax.

Total Operating Expenses

The total operating costs include operation and maintenance costs, and insurance and property tax payments:

Operating Costs = Fixed O&M Annual + Fixed O&M + Variable O&M + Fuel + Insurance + Property Taxes - Salvage Value

Operating Income

For utility projects, the operating income is the difference between revenues and operating costs:

Operating Income = Energy Value - Operating Costs

Financing

Debt Balance

The debt balance in Year One represents the debt portion of the investment costs, less incentives.

For residential and commercial:

Debt Balance in Year One = - (Total Installed Costs - Total IBI - Total CBI) × Debt Fraction

For commercial PPA and utility IPP:

Debt Balance in Year One = - (Total Installed Costs + Construction Financing Costs - Total IBI - Total CBI) × Debt Fraction

Where *Total Installed Costs* is from the System Costs page, *Total IBI* and *Total CBI* are the sums of all investment-based and capacity-based incentives specified on the Incentives page, and *Debt Fraction* is the value specified on the Financing page. *Construction Financing Costs* is from the Financing page.

In Years Two and later, the debt balance is calculated from the previous year's debt balance and debt repayment amounts:

Debt Balance in Year n>1 = Debt Balance in Year n-1 + Debt Repayment in Year n-1

Notes.

SAM shows the debt balance as a negative value to indicate net annual outflow. A value of zero indicates all debt is paid off.

The debt balance in Year One is different from the Principal Amount on the Financing page when your analysis includes either capacity-based or investment-based incentives.

Debt Interest Payment

The debt interest payment is the annual interest paid on debt:

Debt Interest Payment in Year n = - Debt Balance in Year n × Loan Rate

Where *Debt Balance* is described above, and *Loan Rate* is from the Financing page.

Debt Repayment

The debt repayment amount is the annual payment on principal amount assuming constant payments over the loan term. SAM calculates the amount using the levelized mortgage payment methodology equivalent to Excel's PPMT function:

Debt Repayment in Year n = -PPMT(Loan Rate,n,Loan Term,Principal Amount,0,0)

Where *Loan Rate*, *Loan Term*, and *Principal Amount* are from the Financing page.

Debt Total Payment

The total debt payment is the sum of interest and principal payments:

Debt Total Payment = Debt Interest Payment + Debt Repayment

Incentives

The incentive cash flow rows show the value of cash incentives and tax credits, which are used to calculate cash flows described above.

IBI (Investment Based Incentives)

Each IBI (federal, state, utility, other) applies in Year Zero of the project cash flow.

Because you can specify each IBI on the Incentives page as either an amount or a percentage, SAM calculates the value of each IBI as the sum of two values:

IBI as Amount = Amount

IBI as Percentage = Total Installed Cost ($) × Percentage (%), up to Maximum

IBI in Year 0 = IBI as Amount + IBI as Percentage

Where *Amount*, *Percentage* and *Maximum* are the values that you specify on the Incentives page, and *Total Installed Cost* is from the System Costs page.

Total IBI is the sum of the four IBI values (federal, state, utility, other).

Note. The IBI amount reduces the after tax cost flow in Year Zero, and the debt balance in Year One. This is because SAM assumes that debt payments begin in Year One, when the project is generating or saving electricity.

CBI (Capacity Based Incentives))

Each CBI (federal, state, utility, other) applies in Year Zero of the project cash flow:

CBI in Year 0 = System Capacity (W) × Amount ($/W), up to Maximum

Where System Capacity is the rated capacity of the system, and *Amount* and *Maximum* are the values you specify on the Incentives page.

Total CBI is the sum of the four CBI values (federal, state, utility, other).

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 24. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

PBI (Performance Based Incentive)

Each PBI (federal, state, utility, other) applies in Years One and later of the project cash flow, up to the number of years you specify:

PBI in Year n = Amount ($/kWh) × Energy in Year n (kWh) × (1 + Escalation)^(n-1), up to Term

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in Energy row of the cash flow table (described above).

Note. If you use an annual schedule to specify year-by-year PBI amounts, SAM ignores the escalation rate.

Total PBI is the sum of the four PBI amounts (federal, state, utility, other).

Important Note! If you specify a PBI amount on the Cash Incentives page, be sure to also specify the incentive term. If you specify a term of zero, the incentive will not appear in the cash flow table.

PTC (Production Tax Credit)

The state and federal PTC each apply in Year One and later of the project cash flow, up to the number of years you specify:

PTC in Year n = Amount ($/kWh) × (1 + Escalation)^(n-1) × Energy in Year n (kWh)

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in the Energy row of the cash flow table (described above).

SAM rounds the product *Amount ($/kWh) × (1 + Escalation)^(n-1)* to the nearest multiple of 0.1 cent as described in Notice 2010-37 of IRS Bulletin 2010-18.

Note. If you specify year-by-year PTC rates on the Incentives page using an Annual Schedule instead of a single value, SAM ignores the PTC escalation rate.

ITC (Investment Tax Credit)

The state and federal ITC each apply only in Year One of the project cash flow. For ITCs that you specify as a fixed amount:

ITC in Year One = Amount

Where *Amount* is the value you specify in the Incentives page.

For ITCs that you specify as a percentage of total installed costs:

ITC in Year One = (Total Installed Cost ($) - ITC Basis Reduction ($)) × Percentage (%), up to Maximum

Where *Total Installed Cost* is from the System Costs page, and *Percentage* and *Maximum* are the values you specify on the Incentives page.

ITC Basis Reduction applies only to the Commercial and Utility financing options, and depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked boxes under **Reduces Depreciation and ITC Bases**. For each IBI or CBI with a check mark, SAM subtracts the incentive amount from the total installed cost to calculate the ITC.

ITC Basis Reduction = IBI + CBI

Where *IBI* and *CBI* are the incentives that you have specified reduce the ITC basis on the Incentives page.

Tax Effect on Equity -- State

The tax effect on equity cash flows are the tax calculations for state income taxes. SAM makes the following state income tax assumptions:

- The state taxable income is the operating income in a given year.
- The state tax rate is the value you specify on the Financing page.

- Investment-based incentives that appear in Year Zero of the cash flow are taxable in Year One.
- Depreciation and debt interest payments are tax deductible items.

Depreciation

Depreciation depends on the depreciation schedule from the Depreciation page.

State Depreciation Schedule

SAM displays the state depreciation percentage in the State Depreciation Schedule row of the cash flow table based. SAM determines the depreciation schedule (percentage and applicable years) based on the options you specify for state depreciation on the Financing page.

State Depreciation

The depreciation amount is the product of the depreciation percentage determined by the depreciation schedule described above, and the depreciable base:

Depreciation in Year n = Depreciation Schedule (%) in Year n × (Total Installed Costs - Depreciation Basis Reduction)

Where *Depreciation Schedule* is described above, and the *Total Installed Costs* is from the System Costs page.

Basis Reduction depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked **State** boxes in the **Reduces Depreciation and ITC Bases** column, or an investment tax credit (ITC) with checked **State** boxes in the **Reduces Depreciation Basis** column. For each IBI, CBI, or ITC with a check mark, SAM subtracts the total incentive amount and fifty percent of the tax credit amount from the total installed cost to calculate the depreciable base:

Depreciation Basis Reduction Year n = ITC × 0.5 + IBI + CBI + PBI

Where *ITC* includes all tax credits that you specified on the Incentives page to reduce the depreciation basis, and *IBI*, *CBI*, and *PBI* include all incentives you specified to reduce the depreciation basis.

State Income Taxes

The state income tax is the annual income tax owed before accounting for tax credits. A negative value indicates a net tax liability (tax owed), and a positive value indicates a net tax benefit (tax refund).

Income Taxes in Year n = State Tax Rate
× (Operating Income in Year n
+ PBI in Year One
+ CBI in Year n
- State Depreciation in Year n
- Debt Interest Payment in Year n)

Where *PBI* and *CBI* is the sum of incentives that you have specified as being state taxable on the Incentives page, and *State Tax Rate* is from the Financing page.

Note. Because of the way it is defined, *Deductible Expenses* is negative when it represents a reduction in taxes, and so is an addition in the taxable income equation rather than a subtraction.

State Tax Savings

The net tax savings, accounting for income taxes and tax credits. A positive value indicates a net savings or cash inflow. A negative value indicates a net liability or cash outflow:

State Tax Savings in Year One = State PTC in Year One

+ State ITC in Year One
- State Income Taxes in Year One

State Tax Savings in Year n>1 = State PTC in Year n - State Income Taxes in Year n

Where *Income Taxes*, *Total PTC*, and *Total ITC* are described above.

Tax Effect on Equity -- Federal

The tax effect on equity cash flows are the tax calculations for federal income taxes. SAM makes the following federal income tax assumptions:

- The federal taxable income is the operating income in a given year.
- The federal tax rate is the value you specify on the Financing page.
- Investment-based incentives that appear in Year Zero of the cash flow are taxable in Year One.
- Depreciation and debt interest payments are tax deductible items.

Depreciation

Depreciation depends on the depreciation schedule from the Depreciation page.

Federal Depreciation Schedule

For the Commercial financing option with a depreciation option defined on the Depreciation page, SAM displays the federal depreciation percentage in the Federal Depreciation Schedule row of the cash flow table. SAM determines the depreciation schedule (percentage and applicable years) based on the options you specify for state depreciation on the Depreciation page.

Federal Depreciation

The depreciation amount is the product of the depreciation percentage determined by the depreciation schedule described above, and the total installed costs:

Depreciation in Year n = Depreciation Schedule (%) in Year n × (Total Installed Costs - Depreciation Basis Reduction)

Where *Depreciation Schedule* is described above, and the *Total Installed Costs* is from the System Costs page.

Basis Reduction depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked **Federal** boxes in the **Reduces Depreciation and ITC Bases** column, or an investment tax credit (ITC) with checked **Federal** boxes in the **Reduces Depreciation Basis** column. For each IBI, CBI, or ITC with a check mark, SAM subtracts the total incentive amount and fifty percent of the tax credit amount from the total installed cost to calculate the depreciable base:

Depreciation Basis Reduction Year n = Total ITC × 0.5 + Total IBI + Total CBI + Total PBI

Where *ITC* includes all tax credits that you specified on the Incentives page to reduce the depreciation basis, and *IBI*, *CBI*, and *PBI* include all incentives you specified to reduce the depreciation basis.

Federal Income Taxes

The federal income tax is the annual income tax owed before accounting for tax credits. A negative value indicates a net tax liability (tax owed), and a positive value indicates a net tax benefit (tax refund).

Income Taxes in Year n = Federal Tax Rate
× (Operating Income in Year n
+ PBI in Year One

+ CBI in Year n
- Federal Depreciation in Year n
- Debt Interest Payment in Year n)

Where *PBI* and *CBI* is the sum of incentives that you have specified as being state taxable on the Incentives page, and *Federal Tax Rate* is from the Financing page.

Note. Because of the way it is defined, *Deductible Expenses* is negative when it represents a reduction in taxes, and so is an addition in the taxable income equation rather than a subtraction.

Federal Tax Savings

The net tax savings, accounting for income taxes and tax credits. A positive value indicates a net savings or cash inflow. A negative value indicates a net liability or cash outflow:

Federal Tax Savings in Year One = Federal PTC in Year One
+ Federal ITC in Year One
- Federal Income Taxes in Year One

Federal Tax Savings in Year n>1 = Federal PTC in Year n - Federal Income Taxes in Year n

Where *Income Taxes*, *Total PTC*, and *Total ITC* are described above.

After Tax Cash Flow

The after tax cash flow represents the project's net cash flow including the value of energy generated by the system. A negative value represents a net outflow, and positive value represent a net inflow.

After Tax Cash Flow in Year Zero = - (1 - Debt Fraction)
× (Total Installed Cost
+ Total Construction Financing Cost
- Total IBI
- Total CBI)

Where *Debt Fraction* and *Total Construction Financing Cost* are the values from the Financing page, *Total Installed Cost* is from the System Costs page, and *Total IBI* and *Total CBI* amounts are the Year Zero incentive amounts from the cash flow table.

After Tax Cash Flow in Year n>0 = Operating Income
+ State Tax Savings
+ Federal Tax Savings
+ Total PBI
- Total Debt Payment

Where *Operating Income*, *State Tax Savings*, *Federal Tax Savings*, *Total PBI*, and *Total Debt Payment* are from the cash flow table and described above.

Pretax Debt Service Coverage Ratio

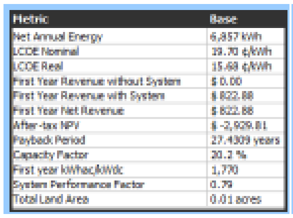
The debt-service coverage ratio is a measure of the cash available annually to meet debt principal and interest payments:

PreTax DSCR = Operating Income ÷ Debt Total Payment

The minimum DSCR value displayed in the Metrics table is the minimum value in the row of the cash flow table.

20.3 Single Owner

This topic describes the cash flow table generated by the financial model for the Utility Single Owner financing option. See Financing Overview for details.



Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

SAM offers three options for exporting the cash flow table:

- **Copy to clipboard** copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.
- **Save as CSV** saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.
- **Send to Excel (Windows only)** creates a new Excel file that contains the data from the cash flow table in an Excel file, but no formulas.
- **Send to Excel with Equations (Windows only)** exports the cash flow data to an existing Excel workbook that contains formulas to illustrate how SAM's internal cash flow calculations work. The workbooks are in the *\exelib\spreadsheets\equations* folder of your SAM installation folder.

Notes.

SAM makes cash flow calculations internally during simulations. It does not use Excel to make the calculations. The two **Send to Excel** options are to help you analyze the cash flow data and understand how SAM's internal calculations work.

You can also display cash flow data by building a Table. This option allows you to choose the rows to include in the table, and also makes it possible to show cash flow results from a parametric analysis.

Partial Income Statement: Project

The partial income statement rows show the annual revenue to the project as a whole. For projects with multiple partners, this revenue is the total revenue, before allocations to the different partners.

Net Energy (kWh)

For systems that generate electricity, *Energy* is the total amount of electricity generated by the system in AC kilowatt-hours for each year.

For solar water heating systems, *Energy* is the amount of electricity saved by the solar water heating system in AC kilowatt-hours for each year.

The performance model runs hourly or sub-hourly simulations to calculate the total annual energy value, which the financial model considers to be energy value for in Year One of the cash flow. SAM adjusts that value using the factors you specify on the Performance Adjustment page to account for expected system downtime for maintenance, and degradation of system performance over time.

> **Note.** The annual energy value reported for Year one in the cash flow is not equal to the sum of the hourly energy values because the hourly values do not account for the **Percent of annual output** factor from the Performance Adjustment page.

For Year One, *Energy* is the value is calculated by the performance model:

Energy in Year One = Sum of Simulation Values x Percent of Annual Output

Where *Sum of Simulation Values* is the system's total annual electrical output (or energy saved) equal to the sum of the values calculated by the performance model (8,760 values for hourly simulations), and *Percent of Annual Output* is from the Performance Adjustment page.

> **Notes.**
>
> If you specify *Availability* on the Performance Adjustment page using the annual schedule option, SAM applies the value you specified for each year to the Year One Energy value:
>
> *Energy in Year n>1 = Energy in Year One × Availability in Year n*
>
> The Geothermal Power performance model runs simulations for each year of the analysis period rather than only for Year One. For the Geothermal Power model:
>
> *Energy in Year n = Energy in Year n × Availability in Year n*

For Years 2 and later:

Energy in Year n>1 = Energy in Year n-1 × (1 - Year-to-Year Decline in Output)

Where *Energy in Year n-1* is the previous year's energy value and *Year-to-Year Decline* is from the Performance Adjustment page.

> **Note.** If you specified **Year-to-year decline in output** on the Performance Adjustment page using the annual schedule option, SAM applies the value as follows (after applying the appropriate availability factor to calculate the Year One energy value):
>
> *Energy in Year n>1 = Energy in Year n × (1 - Year-to-Year Decline in Output in Year n)*

PPA price (cents/kWh)

The PPA price in Year One is either the value you specify on the Financing page, or the value calculated by SAM to meet the IRR target you specify on the Financing page. The PPA price in Year One is the PPA price:

PPA Price in Year One = Adjusted PPA Price

For analyses that do not involve time-dependent pricing, *Adjusted PPA Price* is equal to the PPA Price reported on the Metrics table.

For analyses that do involve time-dependent pricing, for each hour of the year, SAM multiplies the PPA price shown in the Metrics table (equivalent to the bid price) by the TOD factor for that hour to calculate a set of hourly energy prices for Year one. The *Adjusted PPA Price* is the average of the 8,760 hourly values.

Notes.

When you choose **Specify PPA Price** for **Solution Mode** on the Financing page, the PPA Price in the Metrics table is equal to the price you specify. When you choose **Specify IRR Target**, SAM calculates the PPA price required to meet the IRR target that you specify.

The TOD factors are on the Thermal Energy Storage page for CSP systems (parabolic trough, power tower, linear Fresnel, generic solar system), and on the Time of Delivery Factors page for photovoltaic and other systems.

To remove time-dependent pricing from your analysis, set the TOD factor for each of the 9 periods to one.Where Adjusted PPA Price is either the value you specify on the Financing page, or a value calculated to cover project costs based on the target IRR you specify on the Financing page, adjusted by the time-of-delivery (TOD) factors.

In Years Two and later:

PPA Price in Year n>1 = PPA Price in Year n-1 × (1 + PPA Escalation Rate)^(n-1)

Where *PPA Escalation Rate* is from the Financing page.

Note. SAM uses the PPA Price to calculate the levelized cost of energy.

Total PPA revenue

The total PPA revenue is the project's annual revenue from electricity sales, not accounting for salvage value:

Total PPA Revenue = Net Energy (kWh) × PPA Price (cents/kWh) × 0.01 ($/cents)

Salvage value

SAM calculates the net salvage value using the percentage you specify on the Financing page and the total installed cost from the System Costs page. The salvage value applies in the final year of the project cash flow.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period

For residential projects, the salvage value has no effect on federal and state income tax because operating expenses are not taxable.

For commercial projects, because the salvage value reduces the operating expenses in the final year of the analysis period, it increases the federal and state income tax payment because operating expenses are deductible from federal and state income tax.

Total revenue

The projects annual revenue, accounting for salvage value.

Total Revenue = Total PPA Revenue + Salvage Value

Because Salvage Value is zero for all years except the last year of the analysis period, the Total Revenue and Total PPA Revenue are the same for all years except for the last year.

For the Single Owner and Leveraged Partnership Flip financing options (both of which include debt), total revenue may also include production-based incentive (PBI) amounts. For each PBI amount that you check on the Financing page under **Debt Service**, **Production Based Incentives (PBI) Available for Debt Service**, SAM displays a row for the PBI above the Total Revenue row, and includes the amount in the Total Revenue amount:

Total Revenue = Total PPA Revenue + Salvage Value + PBI

Expenses

The eight expense rows are for annual project costs calculated from assumptions you specify on the Financing and System Costs pages.

The four O&M expenses are based on the first year or annual schedule costs you specify under Operation and Maintenance Costs on the System Costs page, and are adjusted by the inflation rate from the Financing page and optional escalation rate from the System Costs page.

O&M Fixed expense

O&M Fixed Expense in Year n = Fixed Annual Cost ($) × (1 + Inflation Rate + Escalation Rate) ^ n-1

Where *Fixed Annual Cost* is from the System Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

O&M Capacity-based expense

O&M Capacity-based Expense in Year n = Fixed Cost by Capacity ($/kW-yr) × System Rated Capacity × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Fixed Cost by Capacity* is from the System Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 25. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field

CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

O&M Production-based expense

*O&M Production-based Expense in Year n = Variable Cost by Generation ($/MWh) × Net Energy in Year n (MWh) * (1 + Inflation Rate + Escalation Rate)^(n-1)*

Where *Variable Cost by Generation* is from the System Costs page, *Net Energy* is described above, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

O&M Fuel expense

The following performance models include a fuel cost calculation:

- Parabolic trough (physical or empirical) with fossil backup
- Power tower with fossil backup
- Generic solar system with fossil backup
- Generic system for the primary fuel cost
- Biomass Power for biomass and supplementary coal feedstock costs

Note. For the CSP systems listed above, SAM only considers the system to have a fossil-fired backup boiler when the fossil fill fraction variable on the Thermal Storage page is greater than zero.

For solar and generic systems listed above that consume a fuel, Fuel O&M is the annual fuel cost:

Fuel O&M in Year n = Annual Fuel Usage in Year One (kWh) × 0.003413 MMBtu per kWh × Fossil Fuel Cost ($/MMBtu) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Annual Fuel Usage in Year One* is the quantity of fuel consumed in Year One calculated by the performance model. *Fossil Fuel Cost* and *Escalation Rate* are from the System Costs page, and Inflation Rate is from the Financing page.

Note. When you specify fuel costs using an annual schedule instead of a single value, SAM does not apply the inflation rate or escalation rate to the values you specify for each year.

For the biomass power model, SAM calculates feedstock and coal costs using feedstock usage and price values from the Feedstock Costs page:

Biomass Feedstock Costs in Year n = Total Biomass Fuel Usage in Year One (dry tons/year) × Biomass Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Coal Feedstock Costs in Year n = Total Coal Fuel Usage in Year One (dry tons/year) × Coal Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where the fuel usage and fuel costs are from the Feedstock Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

Insurance expense

The insurance cost applies in Year One and later of the cash flow:

Insurance in Year n = Total Installed Costs ($) × Insurance (%) × (1 + Inflation Rate)^(n-1)

Where *Total Installed Costs* is the value from the System Costs page, and Insurance and Inflation Rate are specified on the Financing page.

Property tax net assessed value

The property assessed value is the value SAM uses as a basis to calculate the annual property tax payment:

Property Assessed Value in Year One = Assessed Value

Where *Assessed Value* is from the Financing page.

In Years 2 and later, the property assessed value is the Year One value adjusted by the assessed value decline value from the Financing page:

Property Assessed Value in Year n>1 = Assessed Value in Year One × [1 - Assessed Value Decline × (n-1)]

Where *Assessed Value Decline* is from the Financing page, expressed as a fraction instead of a percentage.

If the value of *1 - Assessed Value Decline* × *(n-1)* for a given year is equal to zero or less, then the *Property Assessed Value* in that year is zero.

Property tax expense

Property taxes apply in Year One and later of the cash flow:

Property Taxes in Year n = Property Assessed Value in Year n ($) × Property Tax (%)

Where *Property Assessed Value* is described above, and *Property Tax* is from the Financing page.

Annual Developer (Lessee LLC) Margin (Sale Leaseback only)

Annual Developer Margin in Year n = Developer Operating Margin × (1 + Developer Margin Escalation)^(n-1)

Where *Developer Operating Margin* and *Developer Margin Escalation* are from the Financing page.

Total operating expense

The total operating expense is the sum of expenses:

Total Operating Expense in Year n = O&M Fixed Expense + O&M Capacity-based Expense + O&M Production-based Expense + O&M Fuel Expense + Insurance Expense + Property Tax Expense

EBITDA ($)

Earnings before interest, taxes, depreciation and amortization:

EBITDA = Total Revenue - Total Operating Expense

Where *Total Revenue* and *Total Operating Expense* are described above.

Cash Flow: Project

The project cash flows include those from operating activities, investing activities, incentives, and issuance of equity. The pre-tax cash flow is the total project cash flow.

Project Cash Flows from Operating Activities

The cash flow from operating activities are the project earnings including interest on reserves and production-based incentives payments less interest paid on debt.

EBITDA

The earnings before interest, taxes, depreciation and amortization described above.

Interest on reserves

Interest on Reserves = Total Reserves ($) × Interest on Reserves (%)

Where *Total Reserves* is the sum of *Major Equipment Reserves*, *Working Capital Reserve*, and *Debt Service Reserves*, and *Interest on Reserves* is from the Financing page.

PBI (Federal, State, Utility, Other, Total)

These values represent income from production-based incentive payments, calculated as described below under Incentives.

Total project cash flow from operating activities

Total = EBITDA + Interest on Reserves + Total PBI - Interest

Project Cash Flows from Investing Activities

Purchase of property cost

The purchase of property cost applies only in Year Zero of the cash flow.

Purchase of Property Cost = Total Installed Cost + Debt Service Reserve + Working Capital Reserve

Where *Total Installed Cost* is from the System Costs page, and *Debt Service Reserve* and *Working Capital Reserve* are the total reserve amounts described below.

(Increase)/Decrease in working capital reserve account

The working capital reserve amount in Year Zero depends on the Months of Operating Costs from the Financing page and the Year One total operating expense:

Capital Reserve in Year Zero = Total Operating Expense in Year One ($) × Months of Operating Costs (months) ÷ 12 (months)

In Year One and later:

Capital Reserve in Year n>0 = Capital Reserve in Year n-1 ($) - Total Operating Expense in Year n ($) × Months of Operating Costs (months) ÷ 12 (months)

Where *Months of Operating Costs* is from the Financing page.

(Increase)/Decrease in major equipment reserve accounts

For each of the up to three major equipment reserve accounts that you specify on the Financing page, SAM calculates the annual amount required to ensure that sufficient funds are available in the replacement year to cover the replacement cost:

For example, in the example described below under Major Equipment Capital Spending, the annual increase in reserves is \$530,682/year = \$2,653,400 ÷ 5 years.

Increase in Major Equipment Reserve = Inflation Adjusted Replacement Cost in Replacement Year (\$) ÷ Replacement Year (year)

The increase is shown in the cash flow as a negative value.

In the year that the replacement occurs (in this example, Year 5), the decrease in major equipment reserve account is \$2,122,727 = \$2,653,400 - \$430,682.

Decrease in Major Equipment Reserve in Replacement Year = Inflation Adjusted Replacement Cost in Replacement Year - Increase in Major Equipment Reserve

The decrease is shown in the cash flow as a positive value.

Major equipment capital spending

For each of the up to three major equipment reserve accounts that you specify on the Financing page, the inflation-adjusted amount is reported in the year that you specify.

For example, if you specify a \$2,500 (in Year One dollars) replacement cost with a 5 year replacement frequency, and an inflation rate of 1.5% on the Financing page, SAM reports a major equipment capital spending amounts in years 5, 10, 15 etc. For Year 5, the amount would be \$2,653,400 = \$2,500,000 × (1 + 0.015)^4.

In each year that the replacement occurs:

Capital Spending = - Replacement Cost (Year One \$) × (1 + Inflation Rate)^(Replacement Year - 1)

The value is negative because it represents an expense or outflow.

Total project cash flow from investing activities

The total cash flow from investing activities is the sum of purchase property cost, reserve account deposits or withdrawals, and capital spending:

Total in Year Zero = Purchase of Property Cost + Major Equipment Reserve Account

Total in Year n>0 = Major Equipment Reserve Account + Major Equipment Capital Spending

Project Cash Flows from Financing Activities

Cash flows from financing activities include income from incentive payments, equity capital, and, for Single Owner and Leveraged Partnership Flip, debt capital.

Total IBI

The total investment-based incentive amount, described below.

Total CBI

The total capital-based incentive amount, described below.

Equity Capital

The equity capital invested in the project.

Issuance of Equity in Year Zero = Total Installed Cost + Financing Cost - (Debt Funding + Total IBI + Total CBI)

Where *Total Installed Cost* is the project capital cost from the System Costs page, *Financing Cost* is from the Metrics table, *Debt* (Single Owner and Leveraged Partnership Flip only) is the debt funding amount described below, and *Total IBI* and *Total CBI* are the investment-based incentive and capacity based incentive amounts described below.

Total project cash flow from financing activities

The total cash flow from financing activities is the sum of equity capital, incentive payments, and debt capital.

Total in Year Zero = Issuance of Equity + Total IBI + Total CBI + Debt Funding

Total in Year n>0 = Debt Repayment

Project total pre-tax cash flow

The pre-tax cash flow is the cash flow and accounts for operating expenses, investment earnings, and incentive payments.

Total Project Pre-tax Cash Flow in Year Zero = Issuance of Equity

Where *Issuance of Equity* is the equity investment in the project described above.

Total Project Pre-tax Cash Flow in Year n>0 = Total Cash Flows from Operating Activities + Total Cash Flows from Investing Activities + Total Incentives

Total Project Returns

The total project returns rows of the cash flow table show pre- and after-tax cash flows and returns from the project perspective. Returns from each partner's perspective appear under the Partners Returns heading and are described below.

Project pre-tax returns

Total project pre-tax returns

The total annual pre-tax cash flow is the cash flow and accounts for operating expenses, investment earnings, and incentive payments.

Pre-tax Cash Flow in Year Zero = Issuance of Equity

Where *Issuance of Equity* is the equity investment in the project described above.

Pre-tax Cash Flow in Year n>0 = Total Cash Flows from Operating Activities + Total Cash Flows from Investing Activities + Total Incentives

Project pre-tax cumulative IRR

SAM calculates the cumulative IRR for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the pre-tax cash flow described above.

Project pre-tax cumulative NPV

The cumulative net present value in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the pre-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Project after-tax returns

Cash

The pre-tax cash flow, described above.

Total project after-tax returns

The total annual after-tax cash flow is the sum of the pre-tax cash flow and tax credits less income tax payments:

After-tax Cash Flow in Year Zero = Pre-tax Cash Flow in Year Zero

After-tax Cash Flow in Year One = Pre-tax Cash Flow in Year One + Total ITC + Total PTC + Project Tax Benefit

After-tax Cash Flow in Year n>1 = Pre-tax Cash Flow in Year n + Total PTC + Project Tax Benefit

Project after-tax cumulative IRR

SAM calculates the cumulative IRR for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+IRR)^n} = 0$$

Where $C_{AfterTax,n}$ is the after-tax cash flow described above.

Project after-tax cumulative NPV

The cumulative net present value in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+d_{nominal})^n}$$

Where $C_{AfterTax,n}$ is the after-tax cash flow described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

Project LCOE

SAM reports quantities used in the LCOE calculation in the cash flow table for reference. For a description of the LCOE see Levelized Cost of Energy (LCOE).

Project PPA revenue

The total PPA revenue is the project's annual revenue from electricity sales, not accounting for salvage value:

Project PPA Revenue = Net Energy (kWh) × PPA Price (cents/kWh) ÷ 100 (cents/$)

Net Energy (kWh)

The total amount of electricity generated by the system in AC kilowatt-hours for each year. See description above

NPV of PPA revenue

The present value of the annual PPA revenue streams over the analysis period used as the numerator of the LCOE equation:

$$\mathrm{NPV(Revenue)} = \sum_{n=0}^{N} \frac{R_{PPA,n}}{(1+d_{nominal})^n}$$

Where $R_{PPA,n}$ is the revenue from electricity sales-tax cash flow described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

NPV of net annual energy (nominal)

The LCOE calculation requires a discounted energy term in the denominator. The value discounted using the nominal discount rate is for the nominal LCOE equation.

$$\mathrm{NPV(Energy\ Nominal)} = \sum_{n=0}^{N} \frac{Q_n}{(1+d_{nominal})^n}$$

Where Q_n is the annual energy value described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

Project Nominal LCOE

Project Nominal LCOE = NPV(Revenue) / NPV(Energy Nominal)

NPV of net annual energy (real)

The LCOE calculation requires a discounted energy term in the denominator. The value discounted using the real discount rate is for the real LCOE equation.

$$\mathrm{NPV(Energy\ Real)} = \sum_{n=0}^{N} \frac{Q_n}{(1+d_{real})^n}$$

Where Q_n is the annual energy value described above, and d_{real} is the nominal discount rate from the Financing page.

Project Real LCOE

Project Real LCOE = NPV(Revenue) / NPV(Energy Real)

Incentives

Incentives may consist of either cash incentives (IBI, CBI, PBI) or tax credits (ITC, PTC), and may either calculated based on project investment costs (IBI, CBI, ITC), or the project's energy production (PBI, PTC).

The values in the incentives rows of the cash flow table are shown for reference. Their impact on project cash flows are shown in the project cash flows described above:

- PBI income appears under **Cash Flows from Operating Activities**.
- IBI and CBI income appear under **Cash Flows from Investing Activities**.
- ITC and PTC amounts appear under after-tax project returns.

The incentive cash flow rows show the value of cash incentives and tax credits, which are used to calculate cash flows described above.

IBI (Investment Based Incentives)

Each IBI (federal, state, utility, other) applies in Year Zero of the project cash flow.

Because you can specify each IBI on the Incentives page as either an amount or a percentage, SAM calculates the value of each IBI as the sum of two values:

IBI as Amount = Amount

IBI as Percentage = Total Installed Cost ($) × Percentage (%), up to Maximum

IBI in Year 0 = IBI as Amount + IBI as Percentage

Where *Amount*, *Percentage* and *Maximum* are the values that you specify on the Incentives page, and *Total Installed Cost* is from the System Costs page.

Total IBI is the sum of the four IBI values (federal, state, utility, other).

Note. The IBI amount reduces the after tax cost flow in Year Zero, and the debt balance in Year One. This is because SAM assumes that debt payments begin in Year One, when the project is generating or saving electricity.

CBI (Capacity Based Incentives))

Each CBI (federal, state, utility, other) applies in Year Zero of the project cash flow:

CBI in Year 0 = System Capacity (W) × Amount ($/W), up to Maximum

Where System Capacity is the rated capacity of the system, and *Amount* and *Maximum* are the values you specify on the Incentives page.

Total CBI is the sum of the four CBI values (federal, state, utility, other).

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 26. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle

Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

PBI (Performance Based Incentive)

Each PBI (federal, state, utility, other) applies in Years One and later of the project cash flow, up to the number of years you specify:

PBI in Year n = Amount ($/kWh) × Energy in Year n (kWh) × (1 + Escalation)^(n-1), up to Term

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in Energy row of the cash flow table (described above).

Note. If you use an annual schedule to specify year-by-year PBI amounts, SAM ignores the escalation rate.

Total PBI is the sum of the four PBI amounts (federal, state, utility, other).

Important Note! If you specify a PBI amount on the Cash Incentives page, be sure to also specify the incentive term. If you specify a term of zero, the incentive will not appear in the cash flow table.

PTC (Production Tax Credit)

The state and federal PTC each apply in Year One and later of the project cash flow, up to the number of years you specify:

PTC in Year n = Amount ($/kWh) × (1 + Escalation)^(n-1) × Energy in Year n (kWh)

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in the Energy row of the cash flow table (described above).

SAM rounds the product *Amount ($/kWh) × (1 + Escalation)^(n-1)* to the nearest multiple of 0.1 cent as described in Notice 2010-37 of IRS Bulletin 2010-18.

Note. If you specify year-by-year PTC rates on the Incentives page using an Annual Schedule instead of a single value, SAM ignores the PTC escalation rate.

ITC (Investment Tax Credit)

The state and federal ITC each apply only in Year One of the project cash flow. For ITCs that you specify as a fixed amount:

ITC in Year One = Amount

Where *Amount* is the value you specify in the Incentives page.

For ITCs that you specify as a percentage of total installed costs:

ITC in Year One = (Total Installed Cost ($) - ITC Basis Reduction ($)) × Percentage (%), up to Maximum

Where *Total Installed Cost* is from the System Costs page, and *Percentage* and *Maximum* are the values you specify on the Incentives page.

ITC Basis Reduction applies only to the Commercial and Utility financing options, and depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked boxes under **Reduces Depreciation and ITC Bases**. For each IBI or CBI with a check mark, SAM subtracts the incentive amount from the total installed cost to calculate the ITC.

ITC Basis Reduction = IBI + CBI

Where *IBI* and *CBI* are the incentives that you have specified reduce the ITC basis on the Incentives page.

Debt

The debt amounts depend on the following inputs from the Financing page:

- Debt Rate
- DSCR

Funding

The funding amount applies in Year Zero, and is the size of debt assuming the constant DSCR specified on the Financing page:

$$\text{Funding} = \sum_{n=1}^{N} \frac{\frac{CAFDS_n}{(1 + Debt\ Rate)^n}}{DSCR}$$

Where $CAFDS_n$ is the cash available for debt service in Year n, and *Debt Rate* and *DSCR* are from the Financing page.

CAFDS in Year n= EBIDTA in Year n - Sum of Major Equipment Replacement Reserves in Year n

Where EBIDTA and Major Equipment Reserves are described above and below, respectively.

Repayment

Repayment applies in Year One and later, and represents annual debt payments.

Repayment in Year n = - Principal in Year n

Where *Principal in Year n* is described below.

Ending Balance

The ending balance applies in Year Zero and later:

Ending Balance in Year Zero = Funding

Where *Funding* is described above.

Ending Balance in Year n = Ending Balance in Year n-1 + Repayment in Year n

Where *Repayment* is described above.

Principal

The principal applies in Year One and later:

Principal in Year n = Total P&I in Year n - Interest in Year n

Where *Total P&I* and *Interest* are described below.

Interest

The interest applies in Year One and later:

Interest in Year n = Ending Balance in Year n × Debt Rate

Where *Ending Balance* is described above, and *Debt Rate* is from the Financing page.

Total P&I

The total principal and interest applies in Year One and later:

Total P&I in Year n = CAFDS in Year n ÷ DSCR

Where *CAFDS in Year n* is described above (under Funding), and *DSCR* is from the Financing page.

Reserve Accounts

Reserve accounts include debt service, working capital reserve, and major equipment replacement reserves. The reserve account amounts depend on the following inputs from the Financing page:

- Inflation Rate
- Debt Service Reserve Account (months P&I)
- Working Capital Reserve Months of Operating Costs
- Major Equipment Replacement Reserve Account [1-3] Frequency (years)
- Major Equipment Replacement [1-3] (Year 1 $)

Lease Payment Reserve (Sale Leaseback only)

Lease Payment Reserve = Tax Investor (Lessor) Required Lease Payment Reserve (months) ÷ 12 × Total Developer Pre-tax Cash Flow from Operating Activities in Year n+1

Debt Service Reserve

The debt service reserve applies in Year Zero and later:

Debt Service Reserve = Debt Service Reserve Account (months P&I) ÷ 12 × Total P&I in Year n+1

Where *Debt Service Reserve Account (months P&I)* is from the Financing page, and *Total P&I in Year n+1* is described under Debt above.

Working Capital Reserve

Working capital reserve applies in Year Zero and later:

Working Capital Reserve = Months of Operating Costs × Operating Expenses in Year n+1

Where *Months of Operating Costs* is from the Financing page, and *Operating Expenses in Year n+1* is described above.

Major Equipment Replacement Reserves

You can specify up to three major equipment reserve accounts on the Financing page. For each account, the amount applies in Year One and later of the cash flow:

Major Equipment Reserve in Year n = Major Equipment Reserve in Year n-1 + Funding + Release of Funds

Where Major Equipment Reserve in Year Zero = 0, and:

Funding = Release of Funds in Year of Next Replacement ÷ Replacement Frequency

Release of Funds in Year of Next Replacement = - Replacement Cost in Year One $ × (1 + Inflation Rate)^(n-1)

Where *Replacement Frequency*, *Replacement Cost in Year One $*, and *Inflation Rate* are from the Financing page

Depreciation and ITC (State and Federal)

The federal and state Depreciation and ITC tables show the depreciable basis calculation for each of the up to seven depreciation classes for federal and state tax purposes:

- The total depreciable amount includes the total installed cost, development fee, equity closing cost, debt service reserve, working capital reserve, and for the Sale Leaseback financing option, the lease payment reserve.
- The depreciation class allocations on the Financing page determine how the depreciable basis is allocated to the different depreciation classes (MACRS 5-yr, Straight Line, etc.).
- For each state and federal IBI and CBI with **Reduces Depreciation and ITC Bases** checked on the Incentives page, the full incentive amount reduces the depreciable basis.
- For each state and federal ITC with **Reduces Depreciation Basis** checked on the Incentives page, 50% of the tax credit amount reduces the depreciable basis.
- For each depreciation class with a checked box under **Bonus Depreciation** on the Financing page, the depreciable basis is the product of the bonus depreciation percentage and the adjusted depreciable basis. (The adjusted depreciable basis is the total depreciable after incentives and tax credit adjustments.)
- For state and federal taxes, depreciation for major equipment replacement reserves uses the class specified on the Financing page.

The depreciation amounts depend on the total installed cost from the System Costs page, and the following inputs from other pages.

From the Financing page:

- Development Fee
- Debt Closing Costs
- Debt Closing Fee
- Equity Closing Cost
- Construction Financing
- Other Financing Cost

From the Incentives page:

- State ITC as Percentage
- State ITC Maximum
- State ITC as Amount
- Federal ITC as Percentage
- Federal ITC Maximum
- Federal ITC as Amount
- Status of **Reduces Depreciation Basis** check boxes
- The amounts and percentages of any incentive with **Reduces Depreciation and ITC Bases** checked

From the Depreciation page:

- Allocations for each depreciation class
- Bonus depreciation amounts and applicable depreciation classes
- ITC qualification status of depreciation classes

The depreciation amounts also depend on the following cash flow values:

- Debt service reserve
- Working capital reserve
- IBI (only for incentives shown to reduce depreciation basis on Incentives page)
- CBI (only for incentives shown to reduce depreciation basis on Incentives page)
- Debt funding
- For state depreciation, the federal ITC basis disallowance amounts for each depreciation class
- For federal depreciation, the state ITC basis disallowance amounts for each depreciation class

Gross Depreciable Basis with IBI and CBI Reductions Before ITC Reductions

For each depreciable class, the depreciable basis before reduction by the ITC is the gross depreciable basis less IBI and CBI amounts for incentives on the Cash Incentives page with **Reduces Depreciation and ITC Bases** checked.

> **Note.** The IBI and CBI reduce the depreciation basis for state taxes only when **State** under **Reduces Depreciation and ITC Bases** is checked. Similarly, the IBI and CBI reduce the depreciation basis for federal taxes only when **Federal** under **Reduces Depreciation and ITC Bases**.

% of Total Depreciable Basis

The normalized allocation for each depreciation class allocation:

% of Total Depreciable Basis = Allocation ÷ Sum of Allocations

Where *Allocation* is the percentage for the given depreciable class, and *Sum of Allocations* is the sum of all allocations from the Financing page.

Gross Amount Allocated

The gross depreciable basis before reductions for each depreciation class:

Gross Amount Allocated = % of Total Depreciable Basis × Total Depreciable Amount

Where % of Total Depreciable Basis is described above, and

Total Depreciable Amount = Total Installed Cost + Development Fee + Equity Closing Cost + Debt Closing Costs + Debt Closing Fee × Funding + Debt Service Reserve + Working Capital Reserve + Lease Payment Reserve

Where *Total Installed Cost* is from the System Costs page; *Development Fee*, *Equity Closing Cost*, *Debt Closing Costs*, and *Debt Closing Fee* are from the Financing page; and *Debt Service Reserve*, *Working Capital Reserve* and *Lease Payment Reserve* (Sale Leaseback financing option only) are other values in the cash flow described above

Reduction: IBI

The reduction in depreciation basis from IBI payments:

Reduction IBI = Total IBI that Reduce Depreciation × % of Total Depreciable Basis

Where *Total IBI that Reduce Depreciation* is the sum of IBI values in the cash flow for incentives with **Reduces Depreciation and ITC Bases** checked on the Incentives page. For the state depreciation table, **State** must be checked for the incentive to reduce the state depreciation basis. For the federal depreciation table, **Federal** must be checked. *% of Total Depreciable Basis* is the allocation for the depreciation class described above.

Reduction: CBI

The reduction in depreciation basis from CBI payments:

Reduction CBI = Total CBI that Reduce Depreciation × *% of Total Depreciable Basis*

Where *Total CBI that Reduce Depreciation* is the sum of CBI values in the cash flow for incentives with **Reduces Depreciation and ITC Bases** checked on the Incentives page. For the state depreciation table, **State** must be checked for the incentive to reduce the state depreciation basis. For the federal depreciation table, **Federal** must be checked. *% of Total Depreciable Basis* is the allocation for the depreciation class described above.

Depreciable Basis Prior to ITC

The depreciable basis reduced by CBI and IBI amounts:

Depreciable Basis Prior to ITC = Gross Amount Allocated - Reduction: IBI - Reduction: CBI

ITC Reduction

For each ITC on the Incentives page with **Reduces Depreciation Basis** checked, 50% of the ITC amount can be included in the depreciable basis for each depreciable class with **ITC Qualification** checked on the Depreciation page. SAM calculates the ITC reduction amount for ITCs that you specify on the Incentives page a percentage of the total installed costs with a maximum amount, and ITCs that you specify as a fixed amount.

Note. The ITC reduces the depreciation basis for state taxes only when **State** under **Reduces Depreciation Basis** is checked on the Incentives page, and when **State** is checked under **ITC Qualification** for the depreciation class on the Depreciation page. Similarly, the ITC reduces the depreciation basis for federal taxes only when **Federal** is checked under **Reduces Depreciation Basis** and under **ITC Qualification** for the depreciation class.

For each ITC specified as a percentage and maximum on the Incentives page, the *ITC Basis Disallowance* is the amount that may be available for depreciation basis reduction. (The ITC Reduction amounts are the amounts actually available.):

ITC Qualifying Costs

For depreciation classes with **ITC Qualification** checked on the Depreciation page:

ITC Qualifying Costs = Depreciable Basis Prior to ITC

% of ITC Qualifying Costs

For each depreciable class:

% of ITC Qualifying Costs = ITC Qualifying Costs ÷ *Total Depreciable Basis Prior to ITC*

Where *Total Depreciable Basis Prior* to ITC is the sum of *Depreciable Basis Prior to ITC* for all depreciable classes.

ITC Amount

ITC Amount = % of ITC Qualifying Costs × *ITC Qualifying Costs*

ITC Basis Disallowance

The ITC depreciation basis disallowance is 50% of the ITC amount:

ITC Basis Disallowance = ITC Amount × *0.5*

For each ITC specified as a fixed amount on the Incentives page, the ITC Basis Disallowance is the amount that may be available for depreciation basis reduction. (The ITC Reduction amounts are the amounts actually available.):

ITC Amount

For each depreciable class, the Total ITC Amount is the amount that may be available for depreciation reduction:

ITC Amount = Total ITC Amount × % of ITC Qualifying Costs

Where, for the state depreciation table, *Total ITC Amount* is the state ITC amount from the Incentives page. For the federal depreciation table, *Total ITC Amount* is the federal ITC amount from the Incentives page.

ITC Basis Disallowance

The ITC depreciation basis disallowance is 50% of the ITC amount:

ITC Basis Disallowance = ITC Amount × 0.5

The depreciable basis after ITC reduction is the sum of the total ITC basis disallowance values for the ITCs with **Reduces Depreciation Basis** checked on the Incentives pages.

ITC Reduction: State

ITC Reduction: State = ITC Basis Disallowance (ITC as %) + ITC Basis Disallowance (ITC as Fixed Amount)

Where the ITC basis disallowance values are from the state depreciation table for the ITCs that reduce depreciation basis.

ITC Reduction: Federal

ITC Reduction: Federal = ITC Basis Disallowance (ITC as %) + ITC Basis Disallowance (ITC as Fixed Amount)

Where the ITC basis disallowance values are from the federal depreciation table for the ITCs that reduce depreciation basis.

Depreciable Basis after ITC Reduction

Depreciable Basis after ITC Reduction = Depreciable Basis Prior to ITC - ITC Reduction:State - ITC Reduction:Federal

Bonus Depreciation

For each depreciation class that qualifies for bonus depreciation as indicated by the check boxes under Bonus Depreciation on the Depreciation page, bonus depreciation percentage applies to the depreciable basis.

> **Note.** The bonus depreciation percentage applies to the depreciation basis for state taxes only when **State** under **Bonus Depreciation** is checked. Similarly, the bonus depreciation percentage applies for federal taxes only when **Federal** under **Reduces Depreciation Basis** is checked.

First Year Bonus Depreciation

For each depreciation class with **Bonus Depreciation** checked on the Depreciation page:

First Year Bonus Depreciation = Depreciable Basis after ITC Reduction × Bonus Depreciation Percentage

Where Bonus Depreciation Percentage is from the Depreciation page: The state bonus percentage applies to the state depreciation table, and the federal percentage applies to the federal depreciation table.

Depreciable Basis

The depreciable basis after IBI, CBI, ITC and bonus depreciation reduction is the basis to which the depreciation percentages defined by the depreciation class apply.

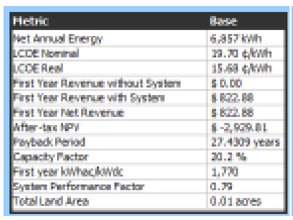
Depreciable Basis after Bonus Reduction = Depreciable Basis after ITC Reduction - First Year Bonus Depreciation

The following table shows the depreciation percentage by year for each depreciation class. For each depreciation class, the percentage is applied to the depreciable basis amount for the given year in the cash flow:

Years 1-10	1	2	3	4	5	6	7	8	9	10
5-yr MACRS	20.0	32.0	19.2	11.5	11.5	5.8				
15-yr MACRS	5.0	9.5	8.6	7.7	6.9	6.2	5.9	5.9	5.9	5.9
5-yr SL	10.0	20.0	20.0	20.0	20.0	10.0				
15-yr SL	3.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
20-yr SL	2.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	1.3	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 11-20	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
15-yr MACRS	5.9	5.9	5.9	5.9	5.9	3.0				
15-yr SL	6.7	6.7	6.7	6.7	6.7	3.3				
20-yr SL	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 21-30	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
20-yr SL	2.5									
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 31-40	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	1.3

20.4 All Equity Partnership Flip

This topic describes the cash flow table generated by the financial model for the Utility All Equity Partnership Flip financing option. See Financing Overview for details.



Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

SAM offers three options for exporting the cash flow table:

- **Copy to clipboard** copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.

- **Save as CSV** saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.
- **Send to Excel (Windows only)** creates a new Excel file that contains the data from the cash flow table in an Excel file, but no formulas.
- **Send to Excel with Equations (Windows only)** exports the cash flow data to an existing Excel workbook that contains formulas to illustrate how SAM's internal cash flow calculations work. The workbooks are in the *\exelib\spreadsheets\equations* folder of your SAM installation folder.

Notes.

SAM makes cash flow calculations internally during simulations. It does not use Excel to make the calculations. The two **Send to Excel** options are to help you analyze the cash flow data and understand how SAM's internal calculations work.

You can also display cash flow data by building a Table. This option allows you to choose the rows to include in the table, and also makes it possible to show cash flow results from a parametric analysis.

Partial Income Statement: Project

The partial income statement rows show the annual revenue to the project as a whole. For projects with multiple partners, this revenue is the total revenue, before allocations to the different partners.

Net Energy (kWh)

For systems that generate electricity, *Energy* is the total amount of electricity generated by the system in AC kilowatt-hours for each year.

For solar water heating systems, *Energy* is the amount of electricity saved by the solar water heating system in AC kilowatt-hours for each year.

The performance model runs hourly or sub-hourly simulations to calculate the total annual energy value, which the financial model considers to be energy value for in Year One of the cash flow. SAM adjusts that value using the factors you specify on the Performance Adjustment page to account for expected system downtime for maintenance, and degradation of system performance over time.

Note. The annual energy value reported for Year one in the cash flow is not equal to the sum of the hourly energy values because the hourly values do not account for the **Percent of annual output** factor from the Performance Adjustment page.

For Year One, *Energy* is the value is calculated by the performance model:

Energy in Year One = Sum of Simulation Values x Percent of Annual Output

Where *Sum of Simulation Values* is the system's total annual electrical output (or energy saved) equal to the sum of the values calculated by the performance model (8,760 values for hourly simulations), and *Percent of Annual Output* is from the Performance Adjustment page.

Notes.

If you specify *Availability* on the Performance Adjustment page using the annual schedule option, SAM applies the value you specified for each year to the Year One Energy value:

Energy in Year n>1 = Energy in Year One × Availability in Year n

The Geothermal Power performance model runs simulations for each year of the analysis period rather than only for Year One. For the Geothermal Power model:

Energy in Year n = Energy in Year n × Availability in Year n

For Years 2 and later:

Energy in Year n>1 = Energy in Year n-1 × (1 - Year-to-Year Decline in Output)

Where *Energy in Year n-1* is the previous year's energy value and *Year-to-Year Decline* is from the Performance Adjustment page.

Note. If you specified **Year-to-year decline in output** on the Performance Adjustment page using the annual schedule option, SAM applies the value as follows (after applying the appropriate availability factor to calculate the Year One energy value):

Energy in Year n>1 = Energy in Year n × (1 - Year-to-Year Decline in Output in Year n)

PPA price (cents/kWh)

The PPA price in Year One is either the value you specify on the Financing page, or the value calculated by SAM to meet the IRR target you specify on the Financing page. The PPA price in Year One is the PPA price:

PPA Price in Year One = Adjusted PPA Price

For analyses that do not involve time-dependent pricing, *Adjusted PPA Price* is equal to the PPA Price reported on the Metrics table.

For analyses that do involve time-dependent pricing, for each hour of the year, SAM multiplies the PPA price shown in the Metrics table (equivalent to the bid price) by the TOD factor for that hour to calculate a set of hourly energy prices for Year one. The *Adjusted PPA Price* is the average of the 8,760 hourly values.

Notes.

When you choose **Specify PPA Price** for **Solution Mode** on the Financing page, the PPA Price in the Metrics table is equal to the price you specify. When you choose **Specify IRR Target**, SAM calculates the PPA price required to meet the IRR target that you specify.

The TOD factors are on the Thermal Energy Storage page for CSP systems (parabolic trough, power tower, linear Fresnel, generic solar system), and on the Time of Delivery Factors page for photovoltaic and other systems.

To remove time-dependent pricing from your analysis, set the TOD factor for each of the 9 periods to one.Where Adjusted PPA Price is either the value you specify on the Financing page, or a value calculated to cover project costs based on the target IRR you specify on the Financing page, adjusted by the time-of-delivery (TOD) factors.

In Years Two and later:

PPA Price in Year n>1 = PPA Price in Year n-1 × (1 + PPA Escalation Rate)^(n-1)

Where *PPA Escalation Rate* is from the Financing page.

Note. SAM uses the PPA Price to calculate the levelized cost of energy.

Total PPA revenue

The total PPA revenue is the project's annual revenue from electricity sales, not accounting for salvage value:

Total PPA Revenue = Net Energy (kWh) × PPA Price (cents/kWh) × 0.01 ($/cents)

Salvage value

SAM calculates the net salvage value using the percentage you specify on the Financing page and the total installed cost from the System Costs page. The salvage value applies in the final year of the project cash flow.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period

For residential projects, the salvage value has no effect on federal and state income tax because operating expenses are not taxable.

For commercial projects, because the salvage value reduces the operating expenses in the final year of the analysis period, it increases the federal and state income tax payment because operating expenses are deductible from federal and state income tax.

Total revenue

The projects annual revenue, accounting for salvage value.

Total Revenue = Total PPA Revenue + Salvage Value

Because Salvage Value is zero for all years except the last year of the analysis period, the Total Revenue and Total PPA Revenue are the same for all years except for the last year.

For the Single Owner and Leveraged Partnership Flip financing options (both of which include debt), total revenue may also include production-based incentive (PBI) amounts. For each PBI amount that you check on the Financing page under **Debt Service**, **Production Based Incentives (PBI) Available for Debt Service**, SAM displays a row for the PBI above the Total Revenue row, and includes the amount in the Total Revenue amount:

Total Revenue = Total PPA Revenue + Salvage Value + PBI

Expenses

The eight expense rows are for annual project costs calculated from assumptions you specify on the Financing and System Costs pages.

The four O&M expenses are based on the first year or annual schedule costs you specify under Operation and Maintenance Costs on the System Costs page, and are adjusted by the inflation rate from the Financing page and optional escalation rate from the System Costs page.

O&M Fixed expense

O&M Fixed Expense in Year n = Fixed Annual Cost ($) × (1 + Inflation Rate + Escalation Rate) ^ n-1

Where *Fixed Annual Cost* is from the System Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

O&M Capacity-based expense

O&M Capacity-based Expense in Year n = Fixed Cost by Capacity ($/kW-yr) × System Rated Capacity × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Fixed Cost by Capacity* is from the System Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 27. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

O&M Production-based expense

*O&M Production-based Expense in Year n = Variable Cost by Generation ($/MWh) × Net Energy in Year n (MWh) * (1 + Inflation Rate + Escalation Rate)^(n-1)*

Where *Variable Cost by Generation* is from the System Costs page, *Net Energy* is described above, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

O&M Fuel expense

The following performance models include a fuel cost calculation:

- Parabolic trough (physical or empirical) with fossil backup
- Power tower with fossil backup
- Generic solar system with fossil backup
- Generic system for the primary fuel cost
- Biomass Power for biomass and supplementary coal feedstock costs

> **Note.** For the CSP systems listed above, SAM only considers the system to have a fossil-fired backup boiler when the fossil fill fraction variable on the Thermal Storage page is greater than zero.

For solar and generic systems listed above that consume a fuel, Fuel O&M is the annual fuel cost:

Fuel O&M in Year n = Annual Fuel Usage in Year One (kWh) × 0.003413 MMBtu per kWh × Fossil Fuel Cost ($/MMBtu) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Annual Fuel Usage in Year One* is the quantity of fuel consumed in Year One calculated by the performance model. *Fossil Fuel Cost* and *Escalation Rate* are from the System Costs page, and Inflation Rate is from the Financing page.

> **Note.** When you specify fuel costs using an annual schedule instead of a single value, SAM does not apply the inflation rate or escalation rate to the values you specify for each year.

For the biomass power model, SAM calculates feedstock and coal costs using feedstock usage and price values from the Feedstock Costs page:

Biomass Feedstock Costs in Year n = Total Biomass Fuel Usage in Year One (dry tons/year) × Biomass Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Coal Feedstock Costs in Year n = Total Coal Fuel Usage in Year One (dry tons/year) × Coal Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where the fuel usage and fuel costs are from the Feedstock Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

Insurance expense

The insurance cost applies in Year One and later of the cash flow:

Insurance in Year n = Total Installed Costs ($) × Insurance (%) × (1 + Inflation Rate)^(n-1)

Where *Total Installed Costs* is the value from the System Costs page, and Insurance and Inflation Rate are specified on the Financing page.

Property tax net assessed value

The property assessed value is the value SAM uses as a basis to calculate the annual property tax payment:

Property Assessed Value in Year One = Assessed Value

Where *Assessed Value* is from the Financing page.

In Years 2 and later, the property assessed value is the Year One value adjusted by the assessed value decline value from the Financing page:

Property Assessed Value in Year n>1 = Assessed Value in Year One × [1 - Assessed Value Decline × (n-1)]

Where *Assessed Value Decline* is from the Financing page, expressed as a fraction instead of a percentage.

If the value of *1 - Assessed Value Decline* × *(n-1)* for a given year is equal to zero or less, then the *Property Assessed Value* in that year is zero.

Property tax expense

Property taxes apply in Year One and later of the cash flow:

Property Taxes in Year n = Property Assessed Value in Year n ($) × Property Tax (%)

Where *Property Assessed Value* is described above, and *Property Tax* is from the Financing page.

Annual Developer (Lessee LLC) Margin (Sale Leaseback only)

Annual Developer Margin in Year n = Developer Operating Margin × (1 + Developer Margin Escalation)^(n-1)

Where *Developer Operating Margin* and *Developer Margin Escalation* are from the Financing page.

Total operating expense

The total operating expense is the sum of expenses:

Total Operating Expense in Year n = O&M Fixed Expense + O&M Capacity-based Expense + O&M Production-based Expense + O&M Fuel Expense + Insurance Expense + Property Tax Expense

EBITDA ($)

Earnings before interest, taxes, depreciation and amortization:

EBITDA = Total Revenue - Total Operating Expense

Where *Total Revenue* and *Total Operating Expense* are described above.

Cash Flow: Project

The project cash flows include those from operating activities, investing activities, incentives, and issuance of equity. The pre-tax cash flow is the total project cash flow.

Project Cash Flows from Operating Activities

The cash flow from operating activities are the project earnings including interest on reserves and production-based incentives payments less interest paid on debt.

EBITDA

The earnings before interest, taxes, depreciation and amortization described above.

Interest on reserves

Interest on Reserves = Total Reserves ($) × Interest on Reserves (%)

Where *Total Reserves* is the sum of *Major Equipment Reserves*, *Working Capital Reserve*, and *Debt*

Service Reserves, and *Interest on Reserves* is from the Financing page.

PBI (Federal, State, Utility, Other, Total)

These values represent income from production-based incentive payments, calculated as described below under Incentives.

Total project cash flow from operating activities

Total = EBITDA + Interest on Reserves + Total PBI - Interest

Project Cash Flows from Investing Activities

Purchase of property cost

The purchase of property cost applies only in Year Zero of the cash flow.

Purchase of Property Cost = Total Installed Cost + Debt Service Reserve + Working Capital Reserve

Where *Total Installed Cost* is from the System Costs page, and *Debt Service Reserve* and *Working Capital Reserve* are the total reserve amounts described below.

(Increase)/Decrease in working capital reserve account

The working capital reserve amount in Year Zero depends on the Months of Operating Costs from the Financing page and the Year One total operating expense:

Capital Reserve in Year Zero = Total Operating Expense in Year One ($) × Months of Operating Costs (months) ÷ 12 (months)

In Year One and later:

Capital Reserve in Year n>0 = Capital Reserve in Year n-1 ($) - Total Operating Expense in Year n ($) × Months of Operating Costs (months) ÷ 12 (months)

Where *Months of Operating Costs* is from the Financing page.

(Increase)/Decrease in major equipment reserve accounts

For each of the up to three major equipment reserve accounts that you specify on the Financing page, SAM calculates the annual amount required to ensure that sufficient funds are available in the replacement year to cover the replacement cost:

For example, in the example described below under Major Equipment Capital Spending, the annual increase in reserves is $530,682/year = $2,653,400 ÷ 5 years.

Increase in Major Equipment Reserve = Inflation Adjusted Replacement Cost in Replacement Year ($) ÷ Replacement Year (year)

The increase is shown in the cash flow as a negative value.

In the year that the replacement occurs (in this example, Year 5), the decrease in major equipment reserve account is $2,122,727 = $2,653,400 - $430,682.

Decrease in Major Equipment Reserve in Replacement Year = Inflation Adjusted Replacement Cost in Replacement Year - Increase in Major Equipment Reserve

The decrease is shown in the cash flow as a positive value.

Major equipment capital spending

For each of the up to three major equipment reserve accounts that you specify on the Financing page, the inflation-adjusted amount is reported in the year that you specify.

For example, if you specify a $2,500 (in Year One dollars) replacement cost with a 5 year replacement frequency, and an inflation rate of 1.5% on the Financing page, SAM reports a major equipment capital spending amounts in years 5, 10, 15 etc. For Year 5, the amount would be \$2,653,400 = \$2,500,000 × (1 + 0.015)^4.

In each year that the replacement occurs:

Capital Spending = - Replacement Cost (Year One $) × (1 + Inflation Rate)^(Replacement Year - 1)

The value is negative because it represents an expense or outflow.

Total project cash flow from investing activities

The total cash flow from investing activities is the sum of purchase property cost, reserve account deposits or withdrawals, and capital spending:

Total in Year Zero = Purchase of Property Cost + Major Equipment Reserve Account

Total in Year n>0 = Major Equipment Reserve Account + Major Equipment Capital Spending

Project Cash Flows from Financing Activities

Cash flows from financing activities include income from incentive payments, equity capital, and, for Single Owner and Leveraged Partnership Flip, debt capital.

Total IBI

The total investment-based incentive amount, described below.

Total CBI

The total capital-based incentive amount, described below.

Equity Capital

The equity capital invested in the project.

Issuance of Equity in Year Zero = Total Installed Cost + Financing Cost - (Debt Funding + Total IBI + Total CBI)

Where *Total Installed Cost* is the project capital cost from the System Costs page, *Financing Cost* is from the Metrics table, *Debt* (Single Owner and Leveraged Partnership Flip only) is the debt funding amount described below, and *Total IBI* and *Total CBI* are the investment-based incentive and capacity based incentive amounts described below.

Total project cash flow from financing activities

The total cash flow from financing activities is the sum of equity capital, incentive payments, and debt capital.

Total in Year Zero = Issuance of Equity + Total IBI + Total CBI + Debt Funding

Total in Year n>0 = Debt Repayment

Project total pre-tax cash flow

The pre-tax cash flow is the cash flow and accounts for operating expenses, investment earnings, and incentive payments.

Total Project Pre-tax Cash Flow in Year Zero = Issuance of Equity

Where *Issuance of Equity* is the equity investment in the project described above.

Total Project Pre-tax Cash Flow in Year n>0 = Total Cash Flows from Operating Activities + Total Cash Flows from Investing Activities + Total Incentives

Total Project Returns

The total project returns rows of the cash flow table show pre- and after-tax cash flows and returns from the project perspective. Returns from each partner's perspective appear under the Partners Returns heading and are described below.

Project pre-tax returns

Total project pre-tax returns

The total annual pre-tax cash flow is the cash flow and accounts for operating expenses, investment earnings, and incentive payments.

Pre-tax Cash Flow in Year Zero = Issuance of Equity

Where *Issuance of Equity* is the equity investment in the project described above.

Pre-tax Cash Flow in Year n>0 = Total Cash Flows from Operating Activities + Total Cash Flows from Investing Activities + Total Incentives

Project pre-tax cumulative IRR

SAM calculates the cumulative IRR for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the pre-tax cash flow described above.

Project pre-tax cumulative NPV

The cumulative net present value in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the pre-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Project after-tax returns

Cash

The pre-tax cash flow, described above.

Total project after-tax returns

The total annual after-tax cash flow is the sum of the pre-tax cash flow and tax credits less income tax payments:

After-tax Cash Flow in Year Zero = Pre-tax Cash Flow in Year Zero

After-tax Cash Flow in Year One = Pre-tax Cash Flow in Year One + Total ITC + Total PTC + Project Tax Benefit

After-tax Cash Flow in Year n>1 = Pre-tax Cash Flow in Year n + Total PTC + Project Tax Benefit

Project after-tax cumulative IRR

SAM calculates the cumulative IRR for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+IRR)^n} = 0$$

Where $C_{AfterTax,n}$ is the after-tax cash flow described above.

Project after-tax cumulative NPV

The cumulative net present value in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+d_{nominal})^n}$$

Where $C_{AfterTax,n}$ is the after-tax cash flow described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

Project LCOE

SAM reports quantities used in the LCOE calculation in the cash flow table for reference. For a description of the LCOE see Levelized Cost of Energy (LCOE).

Project PPA revenue

The total PPA revenue is the project's annual revenue from electricity sales, not accounting for salvage value:

Project PPA Revenue = Net Energy (kWh) × PPA Price (cents/kWh) ÷ 100 (cents/$)

Net Energy (kWh)

The total amount of electricity generated by the system in AC kilowatt-hours for each year. See description above

NPV of PPA revenue

The present value of the annual PPA revenue streams over the analysis period used as the numerator of the LCOE equation:

$$\text{NPV(Revenue)} = \sum_{n=0}^{N} \frac{R_{PPA,n}}{(1+d_{nominal})^n}$$

Where $R_{PPA,n}$ is the revenue from electricity sales-tax cash flow described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

NPV of net annual energy (nominal)

The LCOE calculation requires a discounted energy term in the denominator. The value discounted using the nominal discount rate is for the nominal LCOE equation.

$$\text{NPV(Energy Nominal)} = \sum_{n=0}^{N} \frac{Q_n}{(1 + d_{nominal})^n}$$

Where Q_n is the annual energy value described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

Project Nominal LCOE

Project Nominal LCOE = NPV(Revenue) / NPV(Energy Nominal)

NPV of net annual energy (real)

The LCOE calculation requires a discounted energy term in the denominator. The value discounted using the real discount rate is for the real LCOE equation.

$$\text{NPV(Energy Real)} = \sum_{n=0}^{N} \frac{Q_n}{(1 + d_{real})^n}$$

Where Q_n is the annual energy value described above, and d_{real} is the nominal discount rate from the Financing page.

Project Real LCOE

Project Real LCOE = NPV(Revenue) / NPV(Energy Real)

Partners Returns

The partners returns are the IRR, NPV, and taxes from each project partner's perspective.

Tax Investor

The tax investor cash flows represent the tax investor share of project cash flows.

Tax Investor Pre-Tax Returns

Total tax investor pre-tax returns

In Year Zero, the tax investor pre-tax cash flow is the portion of equity capital allocated to the tax investor:

Tax Investor Pre-Tax Cashflow in Year Zero = Tax Investor Share of Equity Contribution (%) × Issuance of Equity ($)

Where *Tax Investor Share of Equity Contribution* is from the Financing page.

For years before the flip target is reached:

Tax Investor Pre-Tax Cashflow in Year n>1 = Tax Investor Pre-flip Share of Project Cash (%) × Total Project Pre-tax Cash Flow ($)

For years after the flip target is reached:

Tax Investor Pre-Tax Cashflow in Year n>1 = Tax Investor Post-flip Share of Project Cash (%) × Total Project Pre-tax Cash Flow ($)

Where the pre- and post-flip share of project cash percentages are from the Financing page.

Tax investor cumulative IRR

Cumulative pre-tax IRR from the tax investor perspective for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the tax investor pre-tax cash flow described above.

For years when there is no mathematical solution, SAM reports a value of zero.

Tax investor cumulative NPV

Cumulative pre-tax net present value from the tax investor perspective in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the tax investor pre-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Tax Investor After-Tax Returns

Tax investor cash (total pre-tax returns)

The tax investor pre-tax cash flow, described above.

ITC

The tax investor's share of the ITC amount applies to the tax investor's Year One cash flow:

Investment Tax Credit in Year One = Tax Investor Share of Equity Contribution (%) × *(Federal ITC ($) + State ITC ($))*

Where *Tax Investor Share of Equity Contribution* is from the Financing page, and *Federal ITC* and *State ITC* are described below.

PTC

The tax investor's share of the PTC applies in Years One and later of the tax investor's cash flow.

For years before the flip target is reached:

Production Tax Credit in Year n = Tax Investor Pre-flip Share of Project Cash (%) × *(Federal PTC ($) + State PTC ($))*

For years after the flip target is reached:

Production Tax Credit in Year n = Tax Investor Post-flip Share of Project Cash (%) × *(Federal PTC ($) + State PTC ($))*

Where the pre- and post-flip share of project cash values are from the Financing page, and *Federal PTC* and *State PTC* are described below.

Tax investor share of project tax

The tax investor's share of the project's tax payment or refund. A positive value indicates a tax refund, and a negative value indicates a tax payment.

For years before the flip target is reached:

Tax Investor Share of Project Tax in Year n = Tax Investor Pre-flip Share of Project Cash (%) × Project Tax Benefit/(Liability) ($)

For years after the flip target is reached:

Tax Investor Share of Project Tax in Year n = Tax Investor Post-flip Share of Project Cash (%) × Project Tax Benefit/(Liability) ($)

Where the pre- and post-flip share of project cash values are from the Financing page, and Project Tax Benefit/(Liability) is the tax amount owed.

Total tax investor after-tax returns

The tax investor's total after-tax cash flow.

Total = Cash + Investment Tax Credit + Production Tax Credit + Share of Project Tax Benefit/(Liability)

Tax investor cumulative IRR

Cumulative after-tax IRR from the tax investor perspective for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the tax investor after-tax cash flow described above.

For years when there is no mathematical solution, SAM reports a value of zero.

Tax investor cumulative NPV

Cumulative after-tax net present value from the tax investor perspective in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the tax investor after-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Tax investor maximum IRR

The greater of the Year One Cumulative IRR and the Year n Cumulative IRR.

Developer

The Developer cash flows represent the developer share of project cash flows.

Developer Pre-Tax Returns

Pre-tax development fee

A fee received by the developer.

Pre-tax Developer Development Fee in Year Zero = Development Fee

Where *Development Fee* is from the Financing page.

Total developer pre-tax returns

The pre-tax cash flow from the developer's perspective.

Developer Pre-tax Cash Flow in Year Zero = Equity Investment in Year Zero + Pre-tax Developer Development Fee

Developer Pre-tax Cash Flow in Year n>0 = Total Project After-tax Cash Flow - Tax Investor Pre-tax Cash Flow

Developer pre-tax cumulative IRR

Cumulative pre-tax IRR from the developer perspective for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the tax investor after-tax cash flow described above.

For years when there is no mathematical solution, SAM reports a value of zero.

Developer pre-tax cumulative NPV

Cumulative pre-tax net present value from the developer perspective in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the tax investor after-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Developer pre-tax IRR

The cumulative tax investor pre-tax IRR in the flip year defined on the Financing page.

For years when there is no mathematical solution, SAM reports a value of zero.

Developer pre-tax NPV

The cumulative tax investor pre-tax NPV in the flip year defined on the Financing page.

Developer After-Tax Returns

Equity Investment

The developer's share of the project equity capital.

Equity Investment in Year Zero = Total Project Equity Investment in Year Zero - Tax Investor Equity Investment in Year Zero

Development Fee

A fee received by the developer.

Development Fee in Year Zero = Development Fee

Where *Development Fee* is from the Financing page.

Cash

The pre-tax cash flow from the developer perspective.

Cash in Year Zero = Equity Investment + Development Fee

Cash in Year n>0 = Developer Pre-tax Cash Flow

ITC

The developer's share of the ITC amount applies to the tax developer's Year One cash flow:

Investment Tax Credit in Year One = Developer Share of Equity Contribution (%) × (Federal ITC ($) + State ITC ($))

Where *Developer Share of Equity Contribution* is from the Financing page, and *Federal ITC* and *State ITC* are described below.

PTC

The developer's share of the PTC applies in Years One and later of the developer's cash flow.

For years before the flip target is reached:

Production Tax Credit in Year n = Developer Pre-flip Share of Project Cash (%) × (Federal PTC ($) + State PTC ($))

For years after the flip target is reached:

Production Tax Credit in Year n = Developer Post-flip Share of Project Cash (%) × (Federal PTC ($) + State PTC ($))

Where the pre- and post-flip share of project cash values are from the Financing page, and *Federal PTC* and *State PTC* are described below.

Developer share of project tax

The developer's share of the project's tax payment or refund. A positive value indicates a tax refund, and a negative value indicates a tax payment.

For years before the flip target is reached:

Developer Share of Project Tax in Year n = Developer Pre-flip Share of Project Cash (%) × Project Tax Benefit/(Liability) ($)

For years after the flip target is reached:

Developer Share of Project Tax in Year n = Developer Post-flip Share of Project Cash (%) × Project Tax Benefit/(Liability) ($)

Where the pre- and post-flip share of project cash values are from the Financing page

Total developer after-tax returns

The developer's total after-tax cash flow.

Total Developer After-tax Returns = Cash + Investment Tax Credit + Production Tax Credit + Share of Project Tax Benefit/(Liability)

Developer after-tax cumulative IRR

Cumulative after-tax IRR from the developer perspective for each year n of the cash flow. The cumulative IRR in a given Year n is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the developer after-tax cash flow described above.

For years when there is no mathematical solution, SAM reports a value of zero.

Developer after-tax cumulative NPV

Cumulative after-tax net present value from the developer perspective in a given Year n is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the developer after-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Developer after-tax IRR

The cumulative developer pre-tax IRR in the flip year defined on the Financing page.

For years when there is no mathematical solution, SAM reports a value of zero.

Developer after-tax NPV

The cumulative developer pre-tax NPV in the flip year defined on the Financing page.

Incentives

Incentives may consist of either cash incentives (IBI, CBI, PBI) or tax credits (ITC, PTC), and may either calculated based on project investment costs (IBI, CBI, ITC), or the project's energy production (PBI, PTC).

The values in the incentives rows of the cash flow table are shown for reference. Their impact on project cash flows are shown in the project cash flows described above:

- PBI income appears under **Cash Flows from Operating Activities**.
- IBI and CBI income appear under **Cash Flows from Investing Activities**.
- ITC and PTC amounts appear under **Partners Returns**, **Tax Investor**, **After-Tax**.

The incentive cash flow rows show the value of cash incentives and tax credits, which are used to calculate cash flows described above.

IBI (Investment Based Incentives)

Each IBI (federal, state, utility, other) applies in Year Zero of the project cash flow.

Because you can specify each IBI on the Incentives page as either an amount or a percentage, SAM calculates the value of each IBI as the sum of two values:

IBI as Amount = Amount

IBI as Percentage = Total Installed Cost ($) × Percentage (%), up to Maximum

IBI in Year 0 = IBI as Amount + IBI as Percentage

Where *Amount*, *Percentage* and *Maximum* are the values that you specify on the Incentives page, and *Total Installed Cost* is from the System Costs page.

Total IBI is the sum of the four IBI values (federal, state, utility, other).

> **Note.** The IBI amount reduces the after tax cost flow in Year Zero, and the debt balance in Year One. This is because SAM assumes that debt payments begin in Year One, when the project is generating or saving electricity.

CBI (Capacity Based Incentives))

Each CBI (federal, state, utility, other) applies in Year Zero of the project cash flow:

CBI in Year 0 = System Capacity (W) × Amount ($/W), up to Maximum

Where System Capacity is the rated capacity of the system, and *Amount* and *Maximum* are the values you specify on the Incentives page.

Total CBI is the sum of the four CBI values (federal, state, utility, other).

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 28. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

PBI (Performance Based Incentive)

Each PBI (federal, state, utility, other) applies in Years One and later of the project cash flow, up to the number of years you specify:

PBI in Year n = Amount ($/kWh) × Energy in Year n (kWh) × (1 + Escalation)^(n-1), up to Term

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in Energy row of the cash flow table (described above).

Note. If you use an annual schedule to specify year-by-year PBI amounts, SAM ignores the escalation rate.

Total PBI is the sum of the four PBI amounts (federal, state, utility, other).

Important Note! If you specify a PBI amount on the Cash Incentives page, be sure to also specify the incentive term. If you specify a term of zero, the incentive will not appear in the cash flow table.

PTC (Production Tax Credit)

The state and federal PTC each apply in Year One and later of the project cash flow, up to the number of years you specify:

PTC in Year n = Amount ($/kWh) × (1 + Escalation)^(n-1) × Energy in Year n (kWh)

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in the Energy row of the cash flow table (described above).

SAM rounds the product *Amount ($/kWh) × (1 + Escalation)^(n-1)* to the nearest multiple of 0.1 cent as described in Notice 2010-37 of IRS Bulletin 2010-18.

Note. If you specify year-by-year PTC rates on the Incentives page using an Annual Schedule instead of a single value, SAM ignores the PTC escalation rate.

ITC (Investment Tax Credit)

The state and federal ITC each apply only in Year One of the project cash flow. For ITCs that you specify as a fixed amount:

ITC in Year One = Amount

Where *Amount* is the value you specify in the Incentives page.

For ITCs that you specify as a percentage of total installed costs:

ITC in Year One = (Total Installed Cost ($) - ITC Basis Reduction ($)) × Percentage (%), up to Maximum

Where *Total Installed Cost* is from the System Costs page, and *Percentage* and *Maximum* are the values you specify on the Incentives page.

ITC Basis Reduction applies only to the Commercial and Utility financing options, and depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked boxes under **Reduces Depreciation and ITC Bases**. For each IBI or CBI with a check mark, SAM subtracts the incentive amount from the total installed cost to calculate the ITC.

ITC Basis Reduction = IBI + CBI

Where *IBI* and *CBI* are the incentives that you have specified reduce the ITC basis on the Incentives page.

Debt

The debt amounts depend on the following inputs from the Financing page:

- Debt Rate
- DSCR

Funding

The funding amount applies in Year Zero, and is the size of debt assuming the constant DSCR specified on the Financing page:

$$\text{Funding} = \sum_{n=1}^{N} \frac{\frac{CAFDS_n}{(1 + Debt\ Rate)^n}}{DSCR}$$

Where $CAFDS_n$ is the cash available for debt service in Year n, and *Debt Rate* and *DSCR* are from the Financing page.

CAFDS in Year n= EBIDTA in Year n - Sum of Major Equipment Replacement Reserves in Year n

Where EBIDTA and Major Equipment Reserves are described above and below, respectively.

Repayment

Repayment applies in Year One and later, and represents annual debt payments.

Repayment in Year n = - Principal in Year n

Where *Principal in Year n* is described below.

Ending Balance

The ending balance applies in Year Zero and later:

Ending Balance in Year Zero = Funding

Where *Funding* is described above.

Ending Balance in Year n = Ending Balance in Year n-1 + Repayment in Year n

Where *Repayment* is described above.

Principal

The principal applies in Year One and later:

Principal in Year n = Total P&I in Year n - Interest in Year n

Where *Total P&I* and *Interest* are described below.

Interest

The interest applies in Year One and later:

Interest in Year n = Ending Balance in Year n × Debt Rate

Where *Ending Balance* is described above, and *Debt Rate* is from the Financing page.

Total P&I

The total principal and interest applies in Year One and later:

Total P&I in Year n = CAFDS in Year n ÷ DSCR

Where *CAFDS in Year n* is described above (under Funding), and *DSCR* is from the Financing page.

Reserve Accounts

Reserve accounts include debt service, working capital reserve, and major equipment replacement reserves. The reserve account amounts depend on the following inputs from the Financing page:

- Inflation Rate
- Debt Service Reserve Account (months P&I)
- Working Capital Reserve Months of Operating Costs
- Major Equipment Replacement Reserve Account [1-3] Frequency (years)
- Major Equipment Replacement [1-3] (Year 1 $)

Lease Payment Reserve (Sale Leaseback only)

Lease Payment Reserve = Tax Investor (Lessor) Required Lease Payment Reserve (months) ÷ 12 × Total Developer Pre-tax Cash Flow from Operating Activities in Year n+1

Debt Service Reserve

The debt service reserve applies in Year Zero and later:

Debt Service Reserve = Debt Service Reserve Account (months P&I) ÷ 12 × Total P&I in Year n+1

Where *Debt Service Reserve Account (months P&I)* is from the Financing page, and *Total P&I in Year n+1* is described under Debt above.

Working Capital Reserve

Working capital reserve applies in Year Zero and later:

Working Capital Reserve = Months of Operating Costs × Operating Expenses in Year n+1

Where *Months of Operating Costs* is from the Financing page, and *Operating Expenses in Year n+1* is described above.

Major Equipment Replacement Reserves

You can specify up to three major equipment reserve accounts on the Financing page. For each account, the amount applies in Year One and later of the cash flow:

Major Equipment Reserve in Year n = Major Equipment Reserve in Year n-1 + Funding + Release of Funds

Where Major Equipment Reserve in Year Zero = 0, and:

Funding = Release of Funds in Year of Next Replacement ÷ Replacement Frequency

Release of Funds in Year of Next Replacement = - Replacement Cost in Year One $ × (1 + Inflation Rate)^(n-1)

Where *Replacement Frequency*, *Replacement Cost in Year One $*, and *Inflation Rate* are from the Financing page

Depreciation and ITC Tables

The federal and state Depreciation and ITC tables show the depreciable basis calculation for each of the up to seven depreciation classes for federal and state tax purposes:

- The total depreciable amount includes the total installed cost, development fee, equity closing cost, debt service reserve, working capital reserve, and for the Sale Leaseback financing option, the lease payment reserve.
- The depreciation class allocations on the Financing page determine how the depreciable basis is

allocated to the different depreciation classes (MACRS 5-yr, Straight Line, etc.).

- For each state and federal IBI and CBI with **Reduces Depreciation and ITC Bases** checked on the Incentives page, the full incentive amount reduces the depreciable basis.
- For each state and federal ITC with **Reduces Depreciation Basis** checked on the Incentives page, 50% of the tax credit amount reduces the depreciable basis.
- For each depreciation class with a checked box under **Bonus Depreciation** on the Financing page, the depreciable basis is the product of the bonus depreciation percentage and the adjusted depreciable basis. (The adjusted depreciable basis is the total depreciable after incentives and tax credit adjustments.)
- For state and federal taxes, depreciation for major equipment replacement reserves uses the class specified on the Financing page.

The depreciation amounts depend on the total installed cost from the System Costs page, and the following inputs from other pages.

From the Financing page:

- Development Fee
- Debt Closing Costs
- Debt Closing Fee
- Equity Closing Cost
- Construction Financing
- Other Financing Cost

From the Incentives page:

- State ITC as Percentage
- State ITC Maximum
- State ITC as Amount
- Federal ITC as Percentage
- Federal ITC Maximum
- Federal ITC as Amount
- Status of **Reduces Depreciation Basis** check boxes
- The amounts and percentages of any incentive with **Reduces Depreciation and ITC Bases** checked

From the Depreciation page:

- Allocations for each depreciation class
- Bonus depreciation amounts and applicable depreciation classes
- ITC qualification status of depreciation classes

The depreciation amounts also depend on the following cash flow values:

- Debt service reserve
- Working capital reserve
- IBI (only for incentives shown to reduce depreciation basis on Incentives page)
- CBI (only for incentives shown to reduce depreciation basis on Incentives page)
- Debt funding
- For state depreciation, the federal ITC basis disallowance amounts for each depreciation class
- For federal depreciation, the state ITC basis disallowance amounts for each depreciation class

Gross Depreciable Basis with IBI and CBI Reductions Before ITC Reductions

For each depreciable class, the depreciable basis before reduction by the ITC is the gross depreciable basis less IBI and CBI amounts for incentives on the Cash Incentives page with **Reduces Depreciation and ITC Bases** checked.

Note. The IBI and CBI reduce the depreciation basis for state taxes only when **State** under **Reduces Depreciation and ITC Bases** is checked. Similarly, the IBI and CBI reduce the depreciation basis for federal taxes only when **Federal** under **Reduces Depreciation and ITC Bases**.

% of Total Depreciable Basis

The normalized allocation for each depreciation class allocation:

% of Total Depreciable Basis = Allocation ÷ Sum of Allocations

Where *Allocation* is the percentage for the given depreciable class, and *Sum of Allocations* is the sum of all allocations from the Financing page.

Gross Amount Allocated

The gross depreciable basis before reductions for each depreciation class:

Gross Amount Allocated = % of Total Depreciable Basis × Total Depreciable Amount

Where % of Total Depreciable Basis is described above, and

Total Depreciable Amount = Total Installed Cost + Development Fee + Equity Closing Cost + Debt Closing Costs + Debt Closing Fee × Funding + Debt Service Reserve + Working Capital Reserve + Lease Payment Reserve

Where *Total Installed Cost* is from the System Costs page; *Development Fee*, *Equity Closing Cost*, *Debt Closing Costs*, and *Debt Closing Fee* are from the Financing page; and *Debt Service Reserve*, *Working Capital Reserve* and *Lease Payment Reserve* (Sale Leaseback financing option only) are other values in the cash flow described above

Reduction: IBI

The reduction in depreciation basis from IBI payments:

Reduction IBI = Total IBI that Reduce Depreciation × % of Total Depreciable Basis

Where *Total IBI that Reduce Depreciation* is the sum of IBI values in the cash flow for incentives with **Reduces Depreciation and ITC Bases** checked on the Incentives page. For the state depreciation table, **State** must be checked for the incentive to reduce the state depreciation basis. For the federal depreciation table, **Federal** must be checked. *% of Total Depreciable Basis* is the allocation for the depreciation class described above.

Reduction: CBI

The reduction in depreciation basis from CBI payments:

Reduction CBI = Total CBI that Reduce Depreciation × % of Total Depreciable Basis

Where *Total CBI that Reduce Depreciation* is the sum of CBI values in the cash flow for incentives with **Reduces Depreciation and ITC Bases** checked on the Incentives page. For the state depreciation table, **State** must be checked for the incentive to reduce the state depreciation basis. For the federal depreciation table, **Federal** must be checked. *% of Total Depreciable Basis* is the allocation for the depreciation class described above.

Depreciable Basis Prior to ITC

The depreciable basis reduced by CBI and IBI amounts:

Depreciable Basis Prior to ITC = Gross Amount Allocated - Reduction: IBI - Reduction: CBI

ITC Reduction

For each ITC on the Incentives page with **Reduces Depreciation Basis** checked, 50% of the ITC amount can be included in the depreciable basis for each depreciable class with **ITC Qualification** checked on the Depreciation page. SAM calculates the ITC reduction amount for ITCs that you specify on the Incentives page a percentage of the total installed costs with a maximum amount, and ITCs that you specify as a fixed amount.

Note. The ITC reduces the depreciation basis for state taxes only when **State** under **Reduces Depreciation Basis** is checked on the Incentives page, and when **State** is checked under **ITC Qualification** for the depreciation class on the Depreciation page. Similarly, the ITC reduces the depreciation basis for federal taxes only when **Federal** is checked under **Reduces Depreciation Basis** and under **ITC Qualification** for the depreciation class.

For each ITC specified as a percentage and maximum on the Incentives page, the *ITC Basis Disallowance* is the amount that may be available for depreciation basis reduction. (The ITC Reduction amounts are the amounts actually available.):

ITC Qualifying Costs

For depreciation classes with **ITC Qualification** checked on the Depreciation page:

ITC Qualifying Costs = Depreciable Basis Prior to ITC

% of ITC Qualifying Costs

For each depreciable class:

% of ITC Qualifying Costs = ITC Qualifying Costs ÷ Total Depreciable Basis Prior to ITC

Where *Total Depreciable Basis Prior* to ITC is the sum of *Depreciable Basis Prior to ITC* for all depreciable classes.

ITC Amount

ITC Amount = % of ITC Qualifying Costs × ITC Qualifying Costs

ITC Basis Disallowance

The ITC depreciation basis disallowance is 50% of the ITC amount:

ITC Basis Disallowance = ITC Amount × 0.5

For each ITC specified as a fixed amount on the Incentives page, the ITC Basis Disallowance is the amount that may be available for depreciation basis reduction. (The ITC Reduction amounts are the amounts actually available.):

ITC Amount

For each depreciable class, the Total ITC Amount is the amount that may be available for depreciation reduction:

ITC Amount = Total ITC Amount × % of ITC Qualifying Costs

Where, for the state depreciation table, *Total ITC Amount* is the state ITC amount from the Incentives page. For the federal depreciation table, *Total ITC Amount* is the federal ITC amount from the Incentives page.

ITC Basis Disallowance

The ITC depreciation basis disallowance is 50% of the ITC amount:

ITC Basis Disallowance = ITC Amount × 0.5

The depreciable basis after ITC reduction is the sum of the total ITC basis disallowance values for the ITCs with **Reduces Depreciation Basis** checked on the Incentives pages.

ITC Reduction: State

ITC Reduction: State = ITC Basis Disallowance (ITC as %) + ITC Basis Disallowance (ITC as Fixed Amount)

Where the ITC basis disallowance values are from the state depreciation table for the ITCs that reduce depreciation basis.

ITC Reduction: Federal

ITC Reduction: Federal = ITC Basis Disallowance (ITC as %) + ITC Basis Disallowance (ITC as Fixed Amount)

Where the ITC basis disallowance values are from the federal depreciation table for the ITCs that reduce depreciation basis.

Depreciable Basis after ITC Reduction

Depreciable Basis after ITC Reduction = Depreciable Basis Prior to ITC - ITC Reduction:State - ITC Reduction:Federal

Bonus Depreciation

For each depreciation class that qualifies for bonus depreciation as indicated by the check boxes under Bonus Depreciation on the Depreciation page, bonus depreciation percentage applies to the depreciable basis.

> **Note.** The bonus depreciation percentage applies to the depreciation basis for state taxes only when **State** under **Bonus Depreciation** is checked. Similarly, the bonus depreciation percentage applies for federal taxes only when **Federal** under **Reduces Depreciation Basis** is checked.

First Year Bonus Depreciation

For each depreciation class with **Bonus Depreciation** checked on the Depreciation page:

First Year Bonus Depreciation = Depreciable Basis after ITC Reduction × Bonus Depreciation Percentage

Where Bonus Depreciation Percentage is from the Depreciation page: The state bonus percentage applies to the state depreciation table, and the federal percentage applies to the federal depreciation table.

Depreciable Basis

The depreciable basis after IBI, CBI, ITC and bonus depreciation reduction is the basis to which the depreciation percentages defined by the depreciation class apply.

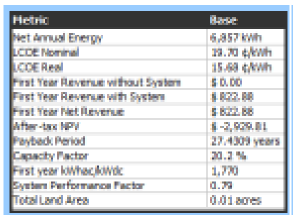
Depreciable Basis after Bonus Reduction = Depreciable Basis after ITC Reduction - First Year Bonus Depreciation

The following table shows the depreciation percentage by year for each depreciation class. For each depreciation class, the percentage is applied to the depreciable basis amount for the given year in the cash flow:

Years 1-10	1	2	3	4	5	6	7	8	9	10
5-yr MACRS	20.0	32.0	19.2	11.5	11.5	5.8				
15-yr MACRS	5.0	9.5	8.6	7.7	6.9	6.2	5.9	5.9	5.9	5.9
5-yr SL	10.0	20.0	20.0	20.0	20.0	10.0				
15-yr SL	3.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
20-yr SL	2.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	1.3	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 11-20	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
15-yr MACRS	5.9	5.9	5.9	5.9	5.9	3.0				
15-yr SL	6.7	6.7	6.7	6.7	6.7	3.3				
20-yr SL	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 21-30	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
20-yr SL	2.5									
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 31-40	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	1.3

20.5 Leveraged Partnership Flip

This topic describes the cash flow table generated by the financial model for the Utility Leveraged Partnership Flip financing option. See Financing Overview for details.



Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

SAM offers three options for exporting the cash flow table:

- **Copy to clipboard** copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.
- **Save as CSV** saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.
- **Send to Excel (Windows only)** creates a new Excel file that contains the data from the cash flow table in an Excel file, but no formulas.
- **Send to Excel with Equations (Windows only)** exports the cash flow data to an existing Excel workbook that contains formulas to illustrate how SAM's internal cash flow calculations work. The workbooks are in the *\exelib\spreadsheets\equations* folder of your SAM installation folder.

Notes.

SAM makes cash flow calculations internally during simulations. It does not use Excel to make the calculations. The two **Send to Excel** options are to help you analyze the cash flow data and understand how SAM's internal calculations work.

You can also display cash flow data by building a Table. This option allows you to choose the rows to include in the table, and also makes it possible to show cash flow results from a parametric analysis.

Project Revenue

The partial income statement rows show the annual revenue to the project as a whole. For projects with multiple partners, this revenue is the total revenue, before allocations to the different partners.

Net Energy (kWh)

For systems that generate electricity, *Energy* is the total amount of electricity generated by the system in AC kilowatt-hours for each year.

For solar water heating systems, *Energy* is the amount of electricity saved by the solar water heating system in AC kilowatt-hours for each year.

The performance model runs hourly or sub-hourly simulations to calculate the total annual energy value, which the financial model considers to be energy value for in Year One of the cash flow. SAM adjusts that value using the factors you specify on the Performance Adjustment page to account for expected system downtime for maintenance, and degradation of system performance over time.

Note. The annual energy value reported for Year one in the cash flow is not equal to the sum of the hourly energy values because the hourly values do not account for the **Percent of annual output** factor from the Performance Adjustment page.

For Year One, *Energy* is the value is calculated by the performance model:

Energy in Year One = Sum of Simulation Values x Percent of Annual Output

Where *Sum of Simulation Values* is the system's total annual electrical output (or energy saved) equal to the sum of the values calculated by the performance model (8,760 values for hourly simulations), and *Percent of Annual Output* is from the Performance Adjustment page.

Notes.

If you specify *Availability* on the Performance Adjustment page using the annual schedule option, SAM applies the value you specified for each year to the Year One Energy value:

Energy in Year n>1 = Energy in Year One × Availability in Year n

The Geothermal Power performance model runs simulations for each year of the analysis period rather than only for Year One. For the Geothermal Power model:

Energy in Year n = Energy in Year n × Availability in Year n

For Years 2 and later:

Energy in Year n>1 = Energy in Year n-1 × (1 - Year-to-Year Decline in Output)

Where *Energy in Year n-1* is the previous year's energy value and *Year-to-Year Decline* is from the

Performance Adjustment page.

Note. If you specified **Year-to-year decline in output** on the Performance Adjustment page using the annual schedule option, SAM applies the value as follows (after applying the appropriate availability factor to calculate the Year One energy value):

Energy in Year n>1 = Energy in Year n × (1 - Year-to-Year Decline in Output in Year n)

PPA price (cents/kWh)

The PPA price in Year One is either the value you specify on the Financing page, or the value calculated by SAM to meet the IRR target you specify on the Financing page. The PPA price in Year One is the PPA price:

PPA Price in Year One = Adjusted PPA Price

For analyses that do not involve time-dependent pricing, *Adjusted PPA Price* is equal to the PPA Price reported on the Metrics table.

For analyses that do involve time-dependent pricing, for each hour of the year, SAM multiplies the PPA price shown in the Metrics table (equivalent to the bid price) by the TOD factor for that hour to calculate a set of hourly energy prices for Year one. The *Adjusted PPA Price* is the average of the 8,760 hourly values.

Notes.

When you choose **Specify PPA Price** for **Solution Mode** on the Financing page, the PPA Price in the Metrics table is equal to the price you specify. When you choose **Specify IRR Target**, SAM calculates the PPA price required to meet the IRR target that you specify.

The TOD factors are on the Thermal Energy Storage page for CSP systems (parabolic trough, power tower, linear Fresnel, generic solar system), and on the Time of Delivery Factors page for photovoltaic and other systems.

To remove time-dependent pricing from your analysis, set the TOD factor for each of the 9 periods to one.Where Adjusted PPA Price is either the value you specify on the Financing page, or a value calculated to cover project costs based on the target IRR you specify on the Financing page, adjusted by the time-of-delivery (TOD) factors.

In Years Two and later:

PPA Price in Year n>1 = PPA Price in Year n-1 × (1 + PPA Escalation Rate)^(n-1)

Where *PPA Escalation Rate* is from the Financing page.

Note. SAM uses the PPA Price to calculate the levelized cost of energy.

Total PPA revenue

The total PPA revenue is the project's annual revenue from electricity sales, not accounting for salvage value:

Total PPA Revenue = Net Energy (kWh) × PPA Price (cents/kWh) × 0.01 ($/cents)

Salvage value

SAM calculates the net salvage value using the percentage you specify on the Financing page and the total installed cost from the System Costs page. The salvage value applies in the final year of the project cash flow.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period

For residential projects, the salvage value has no effect on federal and state income tax because operating expenses are not taxable.

For commercial projects, because the salvage value reduces the operating expenses in the final year of the analysis period, it increases the federal and state income tax payment because operating expenses are deductible from federal and state income tax.

Total revenue

The projects annual revenue, accounting for salvage value.

Total Revenue = Total PPA Revenue + Salvage Value

Because Salvage Value is zero for all years except the last year of the analysis period, the Total Revenue and Total PPA Revenue are the same for all years except for the last year.

For the Single Owner and Leveraged Partnership Flip financing options (both of which include debt), total revenue may also include production-based incentive (PBI) amounts. For each PBI amount that you check on the Financing page under **Debt Service**, **Production Based Incentives (PBI) Available for Debt Service**, SAM displays a row for the PBI above the Total Revenue row, and includes the amount in the Total Revenue amount:

Total Revenue = Total PPA Revenue + Salvage Value + PBI

Project Expenses

The eight expense rows are for annual project costs calculated from assumptions you specify on the Financing and System Costs pages.

The four O&M expenses are based on the first year or annual schedule costs you specify under Operation and Maintenance Costs on the System Costs page, and are adjusted by the inflation rate from the Financing page and optional escalation rate from the System Costs page.

O&M Fixed expense

O&M Fixed Expense in Year n = Fixed Annual Cost ($) × (1 + Inflation Rate + Escalation Rate) ^ n-1

Where *Fixed Annual Cost* is from the System Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

O&M Capacity-based expense

O&M Capacity-based Expense in Year n = Fixed Cost by Capacity ($/kW-yr) × System Rated Capacity × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Fixed Cost by Capacity* is from the System Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 29. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

O&M Production-based expense

*O&M Production-based Expense in Year n = Variable Cost by Generation ($/MWh) × Net Energy in Year n (MWh) * (1 + Inflation Rate + Escalation Rate)^(n-1)*

Where *Variable Cost by Generation* is from the System Costs page, *Net Energy* is described above, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

O&M Fuel expense

The following performance models include a fuel cost calculation:

- Parabolic trough (physical or empirical) with fossil backup
- Power tower with fossil backup
- Generic solar system with fossil backup
- Generic system for the primary fuel cost
- Biomass Power for biomass and supplementary coal feedstock costs

Note. For the CSP systems listed above, SAM only considers the system to have a fossil-fired backup boiler when the fossil fill fraction variable on the Thermal Storage page is greater than zero.

For solar and generic systems listed above that consume a fuel, Fuel O&M is the annual fuel cost:

Fuel O&M in Year n = Annual Fuel Usage in Year One (kWh) × 0.003413 MMBtu per kWh × Fossil Fuel Cost ($/MMBtu) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Annual Fuel Usage in Year One* is the quantity of fuel consumed in Year One calculated by the performance model. *Fossil Fuel Cost* and *Escalation Rate* are from the System Costs page, and Inflation Rate is from the Financing page.

Note. When you specify fuel costs using an annual schedule instead of a single value, SAM does not apply the inflation rate or escalation rate to the values you specify for each year.

For the biomass power model, SAM calculates feedstock and coal costs using feedstock usage and price values from the Feedstock Costs page:

Biomass Feedstock Costs in Year n = Total Biomass Fuel Usage in Year One (dry tons/year) × Biomass Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Coal Feedstock Costs in Year n = Total Coal Fuel Usage in Year One (dry tons/year) × Coal Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where the fuel usage and fuel costs are from the Feedstock Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

Insurance expense

The insurance cost applies in Year One and later of the cash flow:

Insurance in Year n = Total Installed Costs ($) × Insurance (%) × (1 + Inflation Rate)^(n-1)

Where *Total Installed Costs* is the value from the System Costs page, and Insurance and Inflation Rate are specified on the Financing page.

Property tax net assessed value

The property assessed value is the value SAM uses as a basis to calculate the annual property tax payment:

Property Assessed Value in Year One = Assessed Value

Where *Assessed Value* is from the Financing page.

In Years 2 and later, the property assessed value is the Year One value adjusted by the assessed value decline value from the Financing page:

Property Assessed Value in Year n>1 = Assessed Value in Year One × [1 - Assessed Value Decline × (n-1)]

Where *Assessed Value Decline* is from the Financing page, expressed as a fraction instead of a percentage.

If the value of *1 - Assessed Value Decline* × *(n-1)* for a given year is equal to zero or less, then the *Property Assessed Value* in that year is zero.

Property tax expense

Property taxes apply in Year One and later of the cash flow:

Property Taxes in Year n = Property Assessed Value in Year n ($) × Property Tax (%)

Where *Property Assessed Value* is described above, and *Property Tax* is from the Financing page.

Annual Developer (Lessee LLC) Margin (Sale Leaseback only)

Annual Developer Margin in Year n = Developer Operating Margin × (1 + Developer Margin Escalation)^(n-1)

Where *Developer Operating Margin* and *Developer Margin Escalation* are from the Financing page.

Total operating expense

The total operating expense is the sum of expenses:

Total Operating Expense in Year n = O&M Fixed Expense + O&M Capacity-based Expense + O&M Production-based Expense + O&M Fuel Expense + Insurance Expense + Property Tax Expense

EBITDA

Earnings before interest, taxes, depreciation and amortization:

EBITDA = Total Revenue - Total Operating Expense

Where *Total Revenue* and *Total Operating Expense* are described above.

Project Cash Flow

The project cash flows include those from operating activities, investing activities, incentives, and issuance of equity. The pre-tax cash flow is the total project cash flow.

Project Cash Flows from Operating Activities

The cash flow from operating activities are the project earnings including interest on reserves and production-based incentives payments less interest paid on debt.

EBITDA

The earnings before interest, taxes, depreciation and amortization described above.

Interest on reserves

Interest on Reserves = Total Reserves ($) × Interest on Reserves (%)

Where *Total Reserves* is the sum of *Major Equipment Reserves*, *Working Capital Reserve*, and *Debt Service Reserves*, and *Interest on Reserves* is from the Financing page.

PBI (Federal, State, Utility, Other, Total)

These values represent income from production-based incentive payments, calculated as described below under Incentives.

Total project cash flow from operating activities

Total = EBITDA + Interest on Reserves + Total PBI - Interest

Project Cash Flows from Investing Activities

Purchase of property cost

The purchase of property cost applies only in Year Zero of the cash flow.

Purchase of Property Cost = Total Installed Cost + Debt Service Reserve + Working Capital Reserve

Where *Total Installed Cost* is from the System Costs page, and *Debt Service Reserve* and *Working Capital Reserve* are the total reserve amounts described below.

(Increase)/Decrease in working capital reserve account

The working capital reserve amount in Year Zero depends on the Months of Operating Costs from the Financing page and the Year One total operating expense:

Capital Reserve in Year Zero = Total Operating Expense in Year One ($) × Months of Operating Costs (months) ÷ 12 (months)

In Year One and later:

Capital Reserve in Year n>0 = Capital Reserve in Year n-1 ($) - Total Operating Expense in Year n ($) × Months of Operating Costs (months) ÷ 12 (months)

Where *Months of Operating Costs* is from the Financing page.

(Increase)/Decrease in major equipment reserve accounts

For each of the up to three major equipment reserve accounts that you specify on the Financing page, SAM calculates the annual amount required to ensure that sufficient funds are available in the replacement year to cover the replacement cost:

For example, in the example described below under Major Equipment Capital Spending, the annual increase in reserves is $530,682/year = $2,653,400 ÷ 5 years.

Increase in Major Equipment Reserve = Inflation Adjusted Replacement Cost in Replacement Year ($) ÷ Replacement Year (year)

The increase is shown in the cash flow as a negative value.

In the year that the replacement occurs (in this example, Year 5), the decrease in major equipment reserve account is $2,122,727 = $2,653,400 - $430,682.

Decrease in Major Equipment Reserve in Replacement Year = Inflation Adjusted Replacement Cost in Replacement Year - Increase in Major Equipment Reserve

The decrease is shown in the cash flow as a positive value.

Major equipment capital spending

For each of the up to three major equipment reserve accounts that you specify on the Financing page, the inflation-adjusted amount is reported in the year that you specify.

For example, if you specify a $2,500 (in Year One dollars) replacement cost with a 5 year replacement frequency, and an inflation rate of 1.5% on the Financing page, SAM reports a major equipment capital spending amounts in years 5, 10, 15 etc. For Year 5, the amount would be $2,653,400 = $2,500,000 × (1 + 0.015)^4.

In each year that the replacement occurs:

Capital Spending = - Replacement Cost (Year One $) × (1 + Inflation Rate)^(Replacement Year - 1)

The value is negative because it represents an expense or outflow.

Total project cash flow from investing activities

The total cash flow from investing activities is the sum of purchase property cost, reserve account deposits or withdrawals, and capital spending:

Total in Year Zero = Purchase of Property Cost + Major Equipment Reserve Account

Total in Year n>0 = Major Equipment Reserve Account + Major Equipment Capital Spending

Project Cash Flows from Financing Activities

Cash flows from financing activities include income from incentive payments, equity capital, and, for Single Owner and Leveraged Partnership Flip, debt capital.

Total IBI

The total investment-based incentive amount, described below.

Total CBI

The total capital-based incentive amount, described below.

Equity Capital

The equity capital invested in the project.

Issuance of Equity in Year Zero = Total Installed Cost + Financing Cost - (Debt Funding + Total IBI + Total CBI)

Where *Total Installed Cost* is the project capital cost from the System Costs page, *Financing Cost* is from the Metrics table, *Debt* (Single Owner and Leveraged Partnership Flip only) is the debt funding amount described below, and *Total IBI* and *Total CBI* are the investment-based incentive and capacity based incentive amounts described below.

Total project cash flow from financing activities

The total cash flow from financing activities is the sum of equity capital, incentive payments, and debt capital.

Total in Year Zero = Issuance of Equity + Total IBI + Total CBI + Debt Funding

Total in Year n>0 = Debt Repayment

Project total pre-tax cash flow

The pre-tax cash flow is the cash flow and accounts for operating expenses, investment earnings, and incentive payments.

Total Project Pre-tax Cash Flow in Year Zero = Issuance of Equity

Where *Issuance of Equity* is the equity investment in the project described above.

Total Project Pre-tax Cash Flow in Year n>0 = Total Cash Flows from Operating Activities + Total Cash Flows from Investing Activities + Total Incentives

Total Project Returns

The total project returns rows of the cash flow table show pre- and after-tax cash flows and returns from the project perspective. Returns from each partner's perspective appear under the Partners Returns heading and are described below.

Project pre-tax returns

Total project pre-tax returns

The total annual pre-tax cash flow is the cash flow and accounts for operating expenses, investment earnings, and incentive payments.

Pre-tax Cash Flow in Year Zero = Issuance of Equity

Where *Issuance of Equity* is the equity investment in the project described above.

Pre-tax Cash Flow in Year n>0 = Total Cash Flows from Operating Activities + Total Cash Flows *from Investing Activities + Total Incentives*

Project pre-tax cumulative IRR

SAM calculates the cumulative IRR for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the pre-tax cash flow described above.

Project pre-tax cumulative NPV

The cumulative net present value in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the pre-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Project after-tax returns

Cash

The pre-tax cash flow, described above.

Total project after-tax returns

The total annual after-tax cash flow is the sum of the pre-tax cash flow and tax credits less income tax payments:

After-tax Cash Flow in Year Zero = Pre-tax Cash Flow in Year Zero

After-tax Cash Flow in Year One = Pre-tax Cash Flow in Year One + Total ITC + Total PTC + Project Tax Benefit

After-tax Cash Flow in Year n>1 = Pre-tax Cash Flow in Year n + Total PTC + Project Tax Benefit

Project after-tax cumulative IRR

SAM calculates the cumulative IRR for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+IRR)^n} = 0$$

Where $C_{AfterTax,n}$ is the after-tax cash flow described above.

Project after-tax cumulative NPV

The cumulative net present value in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+d_{nominal})^n}$$

Where $C_{AfterTax,n}$ is the after-tax cash flow described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

Project LCOE

SAM reports quantities used in the LCOE calculation in the cash flow table for reference. For a description of the LCOE see Levelized Cost of Energy (LCOE).

Project PPA revenue

The total PPA revenue is the project's annual revenue from electricity sales, not accounting for salvage value:

Project PPA Revenue = Net Energy (kWh) × PPA Price (cents/kWh) ÷ 100 (cents/$)

Net Energy (kWh)

The total amount of electricity generated by the system in AC kilowatt-hours for each year. See description above

NPV of PPA revenue

The present value of the annual PPA revenue streams over the analysis period used as the numerator of the LCOE equation:

$$\text{NPV(Revenue)} = \sum_{n=0}^{N} \frac{R_{PPA,n}}{(1+d_{nominal})^n}$$

Where $R_{PPA,n}$ is the revenue from electricity sales-tax cash flow described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

NPV of net annual energy (nominal)

The LCOE calculation requires a discounted energy term in the denominator. The value discounted using the nominal discount rate is for the nominal LCOE equation.

$$\text{NPV(Energy Nominal)} = \sum_{n=0}^{N} \frac{Q_n}{(1+d_{nominal})^n}$$

Where Q_n is the annual energy value described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

Project Nominal LCOE

Project Nominal LCOE = NPV(Revenue) / NPV(Energy Nominal)

NPV of net annual energy (real)

The LCOE calculation requires a discounted energy term in the denominator. The value discounted using the real discount rate is for the real LCOE equation.

$$\text{NPV(Energy Real)} = \sum_{n=0}^{N} \frac{Q_n}{(1+d_{real})^n}$$

Where Q_n is the annual energy value described above, and d_{real} is the nominal discount rate from the Financing page.

Project Real LCOE

Project Real LCOE = NPV(Revenue) / NPV(Energy Real)

Partners Returns

The partners returns are the IRR, NPV, and taxes from each project partner's perspective.

Tax Investor

The tax investor cash flows represent the tax investor share of project cash flows.

Tax Investor Pre-Tax Returns

Total tax investor pre-tax returns

In Year Zero, the tax investor pre-tax cash flow is the portion of equity capital allocated to the tax investor:

Tax Investor Pre-Tax Cashflow in Year Zero = Tax Investor Share of Equity Contribution (%) × Issuance of Equity ($)

Where *Tax Investor Share of Equity Contribution* is from the Financing page.

For years before the flip target is reached:

Tax Investor Pre-Tax Cashflow in Year n>1 = Tax Investor Pre-flip Share of Project Cash (%) × Total Project Pre-tax Cash Flow ($)

For years after the flip target is reached:

Tax Investor Pre-Tax Cashflow in Year n>1 = Tax Investor Post-flip Share of Project Cash (%) × Total Project Pre-tax Cash Flow ($)

Where the pre- and post-flip share of project cash percentages are from the Financing page.

Tax investor cumulative IRR

Cumulative pre-tax IRR from the tax investor perspective for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the tax investor pre-tax cash flow described above.

For years when there is no mathematical solution, SAM reports a value of zero.

Tax investor cumulative NPV

Cumulative pre-tax net present value from the tax investor perspective in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1 + d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the tax investor pre-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Tax Investor After-Tax Returns

Tax investor cash (total pre-tax returns)

The tax investor pre-tax cash flow, described above.

ITC

The tax investor's share of the ITC amount applies to the tax investor's Year One cash flow:

Investment Tax Credit in Year One = Tax Investor Share of Equity Contribution (%) × (Federal ITC ($) + State ITC ($))

Where *Tax Investor Share of Equity Contribution* is from the Financing page, and *Federal ITC* and *State ITC* are described below.

PTC

The tax investor's share of the PTC applies in Years One and later of the tax investor's cash flow.

For years before the flip target is reached:

Production Tax Credit in Year n = Tax Investor Pre-flip Share of Project Cash (%) × (Federal PTC ($) + State PTC ($))

For years after the flip target is reached:

Production Tax Credit in Year n = Tax Investor Post-flip Share of Project Cash (%) × (Federal PTC ($) + State PTC ($))

Where the pre- and post-flip share of project cash values are from the Financing page, and *Federal PTC* and *State PTC* are described below.

Tax investor share of project tax

The tax investor's share of the project's tax payment or refund. A positive value indicates a tax refund, and a negative value indicates a tax payment.

For years before the flip target is reached:

Tax Investor Share of Project Tax in Year n = Tax Investor Pre-flip Share of Project Cash (%) × Project Tax Benefit/(Liability) ($)

For years after the flip target is reached:

Tax Investor Share of Project Tax in Year n = Tax Investor Post-flip Share of Project Cash (%) × Project Tax Benefit/(Liability) ($)

Where the pre- and post-flip share of project cash values are from the Financing page, and Project Tax Benefit/(Liability) is the tax amount owed.

Total tax investor after-tax returns

The tax investor's total after-tax cash flow.

Total = Cash + Investment Tax Credit + Production Tax Credit + Share of Project Tax Benefit/(Liability)

Tax investor cumulative IRR

Cumulative after-tax IRR from the tax investor perspective for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the tax investor after-tax cash flow described above.

For years when there is no mathematical solution, SAM reports a value of zero.

Tax investor cumulative NPV

Cumulative after-tax net present value from the tax investor perspective in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the tax investor after-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Tax investor maximum IRR

The greater of the Year One Cumulative IRR and the Year n Cumulative IRR.

Developer

The Developer cash flows represent the developer share of project cash flows.

Developer Pre-Tax Returns

Pre-tax development fee

A fee received by the developer.

Pre-tax Developer Development Fee in Year Zero = Development Fee

Where *Development Fee* is from the Financing page.

Total developer pre-tax returns

The pre-tax cash flow from the developer's perspective.

Developer Pre-tax Cash Flow in Year Zero = Equity Investment in Year Zero + Pre-tax Developer Development Fee

Developer Pre-tax Cash Flow in Year n>0 = Total Project After-tax Cash Flow - Tax Investor Pre-tax Cash Flow

Developer pre-tax cumulative IRR

Cumulative pre-tax IRR from the developer perspective for each year N of the cash flow. The cumulative IRR in a given Year N is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the tax investor after-tax cash flow described above.

For years when there is no mathematical solution, SAM reports a value of zero.

Developer pre-tax cumulative NPV

Cumulative pre-tax net present value from the developer perspective in a given Year N is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{PreTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the tax investor after-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Developer pre-tax IRR

The cumulative tax investor pre-tax IRR in the flip year defined on the Financing page.

For years when there is no mathematical solution, SAM reports a value of zero.

Developer pre-tax NPV

The cumulative tax investor pre-tax NPV in the flip year defined on the Financing page.

Developer After-Tax Returns

Equity Investment

The developer's share of the project equity capital.

Equity Investment in Year Zero = Total Project Equity Investment in Year Zero - Tax Investor Equity Investment in Year Zero

Development Fee

A fee received by the developer.

Development Fee in Year Zero = Development Fee

Where *Development Fee* is from the Financing page.

Cash

The pre-tax cash flow from the developer perspective.

Cash in Year Zero = Equity Investment + Development Fee

Cash in Year n>0 = Developer Pre-tax Cash Flow

ITC

The developer's share of the ITC amount applies to the tax developer's Year One cash flow:

Investment Tax Credit in Year One = Developer Share of Equity Contribution (%) × (Federal ITC ($) + State ITC ($))

Where *Developer Share of Equity Contribution* is from the Financing page, and *Federal ITC* and *State ITC* are described below.

PTC

The developer's share of the PTC applies in Years One and later of the developer's cash flow.

For years before the flip target is reached:

Production Tax Credit in Year n = Developer Pre-flip Share of Project Cash (%) × (Federal PTC ($) + State PTC ($))

For years after the flip target is reached:

Production Tax Credit in Year n = Developer Post-flip Share of Project Cash (%) × (Federal PTC ($) + State PTC ($))

Where the pre- and post-flip share of project cash values are from the Financing page, and *Federal PTC* and *State PTC* are described below.

Developer share of project tax

The developer's share of the project's tax payment or refund. A positive value indicates a tax refund, and a negative value indicates a tax payment.

For years before the flip target is reached:

Developer Share of Project Tax in Year n = Developer Pre-flip Share of Project Cash (%) × Project Tax Benefit/(Liability) ($)

For years after the flip target is reached:

Developer Share of Project Tax in Year n = Developer Post-flip Share of Project Cash (%) × Project Tax Benefit/(Liability) ($)

Where the pre- and post-flip share of project cash values are from the Financing page

Total developer after-tax returns

The developer's total after-tax cash flow.

Total Developer After-tax Returns = Cash + Investment Tax Credit + Production Tax Credit + Share of Project Tax Benefit/(Liability)

Developer after-tax cumulative IRR

Cumulative after-tax IRR from the developer perspective for each year n of the cash flow. The cumulative IRR in a given Year n is the discount rate that results in a value of zero for the present value of the discounted pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+IRR)^n} = 0$$

Where $C_{PreTax,n}$ is the developer after-tax cash flow described above.

For years when there is no mathematical solution, SAM reports a value of zero.

Developer after-tax cumulative NPV

Cumulative after-tax net present value from the developer perspective in a given Year n is the sum of the present values of the pre-tax cash flows up to Year N:

$$NPV = \sum_{n=0}^{N} \frac{C_{AfterTax,n}}{(1+d_{nominal})^n}$$

Where $C_{PreTax,n}$ is the developer after-tax cash flow described above, $d_{nominal}$ is the nominal discount rate from the Financing page.

Developer after-tax IRR

The cumulative developer pre-tax IRR in the flip year defined on the Financing page.

For years when there is no mathematical solution, SAM reports a value of zero.

Developer after-tax NPV

The cumulative developer pre-tax NPV in the flip year defined on the Financing page.

Incentives

The incentive cash flow rows show the value of cash incentives and tax credits, which are used to calculate cash flows described above.

IBI (Investment Based Incentives)

Each IBI (federal, state, utility, other) applies in Year Zero of the project cash flow.

Because you can specify each IBI on the Incentives page as either an amount or a percentage, SAM calculates the value of each IBI as the sum of two values:

IBI as Amount = Amount

IBI as Percentage = Total Installed Cost ($) × Percentage (%), up to Maximum

IBI in Year 0 = IBI as Amount + IBI as Percentage

Where *Amount*, *Percentage* and *Maximum* are the values that you specify on the Incentives page, and *Total Installed Cost* is from the System Costs page.

Total IBI is the sum of the four IBI values (federal, state, utility, other).

Note. The IBI amount reduces the after tax cost flow in Year Zero, and the debt balance in Year One. This is because SAM assumes that debt payments begin in Year One, when the project is generating or saving electricity.

CBI (Capacity Based Incentives))

Each CBI (federal, state, utility, other) applies in Year Zero of the project cash flow:

CBI in Year 0 = System Capacity (W) × Amount ($/W), up to Maximum

Where System Capacity is the rated capacity of the system, and *Amount* and *Maximum* are the values you specify on the Incentives page.

Total CBI is the sum of the four CBI values (federal, state, utility, other).

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 30. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array

High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

PBI (Performance Based Incentive)

Each PBI (federal, state, utility, other) applies in Years One and later of the project cash flow, up to the number of years you specify:

PBI in Year n = Amount ($/kWh) × Energy in Year n (kWh) × (1 + Escalation)^(n-1), up to Term

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in Energy row of the cash flow table (described above).

Note. If you use an annual schedule to specify year-by-year PBI amounts, SAM ignores the escalation rate.

Total PBI is the sum of the four PBI amounts (federal, state, utility, other).

Important Note! If you specify a PBI amount on the Cash Incentives page, be sure to also specify the incentive term. If you specify a term of zero, the incentive will not appear in the cash flow table.

PTC (Production Tax Credit)

The state and federal PTC each apply in Year One and later of the project cash flow, up to the number of years you specify:

PTC in Year n = Amount ($/kWh) × (1 + Escalation)^(n-1) × Energy in Year n (kWh)

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in the Energy row of the cash flow table (described above).

SAM rounds the product *Amount ($/kWh) × (1 + Escalation)^(n-1)* to the nearest multiple of 0.1 cent as described in Notice 2010-37 of IRS Bulletin 2010-18.

Note. If you specify year-by-year PTC rates on the Incentives page using an Annual Schedule instead of a single value, SAM ignores the PTC escalation rate.

ITC (Investment Tax Credit)

The state and federal ITC each apply only in Year One of the project cash flow. For ITCs that you specify as a fixed amount:

ITC in Year One = Amount

Where *Amount* is the value you specify in the Incentives page.

For ITCs that you specify as a percentage of total installed costs:

ITC in Year One = (Total Installed Cost ($) - ITC Basis Reduction ($)) × Percentage (%), up to Maximum

Where *Total Installed Cost* is from the System Costs page, and *Percentage* and *Maximum* are the values you specify on the Incentives page.

ITC Basis Reduction applies only to the Commercial and Utility financing options, and depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked boxes under **Reduces Depreciation and ITC Bases**. For each IBI or CBI with a check mark, SAM subtracts the incentive amount from the total installed cost to calculate the ITC.

ITC Basis Reduction = IBI + CBI

Where *IBI* and *CBI* are the incentives that you have specified reduce the ITC basis on the Incentives page.

Debt

The debt amounts depend on the following inputs from the Financing page:

- Debt Rate
- DSCR

Funding

The funding amount applies in Year Zero, and is the size of debt assuming the constant DSCR specified on the Financing page:

$$\text{Funding} = \sum_{n=1}^{N} \frac{\frac{CAFDS_n}{(1 + Debt\ Rate)^n}}{DSCR}$$

Where $CAFDS_n$ is the cash available for debt service in Year n, and *Debt Rate* and *DSCR* are from the Financing page.

CAFDS in Year n= EBIDTA in Year n - Sum of Major Equipment Replacement Reserves in Year n

Where EBIDTA and Major Equipment Reserves are described above and below, respectively.

Repayment

Repayment applies in Year One and later, and represents annual debt payments.

Repayment in Year n = - Principal in Year n

Where *Principal in Year n* is described below.

Ending Balance

The ending balance applies in Year Zero and later:

Ending Balance in Year Zero = Funding

Where *Funding* is described above.

Ending Balance in Year n = Ending Balance in Year n-1 + Repayment in Year n

Where *Repayment* is described above.

Principal

The principal applies in Year One and later:

Principal in Year n = Total P&I in Year n - Interest in Year n

Where *Total P&I* and *Interest* are described below.

Interest

The interest applies in Year One and later:

Interest in Year n = Ending Balance in Year n × Debt Rate

Where *Ending Balance* is described above, and *Debt Rate* is from the Financing page.

Total P&I

The total principal and interest applies in Year One and later:

Total P&I in Year n = CAFDS in Year n ÷ DSCR

Where *CAFDS in Year n* is described above (under Funding), and *DSCR* is from the Financing page.

Reserve Accounts

Reserve accounts include debt service, working capital reserve, and major equipment replacement reserves. The reserve account amounts depend on the following inputs from the Financing page:

- Inflation Rate
- Debt Service Reserve Account (months P&I)
- Working Capital Reserve Months of Operating Costs
- Major Equipment Replacement Reserve Account [1-3] Frequency (years)
- Major Equipment Replacement [1-3] (Year 1 $)

Lease Payment Reserve (Sale Leaseback only)

Lease Payment Reserve = Tax Investor (Lessor) Required Lease Payment Reserve (months) ÷ 12 × Total Developer Pre-tax Cash Flow from Operating Activities in Year n+1

Debt Service Reserve

The debt service reserve applies in Year Zero and later:

Debt Service Reserve = Debt Service Reserve Account (months P&I) ÷ 12 × Total P&I in Year n+1

Where *Debt Service Reserve Account (months P&I)* is from the Financing page, and *Total P&I in Year n+1* is described under Debt above.

Working Capital Reserve

Working capital reserve applies in Year Zero and later:

Working Capital Reserve = Months of Operating Costs × Operating Expenses in Year n+1

Where *Months of Operating Costs* is from the Financing page, and *Operating Expenses in Year n+1* is described above.

Major Equipment Replacement Reserves

You can specify up to three major equipment reserve accounts on the Financing page. For each account, the amount applies in Year One and later of the cash flow:

Major Equipment Reserve in Year n = Major Equipment Reserve in Year n-1 + Funding + Release of Funds

Where Major Equipment Reserve in Year Zero = 0, and:

Funding = Release of Funds in Year of Next Replacement ÷ Replacement Frequency

Release of Funds in Year of Next Replacement = - Replacement Cost in Year One $ × (1 + Inflation Rate)^(n-1)

Where *Replacement Frequency*, *Replacement Cost in Year One $*, and *Inflation Rate* are from the Financing page

Depreciation and ITC Tables

The federal and state Depreciation and ITC tables show the depreciable basis calculation for each of the up to seven depreciation classes for federal and state tax purposes:

- The total depreciable amount includes the total installed cost, development fee, equity closing cost, debt service reserve, working capital reserve, and for the Sale Leaseback financing option, the lease payment reserve.
- The depreciation class allocations on the Financing page determine how the depreciable basis is allocated to the different depreciation classes (MACRS 5-yr, Straight Line, etc.).
- For each state and federal IBI and CBI with **Reduces Depreciation and ITC Bases** checked on the Incentives page, the full incentive amount reduces the depreciable basis.
- For each state and federal ITC with **Reduces Depreciation Basis** checked on the Incentives page, 50% of the tax credit amount reduces the depreciable basis.
- For each depreciation class with a checked box under **Bonus Depreciation** on the Financing page, the depreciable basis is the product of the bonus depreciation percentage and the adjusted depreciable basis. (The adjusted depreciable basis is the total depreciable after incentives and tax credit adjustments.)
- For state and federal taxes, depreciation for major equipment replacement reserves uses the class specified on the Financing page.

The depreciation amounts depend on the total installed cost from the System Costs page, and the following inputs from other pages.

From the Financing page:

- Development Fee
- Debt Closing Costs
- Debt Closing Fee
- Equity Closing Cost
- Construction Financing
- Other Financing Cost

From the Incentives page:

- State ITC as Percentage
- State ITC Maximum
- State ITC as Amount
- Federal ITC as Percentage
- Federal ITC Maximum
- Federal ITC as Amount
- Status of **Reduces Depreciation Basis** check boxes
- The amounts and percentages of any incentive with **Reduces Depreciation and ITC Bases** checked

From the Depreciation page:

- Allocations for each depreciation class
- Bonus depreciation amounts and applicable depreciation classes
- ITC qualification status of depreciation classes

The depreciation amounts also depend on the following cash flow values:

- Debt service reserve
- Working capital reserve
- IBI (only for incentives shown to reduce depreciation basis on Incentives page)
- CBI (only for incentives shown to reduce depreciation basis on Incentives page)
- Debt funding
- For state depreciation, the federal ITC basis disallowance amounts for each depreciation class
- For federal depreciation, the state ITC basis disallowance amounts for each depreciation class

Gross Depreciable Basis with IBI and CBI Reductions Before ITC Reductions

For each depreciable class, the depreciable basis before reduction by the ITC is the gross depreciable basis less IBI and CBI amounts for incentives on the Cash Incentives page with **Reduces Depreciation and ITC Bases** checked.

> **Note.** The IBI and CBI reduce the depreciation basis for state taxes only when **State** under **Reduces Depreciation and ITC Bases** is checked. Similarly, the IBI and CBI reduce the depreciation basis for federal taxes only when **Federal** under **Reduces Depreciation and ITC Bases**.

% of Total Depreciable Basis

The normalized allocation for each depreciation class allocation:

% of Total Depreciable Basis = Allocation ÷ Sum of Allocations

Where *Allocation* is the percentage for the given depreciable class, and *Sum of Allocations* is the sum of all allocations from the Financing page.

Gross Amount Allocated

The gross depreciable basis before reductions for each depreciation class:

Gross Amount Allocated = % of Total Depreciable Basis × Total Depreciable Amount

Where % of Total Depreciable Basis is described above, and

Total Depreciable Amount = Total Installed Cost + Development Fee + Equity Closing Cost + Debt Closing Costs + Debt Closing Fee × Funding + Debt Service Reserve + Working Capital

Reserve + Lease Payment Reserve

Where *Total Installed Cost* is from the System Costs page; *Development Fee*, *Equity Closing Cost*, *Debt Closing Costs*, and *Debt Closing Fee* are from the Financing page; and *Debt Service Reserve*, *Working Capital Reserve* and *Lease Payment Reserve* (Sale Leaseback financing option only) are other values in the cash flow described above

Reduction: IBI

The reduction in depreciation basis from IBI payments:

Reduction IBI = Total IBI that Reduce Depreciation × *% of Total Depreciable Basis*

Where *Total IBI that Reduce Depreciation* is the sum of IBI values in the cash flow for incentives with **Reduces Depreciation and ITC Bases** checked on the Incentives page. For the state depreciation table, **State** must be checked for the incentive to reduce the state depreciation basis. For the federal depreciation table, **Federal** must be checked. *% of Total Depreciable Basis* is the allocation for the depreciation class described above.

Reduction: CBI

The reduction in depreciation basis from CBI payments:

Reduction CBI = Total CBI that Reduce Depreciation × *% of Total Depreciable Basis*

Where *Total CBI that Reduce Depreciation* is the sum of CBI values in the cash flow for incentives with **Reduces Depreciation and ITC Bases** checked on the Incentives page. For the state depreciation table, **State** must be checked for the incentive to reduce the state depreciation basis. For the federal depreciation table, **Federal** must be checked. *% of Total Depreciable Basis* is the allocation for the depreciation class described above.

Depreciable Basis Prior to ITC

The depreciable basis reduced by CBI and IBI amounts:

Depreciable Basis Prior to ITC = Gross Amount Allocated - Reduction: IBI - Reduction: CBI

ITC Reduction

For each ITC on the Incentives page with **Reduces Depreciation Basis** checked, 50% of the ITC amount can be included in the depreciable basis for each depreciable class with **ITC Qualification** checked on the Depreciation page. SAM calculates the ITC reduction amount for ITCs that you specify on the Incentives page a percentage of the total installed costs with a maximum amount, and ITCs that you specify as a fixed amount.

Note. The ITC reduces the depreciation basis for state taxes only when **State** under **Reduces Depreciation Basis** is checked on the Incentives page, and when **State** is checked under **ITC Qualification** for the depreciation class on the Depreciation page. Similarly, the ITC reduces the depreciation basis for federal taxes only when **Federal** is checked under **Reduces Depreciation Basis** and under **ITC Qualification** for the depreciation class.

For each ITC specified as a percentage and maximum on the Incentives page, the *ITC Basis Disallowance* is the amount that may be available for depreciation basis reduction. (The ITC Reduction amounts are the amounts actually available.):

ITC Qualifying Costs

For depreciation classes with **ITC Qualification** checked on the Depreciation page:

ITC Qualifying Costs = Depreciable Basis Prior to ITC

% of ITC Qualifying Costs

For each depreciable class:

% of ITC Qualifying Costs = ITC Qualifying Costs ÷ Total Depreciable Basis Prior to ITC

Where *Total Depreciable Basis Prior* to ITC is the sum of *Depreciable Basis Prior to ITC* for all depreciable classes.

ITC Amount

ITC Amount = % of ITC Qualifying Costs × ITC Qualifying Costs

ITC Basis Disallowance

The ITC depreciation basis disallowance is 50% of the ITC amount:

ITC Basis Disallowance = ITC Amount × 0.5

For each ITC specified as a fixed amount on the Incentives page, the ITC Basis Disallowance is the amount that may be available for depreciation basis reduction. (The ITC Reduction amounts are the amounts actually available.):

ITC Amount

For each depreciable class, the Total ITC Amount is the amount that may be available for depreciation reduction:

ITC Amount = Total ITC Amount × % of ITC Qualifying Costs

Where, for the state depreciation table, *Total ITC Amount* is the state ITC amount from the Incentives page. For the federal depreciation table, *Total ITC Amount* is the federal ITC amount from the Incentives page.

ITC Basis Disallowance

The ITC depreciation basis disallowance is 50% of the ITC amount:

ITC Basis Disallowance = ITC Amount × 0.5

The depreciable basis after ITC reduction is the sum of the total ITC basis disallowance values for the ITCs with **Reduces Depreciation Basis** checked on the Incentives pages.

ITC Reduction: State

ITC Reduction: State = ITC Basis Disallowance (ITC as %) + ITC Basis Disallowance (ITC as Fixed Amount)

Where the ITC basis disallowance values are from the state depreciation table for the ITCs that reduce depreciation basis.

ITC Reduction: Federal

ITC Reduction: Federal = ITC Basis Disallowance (ITC as %) + ITC Basis Disallowance (ITC as Fixed Amount)

Where the ITC basis disallowance values are from the federal depreciation table for the ITCs that reduce depreciation basis.

Depreciable Basis after ITC Reduction

Depreciable Basis after ITC Reduction = Depreciable Basis Prior to ITC - ITC Reduction:State - ITC Reduction:Federal

Bonus Depreciation

For each depreciation class that qualifies for bonus depreciation as indicated by the check boxes under Bonus Depreciation on the Depreciation page, bonus depreciation percentage applies to the depreciable basis.

Note. The bonus depreciation percentage applies to the depreciation basis for state taxes only when **State** under **Bonus Depreciation** is checked. Similarly, the bonus depreciation percentage applies for federal taxes only when **Federal** under **Reduces Depreciation Basis** is checked.

First Year Bonus Depreciation

For each depreciation class with **Bonus Depreciation** checked on the Depreciation page:

First Year Bonus Depreciation = Depreciable Basis after ITC Reduction × Bonus Depreciation Percentage

Where Bonus Depreciation Percentage is from the Depreciation page: The state bonus percentage applies to the state depreciation table, and the federal percentage applies to the federal depreciation table.

Depreciable Basis

The depreciable basis after IBI, CBI, ITC and bonus depreciation reduction is the basis to which the depreciation percentages defined by the depreciation class apply.

Depreciable Basis after Bonus Reduction = Depreciable Basis after ITC Reduction - First Year Bonus Depreciation

The following table shows the depreciation percentage by year for each depreciation class. For each depreciation class, the percentage is applied to the depreciable basis amount for the given year in the cash flow:

Years 1-10	1	2	3	4	5	6	7	8	9	10
5-yr MACRS	20.0	32.0	19.2	11.5	11.5	5.8				
15-yr MACRS	5.0	9.5	8.6	7.7	6.9	6.2	5.9	5.9	5.9	5.9
5-yr SL	10.0	20.0	20.0	20.0	20.0	10.0				
15-yr SL	3.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
20-yr SL	2.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	1.3	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 11-20	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
15-yr MACRS	5.9	5.9	5.9	5.9	5.9	3.0				
15-yr SL	6.7	6.7	6.7	6.7	6.7	3.3				
20-yr SL	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 21-30	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
20-yr SL	2.5									
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 31-40	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	1.3

20.6 Sale Leaseback

This topic describes the cash flow table generated by the financial model for the Utility Sale Leaseback financing option. See Financing Overview for details.

Metric	Base
Net Annual Energy	6,857 kWh
LCOE Nominal	19.70 ¢/kWh
LCOE Real	15.68 ¢/kWh
First Year Revenue without System	$ 0.00
First Year Revenue with System	$ 822.88
First Year Net Revenue	$ 822.88
After-tax NPV	$ -2,929.81
Payback Period	27.4309 years
Capacity Factor	20.2 %
First year kWhac/kWdc	1,770
System Performance Factor	0.79
Total Land Area	0.01 acres

For descriptions of the variables in the Metrics table, see:

- Financial Metrics
- Performance Metrics

SAM offers three options for exporting the cash flow table:

- **Copy to clipboard** copies the table to your clipboard. You can paste the entire table into a word processing document, spreadsheet, presentation or other software.
- **Save as CSV** saves the table in a comma-delimited text file that you can open in a spreadsheet program or text editor.
- **Send to Excel (Windows only)** creates a new Excel file that contains the data from the cash flow table in an Excel file, but no formulas.
- **Send to Excel with Equations (Windows only)** exports the cash flow data to an existing Excel workbook that contains formulas to illustrate how SAM's internal cash flow calculations work. The workbooks are in the *\exelib\spreadsheets\equations* folder of your SAM installation folder.

Notes.

SAM makes cash flow calculations internally during simulations. It does not use Excel to make the calculations. The two **Send to Excel** options are to help you analyze the cash flow data and understand how SAM's internal calculations work.

You can also display cash flow data by building a Table. This option allows you to choose the rows to include in the table, and also makes it possible to show cash flow results from a parametric analysis.

Partial Income Statement: Project

The partial income statement rows show the annual revenue to the project as a whole. For projects with multiple partners, this revenue is the total revenue, before allocations to the different partners.

Net Energy (kWh)

For systems that generate electricity, *Energy* is the total amount of electricity generated by the system in AC kilowatt-hours for each year.

For solar water heating systems, *Energy* is the amount of electricity saved by the solar water heating system in AC kilowatt-hours for each year.

The performance model runs hourly or sub-hourly simulations to calculate the total annual energy value, which the financial model considers to be energy value for in Year One of the cash flow. SAM adjusts that value using the factors you specify on the Performance Adjustment page to account for expected system downtime for maintenance, and degradation of system performance over time.

Note. The annual energy value reported for Year one in the cash flow is not equal to the sum of the hourly energy values because the hourly values do not account for the **Percent of annual output** factor from the Performance Adjustment page.

For Year One, *Energy* is the value is calculated by the performance model:

Energy in Year One = Sum of Simulation Values x Percent of Annual Output

Where *Sum of Simulation Values* is the system's total annual electrical output (or energy saved) equal to the sum of the values calculated by the performance model (8,760 values for hourly simulations), and *Percent of Annual Output* is from the Performance Adjustment page.

Notes.

If you specify *Availability* on the Performance Adjustment page using the annual schedule option, SAM applies the value you specified for each year to the Year One Energy value:
Energy in Year n>1 = Energy in Year One × Availability in Year n

The Geothermal Power performance model runs simulations for each year of the analysis period rather than only for Year One. For the Geothermal Power model:
Energy in Year n = Energy in Year n × Availability in Year n

For Years 2 and later:

Energy in Year n>1 = Energy in Year n-1 × (1 - Year-to-Year Decline in Output)

Where *Energy in Year n-1* is the previous year's energy value and *Year-to-Year Decline* is from the Performance Adjustment page.

Note. If you specified **Year-to-year decline in output** on the Performance Adjustment page using the annual schedule option, SAM applies the value as follows (after applying the appropriate availability factor to calculate the Year One energy value):

Energy in Year n>1 = Energy in Year n × (1 - Year-to-Year Decline in Output in Year n)

PPA price (cents/kWh)

The PPA price in Year One is either the value you specify on the Financing page, or the value calculated by SAM to meet the IRR target you specify on the Financing page. The PPA price in Year One is the PPA price:

PPA Price in Year One = Adjusted PPA Price

For analyses that do not involve time-dependent pricing, *Adjusted PPA Price* is equal to the PPA Price reported on the Metrics table.

For analyses that do involve time-dependent pricing, for each hour of the year, SAM multiplies the PPA price shown in the Metrics table (equivalent to the bid price) by the TOD factor for that hour to calculate a set of hourly energy prices for Year one. The *Adjusted PPA Price* is the average of the 8,760 hourly values.

Notes.

When you choose **Specify PPA Price** for **Solution Mode** on the Financing page, the PPA Price in the Metrics table is equal to the price you specify. When you choose **Specify IRR Target**, SAM calculates the PPA price required to meet the IRR target that you specify.

The TOD factors are on the Thermal Energy Storage page for CSP systems (parabolic trough, power tower, linear Fresnel, generic solar system), and on the Time of Delivery Factors page for photovoltaic and other systems.

To remove time-dependent pricing from your analysis, set the TOD factor for each of the 9 periods to one.Where Adjusted PPA Price is either the value you specify on the Financing page, or a value calculated to cover project costs based on the target IRR you specify on the Financing page, adjusted by the time-of-delivery (TOD) factors.

In Years Two and later:

PPA Price in Year n>1 = PPA Price in Year n-1 × (1 + PPA Escalation Rate)^(n-1)

Where *PPA Escalation Rate* is from the Financing page.

Note. SAM uses the PPA Price to calculate the levelized cost of energy.

Total PPA revenue

The total PPA revenue is the project's annual revenue from electricity sales, not accounting for salvage value:

Total PPA Revenue = Net Energy (kWh) × PPA Price (cents/kWh) × 0.01 ($/cents)

Salvage value

SAM calculates the net salvage value using the percentage you specify on the Financing page and the total installed cost from the System Costs page. The salvage value applies in the final year of the project cash flow.

For example, if you specify a 10% salvage value for a project with a 30-year analysis period, and total installed cost of $1 million, SAM includes income in Year 30 of *$100,000 = $1,000,000 × 0.10*.

SAM adds the salvage value as income (a negative value) to the operating expenses in the cash flow in the final year of the analysis period. The salvage value therefore reduces the operating expenses in the final year of the analysis period

For residential projects, the salvage value has no effect on federal and state income tax because operating expenses are not taxable.

For commercial projects, because the salvage value reduces the operating expenses in the final year of the analysis period, it increases the federal and state income tax payment because operating expenses are deductible from federal and state income tax.

Total revenue

The projects annual revenue, accounting for salvage value.

Total Revenue = Total PPA Revenue + Salvage Value

Because Salvage Value is zero for all years except the last year of the analysis period, the Total Revenue and Total PPA Revenue are the same for all years except for the last year.

For the Single Owner and Leveraged Partnership Flip financing options (both of which include debt), total revenue may also include production-based incentive (PBI) amounts. For each PBI amount that you check on the Financing page under **Debt Service**, **Production Based Incentives (PBI) Available for Debt Service**, SAM displays a row for the PBI above the Total Revenue row, and includes the amount in the Total Revenue amount:

Total Revenue = Total PPA Revenue + Salvage Value + PBI

Expenses

O&M Fixed expense

O&M Fixed Expense in Year n = Fixed Annual Cost ($) × (1 + Inflation Rate + Escalation Rate) ^ n-1

Where *Fixed Annual Cost* is from the System Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

O&M Capacity-based expense

O&M Capacity-based Expense in Year n = Fixed Cost by Capacity ($/kW-yr) × System Rated Capacity × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Fixed Cost by Capacity* is from the System Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 31. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment

Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

O&M Production-based expense

*O&M Production-based Expense in Year n = Variable Cost by Generation ($/MWh) × Net Energy in Year n (MWh) * (1 + Inflation Rate + Escalation Rate)^(n-1)*

Where *Variable Cost by Generation* is from the System Costs page, *Net Energy* is described above, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

O&M Fuel expense

The following performance models include a fuel cost calculation:

- Parabolic trough (physical or empirical) with fossil backup
- Power tower with fossil backup
- Generic solar system with fossil backup
- Generic system for the primary fuel cost
- Biomass Power for biomass and supplementary coal feedstock costs

Note. For the CSP systems listed above, SAM only considers the system to have a fossil-fired backup boiler when the fossil fill fraction variable on the Thermal Storage page is greater than zero.

For solar and generic systems listed above that consume a fuel, Fuel O&M is the annual fuel cost:

Fuel O&M in Year n = Annual Fuel Usage in Year One (kWh) × 0.003413 MMBtu per kWh × Fossil Fuel Cost ($/MMBtu) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where *Annual Fuel Usage in Year One* is the quantity of fuel consumed in Year One calculated by the performance model. *Fossil Fuel Cost* and *Escalation Rate* are from the System Costs page, and Inflation Rate is from the Financing page.

Note. When you specify fuel costs using an annual schedule instead of a single value, SAM does not apply the inflation rate or escalation rate to the values you specify for each year.

For the biomass power model, SAM calculates feedstock and coal costs using feedstock usage and price values from the Feedstock Costs page:

Biomass Feedstock Costs in Year n = Total Biomass Fuel Usage in Year One (dry tons/year) × Biomass Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Coal Feedstock Costs in Year n = Total Coal Fuel Usage in Year One (dry tons/year) × Coal Fuel Cost ($/dry ton) × (1 + Inflation Rate + Escalation Rate)^(n-1)

Where the fuel usage and fuel costs are from the Feedstock Costs page, and *Inflation Rate* and *Escalation Rate* are from the Financing page.

Insurance expense

The insurance cost applies in Year One and later of the cash flow:

Insurance in Year n = Total Installed Costs ($) × Insurance (%) × (1 + Inflation Rate)^(n-1)

Where *Total Installed Costs* is the value from the System Costs page, and Insurance and Inflation Rate are specified on the Financing page.

Property tax net assessed value

The property assessed value is the value SAM uses as a basis to calculate the annual property tax payment:

Property Assessed Value in Year One = Assessed Value

Where *Assessed Value* is from the Financing page.

In Years 2 and later, the property assessed value is the Year One value adjusted by the assessed value decline value from the Financing page:

Property Assessed Value in Year n>1 = Assessed Value in Year One × [1 - Assessed Value Decline × (n-1)]

Where *Assessed Value Decline* is from the Financing page, expressed as a fraction instead of a percentage.

If the value of *1 - Assessed Value Decline × (n-1)* for a given year is equal to zero or less, then the *Property Assessed Value* in that year is zero.

Property tax expense

Property taxes apply in Year One and later of the cash flow:

Property Taxes in Year n = Property Assessed Value in Year n ($) × Property Tax (%)

Where *Property Assessed Value* is described above, and *Property Tax* is from the Financing page.

Annual Developer (Lessee LLC) Margin (Sale Leaseback only)

Annual Developer Margin in Year n = Developer Operating Margin × (1 + Developer Margin Escalation)^(n-1)

Where *Developer Operating Margin* and *Developer Margin Escalation* are from the Financing page.

Total operating expense

The total operating expense is the sum of expenses:

Total Operating Expense in Year n = O&M Fixed Expense + O&M Capacity-based Expense + O&M Production-based Expense + O&M Fuel Expense + Insurance Expense + Property Tax Expense

Operating Margin Not Including Lease Payment

Operating Margin Not Including Lease Payment = Total Revenue - Total Operating Expense

Cash Flow: Developer (Lessee LLC)

Cash Flows from Operating Activities

The developer's cash flow from operating activities includes revenue less operating expenses plus interest earned on reserves.

Operating Margin Not Including Lease Payment

See above.

Plus Interest Earned

Interest earned on reserves

Plus Interest Earned = Total Reserves in Year n × Interest on Reserves

Where *Interest on Reserves* is from the Financing page and *Total Reserves in Year n* is the sum of capital reserve and the up to three major equipment reserve ending balances in Year n:

Total Reserves = Working Capital Reserve Ending Balance + Total Major Equipment Reserve Ending Balance

Total

The total cash flow from operating reserves is the sum of operating margin and interest earned on reserves:

Total in Year n = Operating Margin Not Including Lease Payment + Plus Interest Earned

Developer Cash Flows from Investing Activities

The developer's cash flow from investing activities occurs in Year Zero, except for the salvage value adjustment which is in the final year of the cash flow.

Sale of Property

Sale of Property in Year Zero = Total Construction Financing Cost + Development Fee + Equity Closing Cost + Other Financing Cost + Total Installed Costs

Where *Total Construction Financing Cost*, *Development Fee*, *Equity Closing Cost*, and *Other Financing Cost* are from the Financing page, and *Total Installed Costs* is from the System Costs page.

Purchase of Plant

Purchase of Plant in Year Zero = Total Installed Cost - Equity Closing Cost - Total Construction Financing

Where *Total Construction Financing Cost*, and *Equity Closing Cost* are from the Financing page, and *Total Installed Costs* is from the System Costs page.

Distribution of Development Fee

Distribution of Development Fee in Year 0 = Development Fee

Where Development fee is from the Financing page.

Adjustment for Salvage Value

Adjustment for Salvage value in Final Year = - Salvage Value

Where *Salvage Value* is described above under Partial Income Statement: Project.

(Increase)/Decrease in working capital reserve account

The working capital reserve amount in Year Zero depends on the Months of Operating Costs from the Financing page and the Year One total operating expense:

Capital Reserve in Year Zero = Total Operating Expense in Year One ($) × Months of Operating Costs (months) ÷ 12 (months)

In Year One and later:

Capital Reserve in Year n>0 = Capital Reserve in Year n-1 ($) - Total Operating Expense in Year n ($) × Months of Operating Costs (months) ÷ 12 (months)

Where *Months of Operating Costs* is from the Financing page.

(Increase)/Decrease in major equipment reserve accounts

For each of the up to three major equipment reserve accounts that you specify on the Financing page, SAM calculates the annual amount required to ensure that sufficient funds are available in the replacement year to cover the replacement cost:

For example, in the example described below under Major Equipment Capital Spending, the annual increase in reserves is $530,682/year = $2,653,400 ÷ 5 years.

Increase in Major Equipment Reserve = Inflation Adjusted Replacement Cost in Replacement Year ($) ÷ Replacement Year (year)

The increase is shown in the cash flow as a negative value.

In the year that the replacement occurs (in this example, Year 5), the decrease in major equipment reserve account is $2,122,727 = $2,653,400 - $430,682.

Decrease in Major Equipment Reserve in Replacement Year = Inflation Adjusted Replacement Cost in Replacement Year - Increase in Major Equipment Reserve

The decrease is shown in the cash flow as a positive value.

(Increase)/Decrease in reserve accounts

Increase in reserve accounts = Lease Payment Reserve + Working Capital Reserve + Total Major Equipment Reserves

Where the reserve amounts are described below under Reserve Accounts.

Major equipment capital spending

For each of the up to three major equipment reserve accounts that you specify on the Financing page, the inflation-adjusted amount is reported in the year that you specify.

For example, if you specify a $2,500 (in Year One dollars) replacement cost with a 5 year replacement frequency, and an inflation rate of 1.5% on the Financing page, SAM reports a major equipment capital spending amounts in years 5, 10, 15 etc. For Year 5, the amount would be $2,653,400 = $2,500,000 × (1 + 0.015)^4.

In each year that the replacement occurs:

Capital Spending = - Replacement Cost (Year One $) × (1 + Inflation Rate)^(Replacement Year - 1)

The value is negative because it represents an expense or outflow.

Total

The total developer cash flows from investing activities is the sum of purchase property cost, reserve account deposits or withdrawals, and capital spending:

Total in Year Zero = Sale of Property + Purchase of Plant + Distribution and Development Fee + Working Capital Reserve Account + Lease Payment Reserve + Major Equipment Reserve Account

Total in Year n>0 = Major Equipment Reserve Account + Major Equipment Capital Spending

Developer Cash Flows from Financing Activities

Developer Equity in Lessee LLC (funding of reserve accounts)

Total

Pre-tax cash flow including release of reserves

Adjustment for release of reserves

Developer Pre-tax operating cash flow (effective lease payment)

Cash Flow: Tax Investor (Lessor)

Tax Investor Cash Flows from Operating Activities

Lease Payment

Total

Tax Investor Cash Flows from Investing Activities

Purchase of Property

Pre-Tax Salvage Value

Total

Tax Investor Cash Flows from Financing Activities

Issuance of equity

IBI

CBI

Total

Tax Investor Pre-tax Cash Flow

LCOE

SAM reports quantities used in the LCOE calculation in the cash flow table for reference. For a description of the LCOE see Levelized Cost of Energy (LCOE).

Total PPA revenue

The total PPA revenue is the project's annual revenue from electricity sales, not accounting for salvage value:

Total PPA Revenue = Net Energy (kWh) × PPA Price (cents/kWh) ÷ 100 (cents/$)

Net Energy (kWh)

The total amount of electricity generated by the system in AC kilowatt-hours for each year. See description above

NPV of PPA revenue

The present value of the annual PPA revenue streams over the analysis period used as the numerator of the LCOE equation:

$$\text{NPV(Revenue)} = \sum_{n=0}^{N} \frac{R_{PPA,n}}{(1 + d_{nominal})^n}$$

Where $R_{PPA,n}$ is the revenue from electricity sales-tax cash flow described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

NPV of net annual energy (nominal)

The LCOE calculation requires a discounted energy term in the denominator. The value discounted using the nominal discount rate is for the nominal LCOE equation.

$$\text{NPV(Energy Nominal)} = \sum_{n=0}^{N} \frac{Q_n}{(1 + d_{nominal})^n}$$

Where Q_n is the annual energy value described above, and $d_{nominal}$ is the nominal discount rate from the Financing page.

Nominal LCOE

Nominal LCOE = NPV (Revenue) / NPV(Energy Nominal)

NPV of net annual energy (real)

The LCOE calculation requires a discounted energy term in the denominator. The value discounted using the real discount rate is for the real LCOE equation.

$$\text{NPV(Energy Real)} = \sum_{n=0}^{N} \frac{Q_n}{(1 + d_{real})^n}$$

Where Q_n is the annual energy value described above, and d_{real} is the nominal discount rate from the Financing page.

Real LCOE

Real LCOE = NPV (Revenue) / NPV(Energy Real)

Party Returns

Tax Investor (Lessor) Pre-tax

Purchase price of asset

IBI income

CBI income

Pre-tax salvage value

Lease payments

Pre-tax Total

Cumulative IRR

Cumulative NPV

Tax Investor (Lessor) After-tax

Purchase price of asset

IBI income

CBI income

Pre-tax salvage value

Lease payments

Share of project cash total

ITC

PTC

Share of project tax benefit/liability

After-tax total

Cumulative IRR

Cumulative NPV

Maximum IRR

Total

Cumulative IRR

Cumulative NPV

Developer Pre-tax

Developer equity in Lessee LLC (funding of reserve accounts)

Distribution of development fee

Release of major equipment replacement reserves

Release of working capital reserves

Release of lease payment reserve

Interest earned on lease payment reserve

Developer (Lessee LLC) operating margin

Total

Cumulative IRR

Cumulative NPV
IRR

NPV

Developer After-tax

Developer equity in Lessee LLC (funding of reserve accounts)

Distribution of development fee

Release of major equipment replacement reserves

Release of working capital reserve

Release of lease payment reserve

Interest earned on lease payment reserve

Developer (Lessee LLC) operating margin

Share of project cash

Share of project tax benefit/liability

Developer fee tax liability

Total

Cumulative IRR

Cumulative NPV
IRR

NPV

Incentives

The incentive cash flow rows show the value of cash incentives and tax credits, which are used to calculate cash flows described above.

IBI (Investment Based Incentives)

Each IBI (federal, state, utility, other) applies in Year Zero of the project cash flow.

Because you can specify each IBI on the Incentives page as either an amount or a percentage, SAM calculates the value of each IBI as the sum of two values:

IBI as Amount = Amount

IBI as Percentage = Total Installed Cost ($) × Percentage (%), up to Maximum

IBI in Year 0 = IBI as Amount + IBI as Percentage

Where *Amount*, *Percentage* and *Maximum* are the values that you specify on the Incentives page, and *Total Installed Cost* is from the System Costs page.

Total IBI is the sum of the four IBI values (federal, state, utility, other).

Note. The IBI amount reduces the after tax cost flow in Year Zero, and the debt balance in Year One. This is because SAM assumes that debt payments begin in Year One, when the project is generating or saving electricity.

CBI (Capacity Based Incentives))

Each CBI (federal, state, utility, other) applies in Year Zero of the project cash flow:

CBI in Year 0 = System Capacity (W) × Amount ($/W), up to Maximum

Where System Capacity is the rated capacity of the system, and *Amount* and *Maximum* are the values you specify on the Incentives page.

Total CBI is the sum of the four CBI values (federal, state, utility, other).

The system nameplate capacity depends on technology being modeled. SAM converts the capacity value to the appropriate units (MW, kW, or W) before using it in calculations. For the photovoltaic models, the capacity is a DC power rating, and for the others it is an AC power rating. For the BeOpt/TRNSYS Solar Water Heating Model, the capacity is a thermal rating, while for the others it is an electric rating.

Table 32. Nameplate system capacity values for each technology.

Performance Model	System Capacity	Input Page
Flat Plate PV (DC)	Total Array Power (Wdc)	Array
PV PVWatts (DC)	DC Rating (kWdc)	PVWatts Solar Array
High-X Concentrating PV (DC)	System Nameplate Capacity	Array
CSP Parabolic Trough - Physical (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Parabolic Trough - Empirical (AC)	Estimated Net Output at Design (MWe)	Power Block
CSP Molten Salt Power Tower (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Cycle
CSP Direct Steam Power Tower (AC)	Net nameplate capacity (MWe)	Power Cycle
CSP Dish Stirling (AC)	Total Capacity (kWe)	Solar Field
CSP Generic Solar (AC)	Estimated Net Output at Design (Nameplate) (MWe)	Power Block
CSP Linear Fresnel (AC)	Net nameplate capacity (MWe)	Power Cycle
Generic System (AC)	Nameplate Capacity (kWe)	Power Plant
Geothermal	Net Plant Output (MWe)	Plant and Equipment
Geothermal Co-Production	Actual Expected Plant Output (kWe)	Resource and Power Generation
BeOpt/TRNSYS Solar Water Heating Model (Thermal)	Nameplate Capacity (kWt)	SWH System
Wind Power (AC)	System Nameplate Capacity (kWe)	Wind Farm
Biopower (AC)	Nameplate Capacity, Gross (kWe)	Plant Specs

PBI (Performance Based Incentive)

Each PBI (federal, state, utility, other) applies in Years One and later of the project cash flow, up to the number of years you specify:

PBI in Year n = Amount ($/kWh) × Energy in Year n (kWh) × (1 + Escalation)^(n-1), up to Term

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in Energy row of the cash flow table (described above).

Note. If you use an annual schedule to specify year-by-year PBI amounts, SAM ignores the escalation rate.

Total PBI is the sum of the four PBI amounts (federal, state, utility, other).

Important Note! If you specify a PBI amount on the Cash Incentives page, be sure to also specify the incentive term. If you specify a term of zero, the incentive will not appear in the cash flow table.

PTC (Production Tax Credit)

The state and federal PTC each apply in Year One and later of the project cash flow, up to the number of years you specify:

PTC in Year n = Amount ($/kWh) × (1 + Escalation)^(n-1) × Energy in Year n (kWh)

Where *Amount*, *Term*, and *Escalation* are the values you specify on the Incentives page, and *Energy* is the value displayed in the Energy row of the cash flow table (described above).

SAM rounds the product *Amount ($/kWh) × (1 + Escalation)^(n-1)* to the nearest multiple of 0.1 cent as described in Notice 2010-37 of IRS Bulletin 2010-18.

Note. If you specify year-by-year PTC rates on the Incentives page using an Annual Schedule instead of a single value, SAM ignores the PTC escalation rate.

ITC (Investment Tax Credit)

The state and federal ITC each apply only in Year One of the project cash flow. For ITCs that you specify as a fixed amount:

ITC in Year One = Amount

Where *Amount* is the value you specify in the Incentives page.

For ITCs that you specify as a percentage of total installed costs:

ITC in Year One = (Total Installed Cost ($) - ITC Basis Reduction ($)) × Percentage (%), up to Maximum

Where *Total Installed Cost* is from the System Costs page, and *Percentage* and *Maximum* are the values you specify on the Incentives page.

ITC Basis Reduction applies only to the Commercial and Utility financing options, and depends on whether the project includes any investment-based incentives (IBI) or capacity-based incentives (CBI) specified on the Incentives page with checked boxes under **Reduces Depreciation and ITC Bases**. For each IBI or CBI with a check mark, SAM subtracts the incentive amount from the total installed cost to calculate the ITC.

ITC Basis Reduction = IBI + CBI

Where *IBI* and *CBI* are the incentives that you have specified reduce the ITC basis on the Incentives page.

Reserve Accounts

Reserve accounts include debt service, working capital reserve, and major equipment replacement reserves. The reserve account amounts depend on the following inputs from the Financing page:

- Inflation Rate
- Debt Service Reserve Account (months P&I)
- Working Capital Reserve Months of Operating Costs
- Major Equipment Replacement Reserve Account [1-3] Frequency (years)
- Major Equipment Replacement [1-3] (Year 1 $)

Lease Payment Reserve (Sale Leaseback only)

Lease Payment Reserve = Tax Investor (Lessor) Required Lease Payment Reserve (months) ÷ 12 × Total Developer Pre-tax Cash Flow from Operating Activities in Year n+1

Debt Service Reserve

The debt service reserve applies in Year Zero and later:

Debt Service Reserve = Debt Service Reserve Account (months P&I) ÷ 12 × Total P&I in Year n+1

Where *Debt Service Reserve Account (months P&I)* is from the Financing page, and *Total P&I in Year n+1* is described under Debt above.

Working Capital Reserve

Working capital reserve applies in Year Zero and later:

Working Capital Reserve = Months of Operating Costs × Operating Expenses in Year n+1

Where *Months of Operating Costs* is from the Financing page, and *Operating Expenses in Year n+1* is described above.

Major Equipment Replacement Reserves

You can specify up to three major equipment reserve accounts on the Financing page. For each account, the amount applies in Year One and later of the cash flow:

Major Equipment Reserve in Year n = Major Equipment Reserve in Year n-1 + Funding + Release of Funds

Where Major Equipment Reserve in Year Zero = 0, and:

Funding = Release of Funds in Year of Next Replacement ÷ Replacement Frequency

Release of Funds in Year of Next Replacement = - Replacement Cost in Year One $ × (1 + Inflation Rate)^(n-1)

Where *Replacement Frequency*, *Replacement Cost in Year One $*, and *Inflation Rate* are from the Financing page

Depreciation and ITC

The federal and state Depreciation and ITC tables show the depreciable basis calculation for each of the up to seven depreciation classes for federal and state tax purposes:

- The total depreciable amount includes the total installed cost, development fee, equity closing cost, debt service reserve, working capital reserve, and for the Sale Leaseback financing option, the lease payment reserve.
- The depreciation class allocations on the Financing page determine how the depreciable basis is allocated to the different depreciation classes (MACRS 5-yr, Straight Line, etc.).
- For each state and federal IBI and CBI with **Reduces Depreciation and ITC Bases** checked on the Incentives page, the full incentive amount reduces the depreciable basis.
- For each state and federal ITC with **Reduces Depreciation Basis** checked on the Incentives page, 50% of the tax credit amount reduces the depreciable basis.
- For each depreciation class with a checked box under **Bonus Depreciation** on the Financing page, the depreciable basis is the product of the bonus depreciation percentage and the adjusted depreciable basis. (The adjusted depreciable basis is the total depreciable after incentives and tax credit adjustments.)

- For state and federal taxes, depreciation for major equipment replacement reserves uses the class specified on the Financing page.

The depreciation amounts depend on the total installed cost from the System Costs page, and the following inputs from other pages.

From the Financing page:

- Development Fee
- Debt Closing Costs
- Debt Closing Fee
- Equity Closing Cost
- Construction Financing
- Other Financing Cost

From the Incentives page:

- State ITC as Percentage
- State ITC Maximum
- State ITC as Amount
- Federal ITC as Percentage
- Federal ITC Maximum
- Federal ITC as Amount
- Status of **Reduces Depreciation Basis** check boxes
- The amounts and percentages of any incentive with **Reduces Depreciation and ITC Bases** checked

From the Depreciation page:

- Allocations for each depreciation class
- Bonus depreciation amounts and applicable depreciation classes
- ITC qualification status of depreciation classes

The depreciation amounts also depend on the following cash flow values:

- Debt service reserve
- Working capital reserve
- IBI (only for incentives shown to reduce depreciation basis on Incentives page)
- CBI (only for incentives shown to reduce depreciation basis on Incentives page)
- Debt funding
- For state depreciation, the federal ITC basis disallowance amounts for each depreciation class
- For federal depreciation, the state ITC basis disallowance amounts for each depreciation class

Gross Depreciable Basis with IBI and CBI Reductions Before ITC Reductions

For each depreciable class, the depreciable basis before reduction by the ITC is the gross depreciable basis less IBI and CBI amounts for incentives on the Cash Incentives page with **Reduces Depreciation and ITC Bases** checked.

> **Note.** The IBI and CBI reduce the depreciation basis for state taxes only when **State** under **Reduces Depreciation and ITC Bases** is checked. Similarly, the IBI and CBI reduce the depreciation basis for federal taxes only when **Federal** under **Reduces Depreciation and ITC Bases**.

% of Total Depreciable Basis

The normalized allocation for each depreciation class allocation:

% of Total Depreciable Basis = Allocation ÷ Sum of Allocations

Where *Allocation* is the percentage for the given depreciable class, and *Sum of Allocations* is the sum of all allocations from the Financing page.

Gross Amount Allocated

The gross depreciable basis before reductions for each depreciation class:

Gross Amount Allocated = % of Total Depreciable Basis × Total Depreciable Amount

Where % of Total Depreciable Basis is described above, and

Total Depreciable Amount = Total Installed Cost + Development Fee + Equity Closing Cost + Debt Closing Costs + Debt Closing Fee × Funding + Debt Service Reserve + Working Capital Reserve + Lease Payment Reserve

Where *Total Installed Cost* is from the System Costs page; *Development Fee*, *Equity Closing Cost*, *Debt Closing Costs*, and *Debt Closing Fee* are from the Financing page; and *Debt Service Reserve*, *Working Capital Reserve* and *Lease Payment Reserve* (Sale Leaseback financing option only) are other values in the cash flow described above

Reduction: IBI

The reduction in depreciation basis from IBI payments:

Reduction IBI = Total IBI that Reduce Depreciation × % of Total Depreciable Basis

Where *Total IBI that Reduce Depreciation* is the sum of IBI values in the cash flow for incentives with **Reduces Depreciation and ITC Bases** checked on the Incentives page. For the state depreciation table, **State** must be checked for the incentive to reduce the state depreciation basis. For the federal depreciation table, **Federal** must be checked. *% of Total Depreciable Basis* is the allocation for the depreciation class described above.

Reduction: CBI

The reduction in depreciation basis from CBI payments:

Reduction CBI = Total CBI that Reduce Depreciation × % of Total Depreciable Basis

Where *Total CBI that Reduce Depreciation* is the sum of CBI values in the cash flow for incentives with **Reduces Depreciation and ITC Bases** checked on the Incentives page. For the state depreciation table, **State** must be checked for the incentive to reduce the state depreciation basis. For the federal depreciation table, **Federal** must be checked. *% of Total Depreciable Basis* is the allocation for the depreciation class described above.

Depreciable Basis Prior to ITC

The depreciable basis reduced by CBI and IBI amounts:

Depreciable Basis Prior to ITC = Gross Amount Allocated - Reduction: IBI - Reduction: CBI

ITC Reduction

For each ITC on the Incentives page with **Reduces Depreciation Basis** checked, 50% of the ITC amount can be included in the depreciable basis for each depreciable class with **ITC Qualification** checked on the Depreciation page. SAM calculates the ITC reduction amount for ITCs that you specify on the Incentives page a percentage of the total installed costs with a maximum amount, and ITCs that you specify as a fixed amount.

> **Note.** The ITC reduces the depreciation basis for state taxes only when **State** under **Reduces Depreciation Basis** is checked on the Incentives page, and when **State** is checked under **ITC Qualification** for the depreciation class on the Depreciation page. Similarly, the ITC reduces the depreciation basis for federal taxes only when **Federal** is checked under **Reduces Depreciation Basis** and under **ITC Qualification** for the depreciation class.

For each ITC specified as a percentage and maximum on the Incentives page, the *ITC Basis Disallowance* is the amount that may be available for depreciation basis reduction. (The ITC Reduction amounts are the amounts actually available.):

ITC Qualifying Costs

For depreciation classes with **ITC Qualification** checked on the Depreciation page:

ITC Qualifying Costs = Depreciable Basis Prior to ITC

% of ITC Qualifying Costs

For each depreciable class:

% of ITC Qualifying Costs = ITC Qualifying Costs ÷ Total Depreciable Basis Prior to ITC

Where *Total Depreciable Basis Prior* to ITC is the sum of *Depreciable Basis Prior to ITC* for all depreciable classes.

ITC Amount

ITC Amount = % of ITC Qualifying Costs × ITC Qualifying Costs

ITC Basis Disallowance

The ITC depreciation basis disallowance is 50% of the ITC amount:

ITC Basis Disallowance = ITC Amount × 0.5

For each ITC specified as a fixed amount on the Incentives page, the ITC Basis Disallowance is the amount that may be available for depreciation basis reduction. (The ITC Reduction amounts are the amounts actually available.):

ITC Amount

For each depreciable class, the Total ITC Amount is the amount that may be available for depreciation reduction:

ITC Amount = Total ITC Amount × % of ITC Qualifying Costs

Where, for the state depreciation table, *Total ITC Amount* is the state ITC amount from the Incentives page. For the federal depreciation table, *Total ITC Amount* is the federal ITC amount from the Incentives page.

ITC Basis Disallowance

The ITC depreciation basis disallowance is 50% of the ITC amount:

ITC Basis Disallowance = ITC Amount × 0.5

The depreciable basis after ITC reduction is the sum of the total ITC basis disallowance values for the ITCs with **Reduces Depreciation Basis** checked on the Incentives pages.

ITC Reduction: State

ITC Reduction: State = ITC Basis Disallowance (ITC as %) + ITC Basis Disallowance (ITC as Fixed Amount)

Where the ITC basis disallowance values are from the state depreciation table for the ITCs that reduce depreciation basis.

ITC Reduction: Federal

ITC Reduction: Federal = ITC Basis Disallowance (ITC as %) + ITC Basis Disallowance (ITC as Fixed Amount)

Where the ITC basis disallowance values are from the federal depreciation table for the ITCs that reduce depreciation basis.

Depreciable Basis after ITC Reduction

Depreciable Basis after ITC Reduction = Depreciable Basis Prior to ITC - ITC Reduction:State - ITC Reduction:Federal

Bonus Depreciation

For each depreciation class that qualifies for bonus depreciation as indicated by the check boxes under Bonus Depreciation on the Depreciation page, bonus depreciation percentage applies to the depreciable basis.

Note. The bonus depreciation percentage applies to the depreciation basis for state taxes only when **State** under **Bonus Depreciation** is checked. Similarly, the bonus depreciation percentage applies for federal taxes only when **Federal** under **Reduces Depreciation Basis** is checked.

First Year Bonus Depreciation

For each depreciation class with **Bonus Depreciation** checked on the Depreciation page:

First Year Bonus Depreciation = Depreciable Basis after ITC Reduction × Bonus Depreciation Percentage

Where Bonus Depreciation Percentage is from the Depreciation page: The state bonus percentage applies to the state depreciation table, and the federal percentage applies to the federal depreciation table.

Depreciable Basis

The depreciable basis after IBI, CBI, ITC and bonus depreciation reduction is the basis to which the depreciation percentages defined by the depreciation class apply.

Depreciable Basis after Bonus Reduction = Depreciable Basis after ITC Reduction - First Year Bonus Depreciation

The following table shows the depreciation percentage by year for each depreciation class. For each depreciation class, the percentage is applied to the depreciable basis amount for the given year in the cash flow:

Years 1-10	1	2	3	4	5	6	7	8	9	10
5-yr MACRS	20.0	32.0	19.2	11.5	11.5	5.8				
15-yr MACRS	5.0	9.5	8.6	7.7	6.9	6.2	5.9	5.9	5.9	5.9
5-yr SL	10.0	20.0	20.0	20.0	20.0	10.0				
15-yr SL	3.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
20-yr SL	2.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	1.3	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 11-20	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
15-yr MACRS	5.9	5.9	5.9	5.9	5.9	3.0				
15-yr SL	6.7	6.7	6.7	6.7	6.7	3.3				
20-yr SL	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 21-30	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
20-yr SL	2.5									
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Years 31-40	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
39-yr SL	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	1.3

21 Performance Model Results

The performance model outputs are hourly (or sub-hourly) simulation results from the SAM performance models. The performance model variables that appear in the time series results are different for different technologies.

The Time Series Variable topics are:

- Performance Results Overview
- Flat Plate PV
- PVWatts
- High-X Concentrating PV
- Parabolic Trough (Physical)
- Parabolic Trough (Empirical)
- Power Tower (Molten Salt)
- Power Tower (Direct Steam)
- Generic Solar System
- Linear Fresnel
- Dish Stirling
- Solar Water Heating

21.1 Performance Results Overview

The performance model results are hour-by-hour values calculated during simulations. After running simulations, SAM displays performance model results on the Results page.

- Tables allows you to choose the hourly data to display and export it to the clipboard or a file. Tables also display annual and monthly totals or averages of some of the time series values.
- Time Series displays time series graphs and statistical summary graphs of the hourly data.

Tables

- **Single Values** displays annual totals of hourly values for Year 1 in of the project cash flow.
- **Monthly Values** displays monthly totals of hourly values for Year 1 in the project cash flow.
- **Annual Data** displays annual and monthly totals of hourly values for all years of the project cash flow.
- **Hourly Data** displays hourly values.

Time Series

- **Time Series** displays hourly values for one or more variables in a two-dimensional graph with time as the x-axis.
- **Heat Map** displays a single variable's hourly values for Year 1 in an hour-by-month matrix.
- **Monthly Profile** displays a single variable's average 24-hour daily profiles for each month.
- **PDF / CDF** displays a frequency histogram of the hourly values for a single variable.
- **Duration Curve** displays hourly values of a single variable sorted by the number of hours each value is equaled or exceeded.
- **Scatter Plot** displays hourly values for two variables.

Raw TRNSYS Simulation Data Files

For performance models that use the TRNSYS simulation engine (all CSP models) SAM stores simulation data in a comma-delimited text file that you can open with a text editor, spreadsheet program, or other software.

- Press the Shift-F9 keys to open the folder containing the file. The file name is something like *Case Name STEP 60m ID 108128160.out*.
- If you frequently work with the simulation output file, you can choose to have SAM save a permanent copy of the file in a folder of your choice.

To save simulation output data in a folder of your choice:

1. In Simulator Options, under **Hourly Output Files**, check Save **TRNYSYS hourly data, list, and log files in folder**.

   If the check box is inactive, the performance model you are using does not use the TRNSYS simulation engine.

2. Type the folder's path and name, or click  to navigate to the folder.

Notes.

SAM does not delete files from the folder you specify. However, it uses the same file name each time it runs a simulation, so if you want to save files from different simulations, you should manually rename the file after each simulation so that SAM does not overwrite the data.

Older versions of SAM included a free stand-alone program called DView for viewing time series data. You can download DView from http://www.mistaya.ca/software/dview.htm

For descriptions of the hourly and monthly performance model results, see:

- Flat Plate PV
- PVWatts
- High-X Concentrating PV
- Parabolic Trough (Physical)
- Parabolic Trough (Empirical)
- Power Tower (Molten Salt)
- Power Tower (Direct Steam)
- Generic Solar System
- Linear Fresnel
- Dish Stirling
- Solar Water Heating

21.2 Flat Plate PV

After running simulations, SAM displays time series results for the flat plate model on the Results page Tables and Time Series graphs.

Note. For simulations that involve time-of-delivery pricing, results include additional variables described in Savings and Revenue.

Hourly Data

Variable Name	Units	Description
Absolute air mass		The optical length of the atmosphere at sea level, empirically corrected for atmospheric pressure to account for elevation and weather effects.
Albedo		The albedo (ground reflectance) value, either from the weather file, or from the input value on the Array page, depending on whether Use albedo in weather file if it is specified is checked.

Variable Name	Units	Description
Ambient temperature	C	Ambient temperature from the weather file (dry-bulb temperature).
Beam irradiance	kW/m2	The direct normal radiation value from the weather file.
Diffuse irradiance	kW/m2	The diffuse horizontal radiation value from the weather file.
Global horizontal irradiance	kW/m2	Global horizontal radiation from weather file.
Gross ac output	kWh	System AC output before AC derating factor.
Gross dc array output	kWh	Array DC output before DC derating factor.
Hourly Energy Delivered	kWh	Net AC electricity after factors from the Performance Adjustment page.
Input radiation	kWh	Product of the total radiation incident on array and the total area of photovoltaic modules in the array.
Inverter clipping loss	Wac	Inverter output in excess of the inverter's rated output, if any. During hours with clipping losses, the inverter's AC ouput in kWh/h should be equal to the inverter's rated capacity in kW.
Inverter dc input voltage	V	The DC voltage at the inverter input, calculated as the average of the four string voltages.
Inverter efficiency	%	The inverter DC-to-AC conversion efficiency, equal to the gross AC output in kWhac divided by the net DC array output in kWhdc during hours when the array output is not zero.
Inverter night time loss	Wac	Inverter's AC electricity consumption at night when the array's output is zero, equal to the value from the Inverter page.
Inverter power consumption loss	Wdc	Inverter's DC electricity consumption during all hours, calculated based on the value from the Inverter page. The power consumption loss depends on the inverter's DC input power and AC output power, and on the inverter parameters. SAM does not calculate this value with the Inverter Datasheet model with weighted efficiency, or with the Inverter Part Load model because the loss is assumed to be included in the weighted efficiency values.

Variable Name	Units	Description
Net ac output	kWh	System AC output after AC derating factors.
Net dc array output	kWh	Array DC output after DC derating factor.
Nominal POA total radiation	kWh	Total radiation incident on the photovoltaic array before shading and soiling factors are applied.
POA total radiation after shading and soiling	kWh	Total radiation incident on the photovoltaic array after shading and soiling factors are applied.
POA total radiation after shading only	kWh	Total radiation incident on thephotovoltaic array after shading factors are applied, but before soiling factors are applied.
Self-shading diffuse derate		Portion of shelf-shading derate factor due to shading of diffuse radiation.
Self-shading derate		Total DC derate factor for self-shading.
Self-shading diffuse loss	kW/m2	Quantity of incident diffuse radiation lost due to self-shading.
Self-shading reflected derate		Portion of self-shading derate factor due to shading of reflected radiation.
Solar altitude angle	deg	Altitude angle of the sun.
Solar azimuth angle	deg	Azimuth angle of the sun.
Solar zenith angle	deg	Zenith angle of the sun.
Subarray 1..4 Angle of incidence	deg	Solar angle of incidence on the photovoltaic array.
Subarray 1..4 Axis rotation for 1 axis trackers	deg	For 1-axis tracking, tracker's actual axis rotation angle for this subarray. See ideal axis rotation below.
Subarray 1..4 Module efficiency	%	Module conversion efficiency.
Subarray 1..4 Beam irradiance shading factor	frac	The shading factor for this subarray that applies to the current hour.
Subarray 1..4 Cell temperature	C	Temperature of module cells in this subarray.
Subarray 1..4 DC string voltage	V	String voltage for this subarray. (Used to ensure array voltage is within inverter input voltage limits.)
Subarray 1..4 Gross DC output	kWh	The DC output for this subarray before DC derating .

Variable Name	Units	Description
Subarray 1..4 Ideal axis rotation (for 1 axis trackers) (deg)	deg	For one-axis tracking, the value of this subarray angle of rotation that minimizes its incidence angle with the sun. When backtracking is enabled for one-axis trackers, the actual axis rotation angle is different from the ideal rotation during morning and afternoon hours to avoid shading. The difference between the ideal axis rotation and the axis rotation is the rotation adjustment due to backtracking.
Subarray 1..4 Nominal POA total irradiance	kW/m2	The total radiation incident on this subarray.
Subarray 1..4 POA beam irradiance after shading and soiling	kW/m2	Direct normal radiation incident on this subarray after soiling factor.
Subarray 1..4 POA diffuse irradiance after shading and soiling	kW/m2	Diffuse radiation incident on this subarray after soiling factor.
Subarray 1..4 POA total irradiance after shading and soiling	kW/m2	Total radiation incident on this subarray. (Sum of incident beam and incident diffuse.)
Subarray 1..4 POA total irradiance after shading only	kW/m2	Total radiation incident on this subarray after shading factors but before soiling factors are applied.
Subarray 1..4 Soiling derate	frac	Soiling derate factor for this subarray.
Subarray 1..4 Surface azimuth	deg	Angle of the array from due north for this subarray.
Subarray 1..4 Surface tilt	deg	Angle of the array from the horizontal for this subarray.
Sun up over horizon		A value of zero indicates that the sun is below the horizon. A value greater than zero indicates that the sun is above the horizon.
Wind speed	m/s	Wind speed from weather file.

Monthly Data

Variable Name	Units	Description
Beam Incident Radiation	kWh/m2	Total direct normal radiation incident on the array by month.
Net ac output	kWh	Total derated AC output of the system by month. (Equal to Monthly Energy.)
Net dc output	kWh	Total derated DC output of the array by month.
Monthly Energy Delivered	kWh	Total AC output of the system by month after hourly performance adjustments.

Variable Name	Units	Description
Total Incident Radiation	kWh/m2	Total radiation incident on the array by month.

21.3 PVWatts

After running simulations, SAM displays performance output data for the PVWatts model on the Results page Tables and Time Series graphs.

Note. For simulations that involve time-of-delivery pricing, results include additional variables described in Savings and Revenue.

Hourly Data

Variable Name	Units	Description
Ambient Temp	'C	Ambient temperature (dry-bulb) from the weather file
Beam Normal	kW/m2	Direct normal radiation from the weather file
Cell Temp	'C	Cell temperature
DC Output	kWh	DC output of the array.
Diffuse Horizontal	kW/m2	Diffuse horizontal radiation from the weather file
Global Horizontal		Total horizontal radiation from the weather file
Hourly Energy	kWh	System AC output
Plane of Array	kW/m2	Incident total radiation calculated by the weather processor based on solar angles determined from the latitude and longitude values in the weather file and array orientation options specified on the Array page.
Shading Factor for Beam Radiation		Shading factor applied to the incident direct normal radiation.
Wind Speed	m/s	Ambient wind speed from the weather file.

Monthly Data

Variable Name	Units	Description
DC Output	kWh	Monthly total of hourly array DC output values.
Monthly Energy	kWh	Monthly total of hourly hourly energy values.
Monthly Energy Delivered	kWh	Monthly total of hourly energy delivered values.

21.4 High-X Concentrating PV

After running simulations, SAM displays time series results for the high-X concentrating PV (HCPV) model on the Results page Tables and Time Series graphs.

Note. For simulations that involve time-of-delivery pricing, results include additional variables described in Savings and Revenue.

Hourly Data

Variable Name	Units	Description
AC gross	kWh	System gross AC output, before AC derate.
Beam	W/m2	Direct normal radiation from weather file.
Cell eff	%	Cell conversion efficiency at POA on cell (from table on Module page).
Cell temp	'C	Cell temperature.
DC gross	kWh	Array gross DC output, before DC derate.
DC net	kWh	Array DC output, after DC derate.
Dry bulb temp	'C	Ambient temperature from weather file.
Hourly Energy	kWh	System net AC output, after AC derate.
Hourly Energy Delivered	kWh	System output after hourly performance adjustments.
Input radiation	kWh	Product of total radiation incident on array and array area.
Module backplate temp	'C	Temperature of back of module.
Module eff	%	Module conversion efficiency (input radiation to DC gross).
POA on cell	W/m2	Total radiation incident on cell.
Relative air mass		Atmospheric optical length.
Shading derate		DC derate factor due to array shading.
Solar azimuth	deg	Azimuth angle of the sun.
Solar zenith	deg	Zenith angle of the sun.
Sun up	0/1	0 = no sun, 1 = sun.
Tracker azimuth	deg	Array angle from due north.
Tracker tilt	deg	Array tilt angle from horizontal.
Wind speed	m/s	Wind speed from weather file.

Monthly Data

Variable Name	Units	Description
AC net	kWh	Total system AC ouput, after AC derate.
Beam	Wh/m2	Total direct normal radiation incident on array.
DC net	kWh	Total array DC ouput, after DC derate.
Input Radiation	kWh	Product of monthly beam radiation and module area.
Monthly Energy Delivered	kWh	Total AC output of the system by month after hourly performance adjustments.

21.5 Parabolic Trough (Physical)

After running simulations, SAM displays time series results for the physical trough model on the Results page Tables and base case

Notes.

The solar radiation values (DNI) represent total energy values over the time step, and are equivalent to the values in the weather file. Temperature and wind speed values are mid-point values calculated by the weather data processor by averaging the end-of-time step wind speed from the previous time step with the end-of-time step wind speed from the current time step in the weather file.

For simulations that involve time-of-delivery pricing, results include additional variables described in Time Dependent Pricing Overview.

Hourly Data

Name	Units	Notes
Atmospheric pressure	atm	
Auxiliary heater fuel consumption	MMBTU	
Auxiliary heater operation parasitic load	MWh	
Average receiver loss per meter	W/m	
Balance of plant parasitic load	MWh	
Cold tank HTF volume	m3	
Cold tank mass level	kg	
Collector average optical efficiency	none	
Collector cosine effect (cos theta)	none	
Collector drives electric consumption	MWh	
Collector incidence angle (theta)	deg	
Condenser operating pressure	Pa	
Cooling system parasitic power	MWh	

Name	Units	Notes
DNI-cosine effect product	W/m2	
Direct normal irradiation	W/m2	
Dry-bulb temperature	C	
Dumped thermal energy (approx.)	MWh	
End loss effect	none	
Field operation fraction	none	
Field pumping power	MWh	
Fixed parasitic load	MWh	
Fossil backup mass flow rate	kg/hr	
Fraction of operating condenser bays	none	
Freeze protection energy	MWh	Energy supplied by electric heat trace equipment to keep the solar field HTF temperature above the field protection temperature.
Gross electric power output	MWh	
Hot tank HTF volume	m3	
Hot tank mass level	kg	
Hour of the day	hour	
Hourly Energy Delivered	kWh	
Incidence angle modifier	none	
Incident energy-cosine effect product	MW	
Net electric power output	MWh	
Power block HTF mass flow rate	kg/hr	
Power cycle HTF inlet temperature	C	
Power cycle HTF return temperature	C	
Power cycle efficiency (net)	none	
Power cycle/TES pumping power	MWh	
Receiver thermal losses	MWh	
Row shadowing effect	none	
Single loop mass flow rate	kg/s	
Solar azimuth angle	deg	
Solar elevation angle	deg	
Solar field mass flow rate	kg/hr	
Solar field pressure drop	bar	
Solar field startup energy	MWh	
Solar field thermal output	MWh	
TES discharge mass flow rate - field side	kg/hr	
TES discharge mass flow rate - tank side	kg/hr	
TES thermal losses	MWh	

Name	Units	Notes
Tank freeze protection energy	MWh	Energy supplied by electric tank heaters to keep the storage tanks above the tank heater set point temperature.
Temperature at cold header inlet	C	
Temperature at collector inlet	C	
Temperature at hot header outlet	C	
Temperature into cold tank	C	
Temperature into hot tank	C	
Temperature into storage loop	C	
Temperature of cold tank	C	
Temperature of hot tank	C	
Temperature out of storage loop	C	
Thermal energy absorbed	MWh	
Thermal energy delivered by aux backup	MWh	
Thermal energy to the power cycle	MWh	
Thermal energy to thermal storage	MWh	
Total header piping heat loss	MWh	
Total HTF volume in TES	m3	
Total incident thermal energy	MWh	
Water consumption mass flow rate	kg/hr	
Wet-bulb temperature	C	
Wind velocity	m/s	

Monthly Data and Single Values

Descriptive name	SAM Units
Gross Electric Output	kWh
Net Electric Output	kWh
Total Incident Thermal Energy	MWh
Thermal Energy Absorbed by HTF	MWh
Solar Field Thermal Output	MWh
Aux. Fuel Consumption	MMBtu
Dumped Thermal Energy (approx.)	MWh
Water usage	m^3

21.6 Parabolic Trough (Empirical)

After running simulations, SAM displays time series results for the empirical trough model on the Results page Tables and Time Series graphs.

Notes.

The solar radiation values (DNI) represent total energy values over the time step, and are equivalent to the values in the weather file. Temperature and wind speed values are mid-point values calculated by the weather data processor by averaging the end-of-time step wind speed from the previous time step with the end-of-time step wind speed from the current time step in the weather file.

For simulations that involve time-of-delivery pricing, results include additional variables described in Time Dependent Pricing Overview.

Hourly Data

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
Day_of_year	day	Day of the year	day
MONTH	month	Month	month
Hour_of_month	hr	Hour of the month	hr
Day_of_month	day	Day of the month	day
Hour_of_day	hr	Hour of the day	hr
TOUPeriod	none	Time-of-dispatch period	none
SolAz	deg	Solar azimuth angle	deg
SolAlt	deg	Solar elevation angle	deg
DNI	W/m2	Direct normal irradiation	W/m2
T_dry_bulb	C	Dry-bulb temperature	C
V_wind	m/s	Wind velocity	m/s
Theta	deg	Collector incidence angle (theta)	deg
Costheta	none	Collector cosine effect (cos theta)	none
TrckAngl	deg	Collector tracking angle	deg
IAM	none	Incidence angle modifier	none
RowShadow	none	Row shadowing effect	none
Endloss	none	End loss effect	none
Theta	deg	Collector incidence angle (theta)	deg
Q_nipCosTh	W/m2	DNI-cosine effect product	W/m2
QSF_nipCosTh	MWh	Incident energy-cosine effect product	MWh
ColOptEff	none	Solar field collection efficiency	none
Q_DNI_on_SF	MWh	Incident energy on solar field	MWh
QSF_Abs	MWh	Solar field energy before thermal losses	MWh
Q_abs	W/m2	Solar field energy before thermal losses (per sq m)	W/m2
QSF	MWh	Solar field thermal output	MWh
Q_col	W/m2	Solar field thermal output (per sq m)	W/m2
RecHtLoss	MWh	Total solar field thermal loss	MWh
QSF_HCE_HL	MWh	Receiver thermal loss	MWh

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
QSF_Pipe_HL	MWh	Total header piping heat loss	MWh
SF_Tin	C	Temperature at cold header inlet	C
SF_TOut	C	Temperature at hot header outlet	C
SF_MassFlow	kg/s	Solar field mass flow rate	kg/s
SF_AveTemp	C	Average solar field HTF temperature	C
QsfWarmUp	MWh	Solar field warmup energy	MWh
Q_htf_FrPr	MWh	Solar field freeze protection energy consumption	MWh
Q_htf_FP_TES	MWh	TES freeze protection energy consumption	MWh
Q_htf_FP_Htr	MWh	Tank freeze protection energy	MWh
Q_to_TES	MWh	Thermal energy to storage	MWh
Q_from_TES	MWh	Thermal energy from storage	MWh
E_in_TES	MWh	Energy in thermal storage	MWh
Q_TES_HL	MWh	TES thermal losses	MWh
Q_TES_Full	MWh	Dumped energy from full TES	MWh
Q_to_PB	MWh	Thermal energy to the power cycle	MWh
Q_turb_SU	MWh	Power cycle startup energy	MWh
Q_min	none	Dumped energy below minimum operation	none
Q_dump	MWh	Dumped energy (other)	MWh
E_gross_solar	MWh	Gross electricity output (solar only)	MWh
E_gross_fossil	MWh	Gross electricity output (fossil only)	MWh
Q_gas	MWh	Auxiliary heater fuel consumption	MWh
E_gross	MWh	Gross electric power output	MWh
E_net	MWh	Net electric power output	MWh
E_parasit	MWh	Total parasitic consumption	MWh
E_par_SF	MWh	Collector drives electric consumption	MWh
E_par_cHTF	MWh	Field pumping power	MWh
E_par_hHTF	MWh	Power cycle/TES pumping power	MWh
E_par_Anti	MWh	Antifreeze pumping parasitics	MWh
E_par_Htr	MWh	Auxiliary heater parasitic load	MWh

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
E_par_PB	MWh	Fixed parasitic load	MWh
E_par_BOP	MWh	Balance of plant parasitic load	MWh
E_par_CT	MWh	Cooling system parasitic power	MWh
E_par_Offline	MWh	Parasitics consumed while plant is offline	MWh
E_par_Online	MWh	Parasitics consumed while plant is online	MWh

Monthly Data and Single Values

Monthly data file name	TRNSYS Units	Descriptive name	SAM Units
Gross_Electric_Generation	MWh	Gross Electric Output	kWh
E_net	MWh	Net Electric Output	kWh
Q_DNI_on_SF	MWh	Total Incident Thermal Energy	MWh
QSF_nipCosTh	MWh	DNI-cosine effect product	MWh
SFAvailableEnergy	MWh	Solar Field Available Energy	MWh
QSF_Abs	MWh	Thermal Energy Absorbed by HTF	MWh
QSF	MWh	Solar Field Thermal Output	MWh
Q_to_PB	MWh	Thermal Energy to Power Block	MWh
QSF_Pipe_HL	MWh	Piping Thermal Losses	MWh
QSF_HCE_HL	MWh	Receiver Thermal Losses	MWh
Q_TES_Full	MWh	Energy Losses Due to Full Storage	MWh
Q_TES_HL	MWh	Storage Thermal Losses	MWh
Q_turb_SU	MWh	Turbine Start-up Energy	MWh

21.7 Power Tower (Molten Salt)

After running simulations, SAM displays time series results for the molten salt power tower model on the Results page Tables and Time Series graphs.

Notes.

The solar radiation values (DNI) represent total energy values over the time step, and are equivalent to the values in the weather file. Temperature and wind speed values are mid-point values calculated by the weather data processor by averaging the end-of-time step wind speed from the previous time step with the end-of-time step wind speed from the current time step in the weather file.

For simulations that involve time-of-delivery pricing, results include additional variables described in Time Dependent Pricing Overview.

Hourly Data

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
Cold_tank_vol	m^3	Cold tank HTF volume	m^3
Cond_op_frac	none	Fraction of operating condenser bays	none
Cond_pressure	Pa	Condenser operating pressure	Pa
Cycle_eff	none	Power cycle efficiency	none
Cycle_power	MWh	Gross electric power output	MWh
DNI	kJ/m^2-hr	Direct normal irradiation	kJ/m^2-hr
E_net	MWh	Net electric power output	MWh
f_TC_cold	-	Thermocline: Cold depth fraction	-
f_TC_hot	-	Thermocline: Hot depth fraction	-
Field_control	none	Field operation fraction	none
Fossil_energy	MWh	Thermal energy delivered by aux backup	MWh
Fossil_fuel	MMBTU	Auxiliary heater fuel consumption	MMBTU
Hel_field_eff	none	Solar field optical efficiency	none
Hel_track_power	MWh	Heliostat drive electrical consumption	MWh
Hot_tank_vol	m^3	Hot tank HTF volume	m^3
mdot_from_storage	kg/hr	TES discharge mass flow rate	kg/hr
mdot_to_powercycle	kg/hr	Power block HTF mass flow rate	kg/hr
mdot_to_receiver	kg/hr	Receiver mass flow rate	kg/hr
mdot_to_storage	kg/hr	TES charge mass flow rate	kg/hr
Par_aux	MWh	Auxiliary heater operation parasitic load	MWh
Par_cooling_tower	MWh	Cooling system parasitic power	MWh
Par_fixed	MWh	Fixed parasitic load	MWh
Par_pipe_loss	MWh	Non-receiver piping thermal loss	MWh
Par_plant_bal	MWh	Balance of plant parasitic load	MWh
Par_recirc_htr	MWh	Receiver freeze protection energy	MWh
Par_store_pump	MWh	Power cycle/TES pumping power	MWh
Par_tank_htr	MWh	Tank freeze protection energy	MWh
Par_total	MWh	Total parasitic consumption	MWh
Power_to_receiver	MWh	Thermal energy on receiver	MWh

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
Q_from_TES	MWh	Thermal energy from thermal storage	MWh
Q_to_PB	MWh	Thermal energy to the power cycle	MWh
Q_to_TES	MWh	Thermal energy to thermal storage	MWh
Rec_conv_loss	MWh	Receiver convective loss	MWh
Rec_eff	none	Receiver thermal efficiency	none
Rec_pump_power	MWh	Receiver pumping power consumption	MWh
Rec_rad_loss	MWh	Receiver radiative loss	MWh
Rec_therm_power	MWh	Receiver thermal power output	MWh
solar_azimuth	deg	Solar azimuth angle	deg
solar_zenith	deg	Solar zenith angle	deg
T_dry_bulb	C	Dry-bulb temperature	C
T_from_powerblock	C	Power cycle HTF return temperature	C
T_rec_inlet	C	Receiver inlet HTF temperature	C
T_rec_outlet	C	Receiver outlet HTF temperature	C
T_TC_cold	C	Thermocline: Cold node temperature	C
T_TC_hot	C	Thermocline: Hot node temperature	C
T_TC_max	C	Thermocline: Maximum temperature	C
T_to_powerblock	C	Power cycle HTF inlet temperature	C
T_wb	C	Wet-bulb temperatre	C
Total_incident_power	MWh	Total incident thermal energy	MWh
Total_tank_loss	MWh	Total tank thermal losses	MWh
TOUperiod	none	Time-of-dispatch period	none
V_wind	m/s	Wind velocity	m/s
Water_makeup_flow	kg/hr	Water consumption mass flow rate	kg/hr

Monthly Data and Single Values

Monthly data file name	TRNSYS Units	Descriptive name	SAM Units
Power_from_cycle_elec	MWh	Gross Electric Output	kWh
Power_to_the_grid	MWh	Net Electric Output	kWh
Total_incident_power	MWh	Total Incident Thermal Energy	MWh
Power_from_receiver	MWh	Receiver Thermal Output	MWh
Q_to_PB	MWh	Thermal Energy to Power Block	MWh
Water_makeup_flow	MWh	Water usage	m^3

21.8 Power Tower (Direct Steam)

After running simulations, SAM displays time series results for the direct steam power tower model on the Results page Tables and Time Series graphs.

Notes.

The solar radiation values (DNI) represent total energy values over the time step, and are equivalent to the values in the weather file. Temperature and wind speed values are mid-point values calculated by the weather data processor by averaging the end-of-time step wind speed from the previous time step with the end-of-time step wind speed from the current time step in the weather file.

For simulations that involve time-of-delivery pricing, results include additional variables described in Time Dependent Pricing Overview.

Hourly Data

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
Aux_steam_flow_rate	kg/hr	Auxiliary: Mass flow rate (steam)	kg/hr
Boiler_abs	MWh	Receiver->Boiler: Absorbed thermal power	MWh
Boiler_conv_loss	MWh	Receiver->Boiler: Convective losses	MWh
Boiler_rad_loss	MWh	Receiver->Boiler: Radiative losses	MWh
Boiler_therm_eff	none	Receiver->Boiler: Thermal efficiency	none
Cond_op_frac	none	Rankine Cycle: Fraction of heat rejection system operating	none
Cond_pressure	Pa	Rankine Cycle: Condenser pressure	Pa
Cond_pressure	Pa	Rankine Cycle: Condenser pressure	Pa
Cycle_power	MWh	Rankine Cycle: Electrical power output	MWh
Defocus	none	Heliostats: Defocus	none
DNI	kJ/m^2hr	Weather Data: Direct normal radiation (not interpolated)	kJ/m^2hr
Dry_bulb_temp	C	Weather Data: Dry bulb temperature	C
Fossil_energy	MWh	Auxiliary: Thermal power delivered to cycle	MWh
Fossil_fuel	MMBTU	Auxiliary: Fuel energy delivered to aux heater	MMBTU
Hel_field_eff	none	Heliostats: Field efficiency (before controller demanded defocus)	none

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
Hel_track_power	MWh	Parasitics: Heliostat tracking power	MWh
Mass_flow_rate_frac	none	Receiver->RH: Reheater mass flow rate fraction	none
P_boiler_inlet	kPa	Receiver->Boiler: Inlet pressure	kPa
P_boiler_outlet	kPa	Receiver->Boiler: Outlet and steamdrum pressure	kPa
P_RH_in	kPa	Receiver->RH: Inlet pressure	kPa
P_RH_out	kPa	Receiver->RH: Outlet pressure	kPa
P_SH_out	kPa	Receiver->SH: Outlet pressure	kPa
Par_cooling_tower	MWh	Parasitics: Cooling tower power	MWh
Par_fixed	MWh	Parasitics: Fixed losses	MWh
Par_pipe_loss	MWh	Parasitics: Piping losses (thermal)	MWh
Par_plant_bal	MWh	Parasitics: Balance Of Plant	MWh
Par_total	MWh	Parasitics: Total parasitics	MWh
Power_to_grid	MWh	System: Power to grid	MWh
Power_to_rec_less_rad	MWh	Receiver->Comb: Power to receiver less radiation	MWh
Pres_drop_boiler	Pa	Receiver->Boiler: Pressure drop	Pa
Pres_drop_RH	Pa	Receiver->RH: Pressure drop	Pa
Pres_drop_SH	Pa	Receiver->SH: Pressure drop	Pa
Rec_conv_loss	MWh	Receiver->Comb: Total convective losses	MWh
Rec_power_preloss	MWh	Receiver->Comb: Total absorbed thermal power	MWh
Rec_pump_power	MWh	Parasitics: Receiver pumping power	MWh
Rec_rad_loss	MWh	Receiver->Comb: Total radiative losses	MWh
Rec_therm_eff	none	Receiver->Comb: Thermal efficiency	none
Rec_therm_power	MWh	Receiver->Comb: Thermal power transferred to steam	MWh
RH_abs	MWh	Receiver->RH: Absorbed thermal power	MWh
RH_conv_loss	MWh	Receiver->RH: Convective losses	MWh
RH_rad_loss	MWh	Receiver->RH: Radiative losses	MWh
RH_therm_eff	none	Receiver->RH: Thermal efficiency	none

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
SH_abs	MWh	Receiver->SH: Absorbed thermal power	MWh
SH_conv_loss	MWh	Receiver->SH: Convective losses	MWh
SH_rad_loss	MWh	Receiver->SH: Radiative losses	MWh
SH_therm_eff	none	Receiver->SH: Thermal efficiency	none
Steam_flow_rate	kg/hr	Receiver->SH: Mass flow rate	kg/hr
T_boiler_inlet	C	Receiver->Boiler: Inlet temperature	C
T_boiling	C	Receiver->Boiler: Outlet and steamdrum temperature	C
T_fw_outlet	C	Receiver->Boiler: Feedwater outlet temperature	C
T_max_boiler	C	Receiver->Boiler: Maximum boiler tube surface temperature	C
T_max_RH	C	Receiver->RH: Maximum tube surface temperature	C
T_max_SH	C	Receiver->SH: Maximum tube surface temperature	C
T_RH_in	C	Receiver->RH: Inlet temperature	C
T_RH_out	C	Receiver->RH: Outlet temperature	C
Total_incident_power	MWh	Heliostats: The total radiation incident on the field	MWh
v_exit_RH	m/s	Receiver->RH: Steam exit velocity	m/s
v_exit_SH	m/s	Receiver->SH: Steam exit velocity	m/s
V_wind	m/s	Weather Data: Wind velocity	m/s
Water_makeup_flow	kg/hr	Rankine Cycle: Makeup water flow rate	kg/hr
Wet_bulb_temp	C	Weather Data: Wet bulb temperature	C

Monthly Data and Single Values

Monthly data file name	TRNSYS Units	Descriptive name	SAM Units
Cycle_power	MWh	Gross Electric Output	kWh
Power_to_grid	MWh	Net Electric Output	kWh
Total_incident_power	MWh	Total Incident Thermal Energy	MWh
Rec_therm_power	MWh	Receiver Thermal Output	MWh

Monthly data file name	TRNSYS Units	Descriptive name	SAM Units
Water_makeup_flow	MWh	Water usage	m^3

21.9 Generic Solar System

After running simulations, SAM displays time series results for the generic solar system model on the Results page [Tables](#) and [Time Series](#) graphs.

> **Notes.**
>
> The solar radiation values (DNI) represent total energy values over the time step, and are equivalent to the values in the weather file. Temperature and wind speed values are mid-point values calculated by the weather data processor by averaging the end-of-time step wind speed from the previous time step with the end-of-time step wind speed from the current time step in the weather file.
>
> For simulations that involve time-of-delivery pricing, results include additional variables described in [Time Dependent Pricing Overview](#).

Hourly Data

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
DNI	W/m2	Direct normal irradiation	W/m2
Irr_beam_horiz	W/m2	Beam-horizontal irradiation	W/m2
Irr_tot_horiz	W/m2	Total horizontal irradiation	W/m2
T_dry_bulb	C	Dry-bulb temperature	C
T_wet_bulb	C	Wind velocity	C
TOUPeriod	none	Time-of-dispatch period	none
V_wind	m/s	Wind velocity	m/s
Hour_of_day	hour	Hour of the day	hour
Day_of_year	day	Day of the year	day
SolAlt	deg	Solar elevation angle	deg
SolAz	deg	Solar azimuth angle	deg
SF_OptEff	none	Solar field optical efficiency	none
f_SFhl_(Qdni)	none	SF load-based thermal loss correction	none
f_SFhl_(Tamb)	none	SF temp-based thermal loss correction	none
f_SFhl_(V_wind)	none	SF wind-based thermal loss correction	none
Qsf_HL	MWh	Solar field thermal losses	MWh
Qsf	MWh	Solar field delivered thermal power	MWh
Q_Irr	MWh	Solar field thermal output	MWh
Qtpb	MWh	Thermal energy to the power cycle	MWh
QTurSu	MWh	Power cycle startup energy	MWh

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
Q_to_TES	MWh	Thermal energy to storage	MWh
Q_from_TES	MWh	Thermal energy from storage	MWh
E_in_TES	MWh	Energy in thermal storage	MWh
Q_TES_HL	MWh	TES thermal losses	MWh
Q_dump_TESFull	MWh	Dumped energy from full TES	MWh
Q_dump_TESchg	MWh	Dumped energy from TES charge rate	MWh
Q_dump_uMin	MWh	Dumped energy below minimum operation	MWh
Q_dump_tot	MWh	Total dumped energy	MWh
Q_fossil	MWh	Thermal energy delivered by aux backup	MWh
Q_gas	MWh	Auxiliary heater fuel consumption	MWh
f_effpc_(Qtpb)	none	Load-based conversion efficiency correction	none
f_effpc_(Tamb)	none	Temp-based conversion efficiency correction	none
Eff_pc	none	Power cycle efficiency	none
E_gross_solar	MWh	Gross electricity output (solar only)	MWh
E_gross_fossil	MWh	Gross electricity output (fossil only)	MWh
E_gross	MWh	Gross electric power output	MWh
E_par_fixed	MWh	Fixed parasitic load	MWh
E_par_prod	MWh	Production-based parasitic load	MWh
E_parasit	MWh	Total parasitic consumption	MWh
E_par_Online	MWh	Parasitics consumed while plant is online	MWh
E_par_Offline	MWh	Parasitics consumed while plant is offline	MWh
Enet	MWh	Net electric power output	MWh

Monthly Data and Single Values

Monthly data file name	TRNSYS Units	Descriptive name	SAM Units
E_gross	MWh	Gross Electric Output	kWh
Enet	MWh	Net Electric Output	kWh
Qsf	MWh	Solar Field Thermal Output	MWh
Qtpb	MWh	Thermal Energy to Power Block	MWh
Q_to_TES	MWh	Thermal Energy to Storage	MWh
Q_from_TES	MWh	Thermal Energy from Storage	MWh
Qsf_HL	MWh	Solar Field Thermal Losses	MWh

Monthly data file name	TRNSYS Units	Descriptive name	SAM Units
Q_TES_HL	MWh	Storage Thermal Losses	MWh
Q_dump_tot	MWh	Total Dumped Thermal Energy	MWh
QTurSu	MWh	Turbine Start-up Energy	MWh
Q_fossil	MWh	Aux. Fuel Consumption	MWh

21.1 Linear Fresnel 0

After running simulations, SAM displays time series results for the linear fresnel model on the Results page Tables and Time Series graphs.

Notes.

The solar radiation values (DNI) represent total energy values over the time step, and are equivalent to the values in the weather file. Temperature and wind speed values are mid-point values calculated by the weather data processor by averaging the end-of-time step wind speed from the previous time step with the end-of-time step wind speed from the current time step in the weather file.

For simulations that involve time-of-delivery pricing, results include additional variables described in Time Dependent Pricing Overview.

Monthly Data and Single Values Data

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
eNet	kWh	Net energy	kWh
DNI	W/m2	Direct normal irradiation	W/m2
V_wind	m/s	Wind velocity	m/s
T_dry_bulb	C	Dry bulb temperature	C
T_wet_bulb	C	Wet bulb temperature	C
P_atm	atm	Atmospheric pressure	atm
RelHumidity	none	Relative humidity	none
SolarAlt	deg	Solar elevation angle	deg
SolarAz	deg	Solar zenith angle	deg
cond_bays_frac	none	Fraction of operating condenser bays	none
defocus_frac	none	Field operation fraction	none
eta_opt_ave	none	Collector optical efficiency	none
eta_thermal	none	Solar field thermal efficiency	none
eta_sf_tot	none	Total solar field collection efficiency	none
eta_cycle	none	Cycle conversion efficiency	none
m_dot_aux	kg/hr	Auxiliary heater mass flow rate	kg/hr
m_dot_field	kg/hr	Flow rate from the field	kg/hr

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
m_dot_b_tot	kg/hr	Flow rate within the boiler section	kg/hr
m_dot_to_pb	kg/hr	Flow rate to the power block	kg/hr
m_dot_loop	kg/s	Flow rate in a single loop	kg/s
m_dot_makeup	kg/hr	Water makeup flow rate	kg/hr
Pres_condenser	Pa	Condenser pressure	Pa
Pres_turb_inlet	bar	Pressure at the turbine inlet	bar
Pres_field_inlet	bar	Pressure at the solar field inlet	bar
dP_tot	bar	Total solar field pressure drop	bar
q_loss_piping	MWh	Solar field piping heat loss	MWh
q_aux_fluid	MWh	Power delivered by aux heater	MWh
q_aux_fuel	MMBTU	Heat content of fuel required to provide aux firing	MMBTU
q_startup	MWh	Startup energy consumed	MWh
q_dump	MWh	Dumped thermal energy	MWh
q_field_delivered	MWh	Solar field thermal power	MWh
q_inc_tot	MWh	Total power incident on the field	MWh
q_loss_rec	MWh	Total receiver thermal losses	MWh
q_loss_sf	MWh	Total solar field thermal losses	MWh
q_to_pb	MWh	Thermal energy to the power block	MWh
T_cycle_out	C	Power cycle steam return temperature	C
T_field_in	C	Solar field steam inlet temperature	C
T_loop_out	C	Collector loop outlet temperature	C
T_field_out	C	Solar field outlet temperature	C
T_pb_in	C	Power cycle inlet temperature	C
W_dot_aux	MWh	Aux boiler parasitic power	MWh
W_dot_bop	MWh	Load dependent parasitic power	MWh
W_dot_col	MWh	Collector field parasitic power	MWh
W_dot_fixed	MWh	Fixed parasitic power	MWh
W_dot_pump	MWh	Parasitic pumping power	MWh
W_dot_par_cool	MWh	Cooling system parasitic load	MWh
W_dot_gross	MWh	Gross cycle power output	MWh
W_dot_net	MWh	Net plant power output	MWh

Monthly Data

Monthly data file name	TRNSYS Units	Descriptive name	SAM Units
m_dot_makeup	kg	Water makeup flow rate	kg
q_loss_piping	MW-hr	Solar field piping heat loss	MW-hr
q_aux_fluid	MW-hr	Power delivered by aux heater	MW-hr
q_aux_fuel	MMBTU	Heat content of fuel required to provide aux firing	MMBTU
q_dump	MW-hr	Dumped thermal energy	MW-hr
q_field_delivered	MW-hr	Solar field thermal power	MW-hr
q_inc_tot	MW-hr	Total power incident on the field	MW-hr
q_loss_rec	MW-hr	Total receiver thermal losses	MW-hr
q_loss_sf	MW-hr	Total solar field thermal losses	MW-hr
q_to_pb	MW-hr	Thermal energy to the power block	MW-hr
W_dot_aux	MW-hr	Aux boiler parasitic power	MW-hr
W_dot_bop	MW-hr	Load dependent parasitic power	MW-hr
W_dot_col	MW-hr	Collector field parasitic power	MW-hr
W_dot_fixed	MW-hr	Fixed parasitic power	MW-hr
W_dot_pump	MW-hr	Parasitic pumping power	MW-hr
W_dot_par_cool	MW-hr	Cooling system parasitic load	MW-hr
W_dot_gross	MW-hr	Gross cycle power output	MW-hr
W_dot_net	MW-hr	Net plant power output	MW-hr

21.11 Dish Stirling

After running simulations, SAM displays time series results for the dish stirling model on the Results page Tables and Time Series graphs.

Notes.

The solar radiation values (DNI) represent total energy values over the time step, and are equivalent to the values in the weather file. Temperature and wind speed values are mid-point values calculated by the weather data processor by averaging the end-of-time step wind speed from the previous time step with the end-of-time step wind speed from the current time step in the weather file.

For simulations that involve time-of-delivery pricing, results include additional variables described in Time Dependent Pricing Overview.

Hourly Data

Hourly data file name	TRNSYS Units	Descriptive name	SAM Units
T_amb_C	C	Ambient Temperature	C
wind_speed_out	m/s	Wind Speed	m/s
DNI	W/m^2	DNI	W/m^2
Power_in_Collector	MW	Power Incident on Collector	MW
Power_out_col	MW	Power from the collector dish	MW
Power_in_Receiver	MW	Power entering receiver from the collector	MW
Power_out_Rec	MW	Receiver Output Power	MW
P_out_SE	MW	Stirling Engine Gross Output	MW
Net_Dish_Field_Power	MW	Net_Dish_Field_Power	MW
Net_system_efficiency	none	Net System Efficiency	none
phi_shade	none	Dish-to-Dish shading performance factor	none
Collector_Losses	MW	Total Collector Losses	MW
eta_Collector	none	Collector Efficiency	none
P_Rec_losses	MW	Total Receiver Losses	MW
eta_Receiver	none	Receiver Thermal Efficiency	none
T_heater_head_operate	K	Receiver head operating temperature	K
Stirling_Engine_Losses	none	Stirling Engine Losses	none
Stirling_Engine_Efficiency	none	Stirling Engine Efficiency	none
engine_pressure	Pa	Engine Pressure	Pa
P_parasitic	MW	Total Parasitic Load	MW
T_compression_C	C	Cold Sink Temperature / Compression Temperature	C
temp_into_radiator	C	Cooling Fluid Temp to Cold Sink	C
temp_out_of_radiator	C	Cooling Fluid Temp from Cold Sink	C

Monthly Data and Single Values

Monthly data file name	TRNSYS Units	Descriptive name	SAM Units
Power_in_Coll_Field	MWh	Total Field Power Incident on Collector	MWh
Power_out_Coll_Field	MWh	Total Field Power from the Collector	MWh
Power_in_Receiver_Field	MWh	Total Field Receiver Inlet Power from the collector	MWh
Receiver_Power_Out_Field	MWh	Total Field Receiver Power Output	MWh
Gross_Field_Power	MWh	Total Field Stirling Engine Gross Power Output	MWh
Net_Field_Power	MWh	Total Field Net Power Output	MWh

21.1 2 Solar Water Heating

After running simulations, SAM displays hourly results for the solar water heating model on the Results page Tables and Time Series graphs.

Notes.

For simulations that involve time-of-delivery pricing, results include additional variables described in Savings and Revenue.

Variable Name	Units	Description
Hourly Energy Delivered	kWh	Energy saved by the solar water system, adjusted by the values you specify on the Performance Adjustment Page.
Q delivered	kWh	Thermal energy delivered by the solar water heating system.
Q saved	kWh	Electric energy saved by the solar water heating system: $Q_{saved} = Q_{aux,only} - Q_{aux} - P_{pump}$. This value is equivalent to the energy delivered by the solar water heating system.
Draw – hot water	kg/hr	The hourly usage of hot water specified in the draw profile on the input page.
Irradiance - Beam	W/m2	Direct normal radiation value from the weather file.
Irradiance - Diffuse	W/m2	Diffuse horizontal radiation value from the weather file.
Irradiance - Incident	W/m2	The total hourly incident global radiation incident on the collector.
Irradiance - Transmitted	W/m2	The total hourly radiation that makes it into the collector. Depends on the optical properties of the

Variable Name	Units	Description
		collector.
Operation mode		1 – mixed mode, during hours when useful energy is collected 2 – stratified mode, during hours no useful energy is collected.
P pump	kWh	The total amount of electric pump power needed to drive the collector loop and heat exchanger loop.
Q auxiliary	kWh	Electricity energy required by the auxiliary heater to raise the water temperature from the solar storage tank to the set temperature: $Q_{aux} = \dot{m}_{draw} C_p (T_{set} - T_{deliv})$, where T_{deliv} is the temperature of the water delivered from the solar tank. Because solar heat has been added to the water, $T_{deliv} > T_{mains}$, and less energy is needed to bring the water to the desired set temperature than would be required without the solar water heating system.
Q auxiliary only	kWh	Electric energy that would be required without the solar water heating system: $Q_{aux,only} = \dot{m}_{draw} C_p (T_{set} - T_{mains})$.
Q loss	kWh	Envelope loss to room: $Q_{loss} = UA_t (T_{tank} - T_{room})$.
Q transmitted	kWh	Solar radiation transmitted through the collector glass, accounting for collector area: $Q_{transmitted} = I_{transmitted} * A_c$, where Itransmitted is the transmitted irradiance and Ac is the total collector area.
Q useful	kWh	Energy delivered by the collector to the solar water storage tank.
T ambient	C	The mid-hour ambient temperature calculated by the weather data processor by averaging the end-of-hour temperature from the previous hour with the end-of-hour temperature from the current hour in the weather file.
T cold	C	The temperature of the cold portion of the solar storage tank volume during stratified mode (Operation mode = 2). If the tank is not stratified (Operation mode = 1), this value is equal to the previous hour's cold temperature.
T delivered	C	The temperature of the water delivered from the storage tank.
T hot	C	The temperature of the hot portion of the solar storage tank volume during stratified mode

Variable Name	Units	Description
		(Operation mode = 2). If not stratified (Operation mode = 1), this value is equal to the previous hour's hot temperature.
T mains	C	The temperature of water incoming from the supply source.
T tank	C	The mean temperature of the solar storage tank.
V cold	m3	The estimated volume of the cold portion of the solar storage tank, where "cold" is with respect to the hot portion of the tank. SAM models the hot and cold portions as separate nodes. The cold volume increases as users draw water from the tank and mains water replaces it.
V hot	m3	The estimated volume of the hot portion of the solar storage tank, where "hot" is with respect to the cold portion of the tank. SAM models the hot and cold portions as separate nodes. The hot volume increases from hour to hour as the useful energy from the collector is added until the hot volume is equal to the tank volume (and cold volume is zero).

21.13 Geothermal

After running simulations, SAM displays time series results for the Geothermal performance model on the Results page Tables and Time Series graphs.

The geothermal model calculates several values quantifying the electricity generated by the system. Some of the values are results of the performance model, and do not include the effects of the adjustment factors on the Performance Adjustment page, while others are results of the financial model and do include those effects.

Annual Energy

The electricity generated by the system in the project's first year.

Energy (kWh)

an output of the finance model. Right now it's (output from performance model summed annually) * (System Output Adjustments) * (System Output Adjustments), but I expect that to change.

Monthly Energy (kWh)

The electricity generated by the system in each month of the analysis period. If you choose the **Power Block Hourly** option on the Power Block page, this value is the sum of the hourly values for each month.

Monthly Energy Delivered (kWh)

an output of the finance model. I think it's (output from performance model) * (System Output

Adjustments)

Monthly Power (kW)

output of the performance model. The average power (kW) over the month.

Power in each time step (kW)

output of the performance model. If this is a monthly analysis, then it should match "Monthly Power." If it's an hourly analysis, then this is the average power in each hour (which will match the hourly energy... 5 kW for 1 hour = 5 kWh)

Hourly Energy (kWh)

The electricity generated by the system in each hour, before adjustment factors from the Performance Adjustment page are applied. If you choose the **Power Block Monthly** option on the Power Block page, then it is the system's monthly output divided by the number of hours in the month.

Hourly Energy Delivered (kWh)

The **Hourly Energy** values described above, after adjustment factors from the Performance Adjustment page are applied.

22 Savings and Revenue

SAM reports Revenue results for PPA projects (utility financing options), and Savings results for retail projects (residential and commercial financing options).

For PPA projects, the revenue depends on the electricity sales price and the quantity of energy generated by the system. SAM assumes a fixed electricity sales price (PPA price) with a set of optional TOD factors on Time of Delivery Factors page, or on the Thermal Energy Storage page for Concentrating Solar Power projects.

For retail projects, savings depends on the electric rate structure from the Utility Rates page, the quantity of electricity generated by the system, and the electricity usage from the Electric Load page.

The Time Dependent Pricing Topics are:

- Time Dependent Pricing Overview
- PPA Revenue with TOD Factors
- Retail Electricity Savings

22.1 Time Dependent Pricing Overview

SAM can model PPA price time-of-delivery (TOD) factors or retail time-of-use (TOU) rates.

For a description of simulation results for the two types of time-dependent pricing, see

- PPA Revenue with TOD Factors

- Retail Electricity Savings

For an overview of the two kinds of time-dependent pricing, see the descriptions below.

PPA Price

Power generation projects sell all of the electricity that the system generates at a price negotiated through a power purchase agreement (PPA). For these projects, SAM allows you to define an optional set of up to nine time-of-delivery (TOD) factors to adjust the power price in any given hour of the year.

Depending on the **Solution Mode** option you choose on the Financing page, you can either specify the PPA price as an input on the Financing page, or SAM can calculate a PPA price based on a target IRR that you specify on the Financing page. In either case, the actual power price in each hour is the product of the PPA price and the TOD factor that applies for that hour.

Note. The TOD factors are not suitable for modeling real time pricing because you can only specify up to nine TOD factors.

The TOD factors are available for each of the six financing options that involve PPA prices. For those options, you specify the PPA price (or target IRR) and other financial parameters on the Financing page:

- Commercial PPA
- Utility IPP
- Utility Single Owner
- Utility All Equity Partnership Flip
- Utility Leveraged Partnership Flip
- Utility Sale Leaseback

You specify the TOD factors and time that they apply on one of the following input pages:

- Time of Delivery Factors page for photovoltaic, wind, geothermal, and biomass projects.
- The Thermal Energy Storage page for the concentrating solar power technologies: Physical trough, empirical trough, molten salt power tower, and generic solar system.

After running simulations, SAM displays TOD-related results on the Results page. See PPA Revenue with TOD Factors for details.

Retail Price for Residential and Commercial Financing

Electricity generated by the system for residential and commercial projects meets an electric load for a building or facility. The project sells any electricity generated by the system in excess of the load at a retail sell rate, and buys any electricity required from the grid to meet the load at a retail buy rate. The buy and sell rates and other fees depend on the rate structure defined on the Utility Rate page.

The value of the electricity generated by the system over a given period depends on several factors:

- The load that you specify on the Electric Load page.
- The rate structure that you specify on the Utility Rate page.
- Quantity of energy generated by the system.

After running simulations, SAM displays TOD-related results on the Results page. See Retail Electricity Savings for details.

22.2 PPA Revenue with TOD Factors

This topic describes the time-of-delivery (TOD) variables available on the Results page after you run simulations for a PPA project that involves time-dependent pricing.

SAM reports hourly, monthly, and annual TOD-related results.

Note. When you include TOD factors in your analysis, the PPA price in the Metrics table represents the bid price, and is different from the annual PPA Price or Energy Price reported in the Cash Flows table.

Single Values

The single value variables are available on the Results page in Graphs and Tables.

First Year TOD*n* Energy

The total quantity of electricity delivered to the grid (and sold) by the system in Year one for each of the nine TOD periods, in kWh per year.

First Year TOD*n* Energy Price

The power price for each of the nine TOD periods, equal to the product of the TOD factor for each period and the PPA price shown in the Metrics table.

First Year TOD*n* Revenue

The dollar value of electricity sold by the project in Year one for each of the nine TOD periods, in dollars per year.

Monthly Data

The monthly variables are available on the Results page in Graphs and Tables.

First Year TOD Energy by Month

The total quantity of electricity delivered to the grid (and sold) by the system in Year one for each month, in kWh. This value is equivalent to monthly energy.

First Year TOD Revenue by Month

Total dollar value of electricity sold by the project in Year one for each month.

First Year TOD*n* Energy by Month

The total quantity of electricity delivered to the grid (and sold) by the system for each month of Year one for each of the nine TOD periods, in kWh per month.

First Year TOD*n* Revenue by Month

Total dollar value of electricity sold by the project for each month of Year one for each of the nine TOD periods, in dollars per month.

Annual Data (All Years)

The annual variables are available on the Results page in Graphs as "All Years" and Tables as "Annual Data".

Note. The first row in the annual data table is equivalent to Year zero in the project cash flow.

Energy dispatched in period n

The total amount of electricity delivered to the grid (and sold) by the system in each year of the analysis period (from the Financing page) for each of the nine TOD periods.

Revenue generated in period n

The total dollar value of electricity sold by project in each year of the analysis period (from the Financing page) for each of the nine TOD periods.

Hourly Variables

The hourly variables are available on the Results page in the Tables and Time Series graphs.

Hourly Dispatch Factors

The TOD factors by hour as defined by the up to 9 TOD periods and the weekday and weekend schedules that you specify as described above either on the Time of Delivery Factors page, or for CSP systems, on the Thermal Storage page.

22.3 Retail Electricity Savings

For projects with the residential or commercial financing option (not including commercial PPA) that buy and sell electricity at retail rates, you specify a rate structure (net metering, energy rates, demand charges, and monthly charges) on the Utility Rate page, and a building or facility load on the Electric Load page. SAM assumes that electricity generated by the system serves the load. The project sells electricity generated by the system that exceeds the load, and buys electricity required from the grid to meet the load. The buy and sell rates depend on the rate structure rate for when the system output is less than the load.

SAM reports hourly, monthly, and annual time electricity rate results in the tables and graphs on the Results page.

> **Note.** If SAM reports zeroes for rates or charges in the variables described below where you expect to see non-zero values, it is possible that you are modeling a system with no electric load, which means that all electricity generated by the system is delivered to the grid at the sell rate that applies in each hour that electricity is generated.

Inflation and Escalation Rate

SAM reports some results as "Year 1" values, representing values in the first year of the project cash flow. To calculate Year two and later values, SAM applies both the inflation rate from the Financing page and the escalation rate from the Utility Rate page to the Year one rates that you specify on the Utility Rate page. For example, if you specify a fixed monthly charge $6.5/month, an inflation rate of 2.5%, and an escalation rate of 0.5%, the monthly charge will be $6.5/month in Year one, $6.695/month in Year 2, $6.89585/month in Year 3, etc. (SAM does not apply the inflation rate to sales and purchases when you use an annual schedule to specify different escalation rates for different years.)

Energy and Power Units

SAM reports hourly, monthly, and annual electricity values in kilowatt-hours (kWh), representing a total quantity of electricity over each period. Because the units for hourly electricity values are effectively kilowatt-hour per hour (kWh/h) values, they may also be expressed in kilowatt (kW). However, to avoid confusion, units for hourly energy values are shown below as kWh/h.

SAM reports hourly peak electricity values in kilowatts (kW). For simulations using hourly load data, the peak and total electricity values are the same. For simulations using sub-hourly load data (15-minute, 10-minute, 1-minute), the peak value will not be the same as the total hourly value. SAM uses the peak electricity values to determine peak monthly values for demand charge calculation. For example, for hourly load data, the monthly peak value will be an hourly value, for 15-minute load data, the monthly peak value will be a 15-minute value.

Monthly Data

The monthly data shows the first year values by month. The monthly variables are available on the Results page in Graphs and Tables.

Note. To see how monthly data changes from year to year for a given month, in Tables, display the Annual Data, and choose the variable and month.

Monthly Energy (kWh)

The total amount of electricity generated by the system in each month.

Year 1 monthly demand charge (fixed) [with/without] system($)

The demand charge for each month of Year one that results from the demand charges defined in the **Fixed or Tiered Monthly Demand Charges** table on the Utility Rate page.

Year 1 monthly demand charge (TOU) [with/without] system($)

The demand charge for each month of Year one that results from the demand charges defined in the **Time-of-use or Tiered Time-of-use Demand Charges** table on the Utility Rate page.

Demand Charge Notes.

The "with system" value is for the load and rate structure with the renewable energy system, and the without system value is for the same load and rate structure without the system.

SAM does not report the fixed monthly charge from the Utility Rate page in the Monthly results. Be sure to account for that value when you calculate monthly costs.

You can see the total monthly costs in the hourly results **Year 1 hourly sales/purchases** variable (see below). They appear in the last hour of each month:

Date	Hour
Jan 31	744
Feb 28	1416
Mar 31	2160
Apr 30	2880
May 31	3624
Jun 30	4344
Jul 31	5088
Aug 31	5832
Sep 30	6552
Oct 31	7296
Nov 30	8016
Dec 31	8760

Year 1 monthly electric load (kWh)

The total amount of electricity required by the building or facility in each month.

Year 1 monthly electricity to/from grid (kWh)

The total amount of electricity delivered to the grid (positive number) or required from the grid (negative number).

Year 1 monthly net metering electricity credit (kWh)

The credit earned this month for electricity generated by the system in excess of the load to be applied to the next month's electric bill. These values only apply when net metering is enabled on the Utility Rate page.

Year 1 monthly sales/purchases with system ($)

The total sales (positive value) or purchases (negative value) of electricity in each month, including fixed monthly charges and demand charges.

Hourly Data

SAM reports hourly results for the project's first year on the Results page in the Tables and Time Series graphs. These variables appear with the prefix "Year 1."

Year 1 Values and Cash Flow Calculations

If you specify a **Year-to-year decline in output** factor of one on the Performance Adjustment page, SAM assumes that the system's hourly generation profile is the same from year to year. In that case, the amount of electricity sold to and purchased from the grid will also be the same from year to year. If you specify a different value for the **Year-to-year decline in output** factor, SAM uses the factor to adjust the system's hourly output values in years two and later.

Similarly, for electricity rates, SAM increases the rates from year to year based on the inflation rate on the Financing page, and the escalation rate on the Utility Rate page.

Hourly Energy (kWh)

The electricity generated by the system in each hour.

Hourly demand charge TOU period

The demand charge period number that applies to each hour defined in the **Time-of-use or Tiered Time-of-use Demand Charges** Weekday and Weekend matrices on the Utility Rate page.

Hourly energy charge TOU period

The energy charge period number that applies to each hour defined in the **Time-of-use and Tiered Energy Rates** Weekday and Weekend matrices on the Utility Rate page.

Year 1 hourly electricity to/from grid (kWh)

The quantity of electricity delivered to the grid (positive value) or purchased from the grid (negative value) in each hour.

Year 1 hourly electric load (kWh)

The quantity of electricity required by the building or facility in each hour.

Year 1 hourly sales/purchases [with/without] system ($)

The value of electricity delivered to the grid (positive) or purchased to the grid (negative) in each hour. For a rate structure with net metering, sales and purchases are calculated on a monthly basis (see above), so the hourly values are all zeros.

Year 1 subhourly peak to/from grid (kW)

Applies only when you specify sub-hourly load data on the Electric Load page. The maximum value of the sub-hourly electricity at grid values for each hour. Negative values indicate electricity from the grid, positive values indicate electricity to the grid.

23 Software Development Kit (SDK)

The SAM Simulation Core (SSC) software development kit is a collection of developer tools for creating renewable energy system models using the SSC library. SAM is a desktop application that provides a user-friendly front end for the SSC library. The SDK allows you to create your own applications using the SSC library.

To download the SSC SDK, visit the SAM website SDK page.

Note. The SSC SDK is under development at the time of this SAM release (mid-January 2013). It replaces the Code Generation feature that was part of earlier SAM versions.

The SDK includes the following:

- The SSC Guide explaining how to use the tools in the SDK.
- The SSC API.
- The SSCdev development environment to explore SSC modules and build test models.

A set of libraries for the following operating systems:

- Windows 32-bit
- Windows 64-bit
- OS X 64-bit
- Linux 64-bit

A set of wrappers for the following languages:

- C#
- Java
- MATLAB
- Python

Code examples.

24 SamUL Scripting Language

SamUL is a scripting language that you can use to automate simulation runs in SAM.

For a more detailed reference information, see the following topics:

- Writing and Running SamUL Scripts describes the steps to create a script.
- Why use SamUL? provides a context for the scripting language.
- Data Variables describes variable naming conventions, syntax, and data types.
- Flow Control describes comparison operators, if-then statements, loops, and quitting.
- Arrays of Data explains how to work with arrays of data in SamUL.
- Function Calls explains how to work with functions.
- Input, Output, and System Access explains how to work with text files, user prompts, and other programs for inputs and outputs to SamUL.
- Interfacing with SAM Analyses explains how to use SamUL to control SAM simulations with examples.
- Code Sample: Latin Hypercube Sampling is a sample script.
- Library Reference lists the SamUL functions with their parameters.

24.1 Writing and Running SamUL Scripts

A SamUL script is code that you write in a SAM file. SAM stores the script in the file along with cases representing the power projects you are modeling.

For examples of SamUL scripts, see the following sample files. On the File menu, click **Open Sample File** and choose one of the following the files from the list:

- SamUL Samples
- SamUL Weather Data Case Study
- SamUL Weather Uncertainty Analysis
- Power Tower Field Optimization with SamUL

To create a SamUL script:

1. Create or open a SAM file with at least one case.
2. On the **Script** menu, click **New SamUL Script**.

   SAM creates a new tab for the SamUL development environment where you write, edit, and run the script.

The SamUL development environment consists of a toolbar, editor, and console:

- The toolbar at the top of the window provides controls for running and saving scripts, adding commands and variables, and for finding text in the script.
- The editor is where you write and edit the script.
- The console at the bottom of the window displays script outputs and error messages when you run the script.

SAM recognizes the file extension .sul as a text file containing a SamUL script. Use the toolbar buttons to save and open .sul files:

> **Note.** SAM saves the SamUL script in the .zsam file where you created the script. You do not need to save the script to an .sul file unless you want to use it in a different .zsam file.

To run a script in a SAM file, there must be at least one case the file. In the script, you specify the name of a case with the SetActiveCase function, and write code to change values of inputs variables in the case, configure and run simulations, and write simulation outputs to the console or a text file.

The following simple script displays the total annual output and levelized cost of energy of a PV system for a range of five array tilt values. The script uses an input prompt to get a latitude value.

To write and run a simple SamUL script:

1. Start SAM and create a case using the Photovoltaics, PVWatts option with Residential financing. Use the default case name "New PVWatts Case 1."
2. On the **Developer** menu, click **New SamUL Script**.

   SAM adds a script and creates a tab for your script with the label Script1.
3. Click **Script Functions** to open the function browser and choose **Set Active Case**.

   The function library is a list of the SamUL functions.
4. Type an open parentheses immediately after the SetActiveCase function to display the function

syntax and a brief description.

```
SetActiveCase(
SetActiveCase ( STRING:Case name ):NONE
Sets the active case.
```

5. Type the name of the case in quotations "New PVWatts Case" and close the parentheses.
6. On the next line, use the function browser to add the GetInput function to the script.
7. Type an open parenthesis, and click **Input variables** to open the input variable browser to find the climate.location variable.
8. Use the toolbar to find the functions and variables and to write the rest of the script shown below.

New PVWatts Case 1 | Script 1

Run script | Find and replace | Save as... | Import...

```
' SamUL Script Created: Mon Apr 04 13:57:57 2011 by SamUL Script Writer

SetActiveCase("New PVWatts Case 1")

location = GetInput("climate.location")
latitude = In("Weather file is " + location + "\nEnter the latitude:")

OutLn("Tilt (degrees), Output (kWh), LCOE (cents/kWh)")

step = 5
For (i=-2; i<=2; i=i+1)
    tilt = latitude - i * step
    SetInput("pvwatts.tilt", tilt)
    Simulate()
    annual_output = GetOutput("sv.annual_output")
    lcoe = GetOutput("sv.lcoe_nom")
    OutLn(tilt + ", " + annual_output + ", " + lcoe)
end
```

9. Click **Run Script**.

   SAM displays the script output in the console, and a message in the status bar at the bottom of the window.

```
Tilt (degrees), Output (kWh), LCOE (cents/kWh)
35, 6461.45, 16.5824
30, 6466.82, 16.5687
25, 6430.91, 16.6612
20, 6354.74, 16.8609
15, 6237.32, 17.1783
```

Success. (3.31 sec)

24.2 Why use SamUL?

The SAM User Language (SamUL) is a built-in scripting language that allows a user to automate tasks and perform more complex analyses directly from within SAM. This guide assumes some rudimentary facility with basic programming concepts and familiarity with the SAM interface, capabilities, and general work flow.

Why use SamUL?

Suppose you are an energy analyst, and want to calculate the levelized cost of energy (LCOE) for several hundred locations in the United States for a specific PV system of a given size, installation costs, and financial assumptions. You are familiar with the SAM, and have access to weather data for all the requested locations.

The first step would be to set up a case for the PV system with appropriate input values. Next, you could run a simulation for each weather file individually, and record the results in a spreadsheet. You could even set up many locations in a parametric simulation. Either method would be tedious and error prone for the several hundred locations. Furthermore, if you decided to change even just one specification of the system, you would have to start all over. Automating the process would minimize errors and allow the flexibility of modifying inputs.

SamUL, SAM's built in scripting language allows you to perform this task in just a few lines of code. Once you've written the script, you can easily make changes to the assumptions in the base case, or modify the script. Because the scripting language is built in to SAM you do not need a software development environment or compiler to use it.

To get started using SamUL, see Write a Simple SamUL Script. For a more detailed reference information, see the following topics:

- Data Variables
- Flow Control
- Arrays of Data
- Function Calls
- Input, Output, and System Access
- Interfacing with SAM Analyses
- Library Reference

Why SamUL instead of VBA?

Since SamUL is so similar in functionality and syntax to Visual Basic, you might wonder why we didn't simply put a VBA engine behind SAM. Visual Basic for Applications (VBA) is a closed source Microsoft product that is very tightly integrated into the Office suite of applications, and while there are some freely available interpreters for subsets of VB-like languages, we decided that engineering a simple scripting language would be straightforward enough. In the future, we might consider integrating other well known languages, such as Lua.

In general, SamUL is close enough to VBA in syntax and structure to make it easily understandable by people familiar with VBA. By developing our own script engine, we have been able to integrate it very tightly into the SAM environment for maximum ease of use.

Some notable points distinctions include:

- 'for' loop syntax follows the C / Perl convention

- Array arithmetic is automatically performed element by element
- 'elseif' statement formatting is similar to PHP
- No distinction between functions and procedures

24.3 Data Variables

General Syntax

In SamUL, a program statement is generally placed on a line by itself, and the end-of-line marks the end of the statement. Currently, there is no facility to split a long statement across multiple lines.

Blank lines may be inserted between statements. While they have no meaning, they can help make a script easier to read. Spaces can also be added or removed nearly anywhere, except of course in the middle of a word. The following statements all have the same meaning.

```
out("Hello 1\n")
 out ("Hello 2\n")
out ( "Hello 3\n" )
```

Comments are lines in the program code that are ignored by SamUL. They serve as a form of documentation, and can help other people (and you!) more easily understand what the script does. Comments begin with the single-quote ' character, and continue to the end of the line.

```
' this program creates a greeting
out( "Hello, world!\n" ) ' display the greeting to the user
```

Variables

Variables store information while your script is running. SamUL variables share many characteristics with other computer languages.

- Variables do not need to be declared in advance of being used
- There is no distinction between variables that store text and variables that store numbers
- Variable names may contain letters, digit, and the underscore symbol. A limitation is that variables cannot start with a digit. Unlike some languages such as C and Perl, SamUL does not distinguish between upper and lower case letters in a variable (or subroutine) name. As a result, the name `myData` is the same as `MYdata`.
- Values are assigned to variables using the equal sign =. Some examples are below:

```
Num_Modules = 10
ArrayPowerWatts = 4k
Tilt = 18.2
system_name = "Super PV System"
Cost = "unknown"
COST = 1e6
cost = 1M
```

Assigning a value to a variable overwrites its previous value. As shown above, decimal numbers can be written using scientific notation or engineering suffixes. The last two assignments to Cost are the same value.

Recognized suffixes are listed in the table below. Suffixes are case-sensitive, so that SamUL can distinguish between m (milli) and M (Mega).

Name	Suffix	Multiplier
Tera	T	1e12
Giga	G	1e9
Mega	M	1e6
Kilo	k	1e3
Milli	m	1e-3
Micro	u	1e-6
Nano	n	1e-9
Pico	p	1e-12
Femto	f	1e-15
Atto	a	1e-18

Arithmetic

SamUL supports the four basic operations +, -, *, and /. The usual algebraic precendence rules are followed, so that multiplications and divisions are performed before additions and subtractions. Parentheses are also understood and can be used to change the default order of operations. Operators are left-associative, meaning that the expression 3-10-8 is understood as (3-10)-8.

More complicated operations like raising to a power and performing modulus arithmetic are possible using built-in function calls in the standard SamUL library.

Examples of arithmetic operations:

```
battery_cost = cost_per_kwh * battery_capacity

' multiplication takes precedence
degraded_output = degraded_output - degraded_output * 0.1

' use parentheses to subtract before multiplication
cash_amount = total_cost * ( 1 - debt_fraction/100.0 )
```

Simple Input and Output

You can use the built-in out and outln functions to write data to the console window. The difference is that outln automatically appends a newline character to the output. To output multiple text strings or variables, use the + operator, or separate them with a comma.

```
array_power = 4.3k
array_eff = 0.11
outln("Array power is " + array_power + " Watts.")
outln("It is " + (array_eff*100) + " percent efficient.")
outln("It is ", array_eff*100, " percent efficient.") ' same as above
```

The console output generated is:

```
Array power is 4300 Watts.
It is 11 percent efficient.
```

Use the in function to read input from the user. You can optionally pass a message to in to display to the user when the input popup appears. The user can enter either numbers or text, and SamUL will perform any type conversions if needed (and if possible).

```
cost_per_watt = in("Enter cost per watt:") ' Show a message. in() also is fine.
notice( "Total cost is: " + cost_per_watt * 4k + " dollars") ' 4kW system
```

The notice function works like out , except that it displays a pop up message box on the computer screen.

Data Types and Conversion

SamUL supports four basic types of data, although most conversions between types happen automatically. Because of this, SamUL is generally a weakly typed language, meaning that you can add text variables to number variables, and SamUL will try to make a appropriate conversion in context.

Type	Conversion Function	Valid Values
Integer Number	integer()	+/- approx. 2 billion
Double-precision Decimal Number	double()	1e-308 to 1e308, with infinity
Boolean	boolean()	true or false (1 or 0)
Text Strings	string()	Any length text string

Sometimes you have two numbers in text strings that you would like to multiply. This can happen if you read data in from a text file on the computer, for example. Since it does not make sense to try to multiply text strings, you need to first convert the strings to numbers. To convert a variable to a double-precision decimal number, use the double function, as below.

```
a = "3.5"
b = "-2"
c1 = a*b ' this will cause an error when you click 'Run'
c2 = Double(a) * Double(b) ' this will assign c2 the number value of -7
```

The assignment to c1 above will cause the error Error: Invalid string operator '*', while the assignment to c2 makes sense and executes correctly.

You can also use integer to convert a string to an integer or truncate a decimal number, or the string function to explicitly convert a number to a string variable.

If you need to find out what type a variable currently has, use the typeof function to get a description.

```
a = 3.5
b = -2
c1 = a+b ' this will set c1 to -1.5
c2 = String( Integer(a) ) + String( b ) ' c2 set to text "3-2"

outln( typeof(a) ) ' will display "double"
outln( typeof(c2) ) ' will display "string"
```

Special Characters

Text data can contain special characters to denote tabs, line endings, and other useful elements that are not part of the normal alphabet. These are inserted into quoted text strings with escape sequences, which begin with the \ character.

Escape Sequence	Meaning
\n	New line
\t	Tab character
\r	Carriage return
\"	Double quote
\\	Backslash character

So, to print the text "Hi, tabbed world!", or assign c:\Windows\notepad.exe, you would have to write:

```
outln("\"Hi,\ttabbed world!\"")
program = "c:\\Windows\\notepad.exe"
```

Note that for file names on a Windows computer, it is important to convert back slashes ('\') to forward slashes (/). Otherwise, the file name may be translated incorrectly and the file won't be found.

24.4 Flow Control

Comparison Operators

SamUL supports many ways of comparing data. These types of tests can control the program flow with branching and looping constructs that we will discuss later.

There are six standard comparison operators that can be used on most types of data. For text strings, "less than" and "greater than" are with respect to alphabetical order.

Comparison	Operator
Equal	==
Not Equal	!=
Less Than	<
Less Than or Equal	<=
Greater Than	>
Greater Than or Equal	>=

Examples of comparisons:

```
divisor != 0
state == "oregon"
error <= -0.003
"pv" > "csp"
```

Single comparisons can be combined by boolean operators into more complicated tests.

The not operator yields true when the test is false. It is placed before the test whose result is to be notted:

```
not (divisor == 0)
```

The and operator yields true only if both tests are true:

```
divisor != 0 and dividend > 1
```

The or operator yields true if either test is true:

```
state == öregon" or state == "colorado"
```

The boolean operators can be combined to make even more complex tests. The operators are listed above in order of highest precedence to lowest. If you are unsure of which test will be evaluated first, use parentheses to group tests. Note that the following statements have very different meanings.

```
state_count > 0 and state_abbrev == "CA" or state_abbrev == "OR"
state_count > 0 and (state_abbrev == "CA" or state_abbrev == "OR")
```

Branching

Using the comparison and boolean operators to define tests, you can control whether a section of code in your script will be executed or not. Therefore, the script can make decisions depending on different circumstances and user inputs.

if Statements

The simplest branching construct is the if statement. For example:

```
if ( tilt < 0.0 )
  outln("Error: tilt angle must be 0 or greater")
end
```

Note the following characteristics of the if statement:

- The test is placed in parentheses after the if keyword.
- The following program lines include the statements to execute when the if test succeeds.
- To help program readability, the statements inside the if are usually indented.
- The construct concludes with the end keyword.
- When the if test fails, the program statements inside the if-end block are skipped.

else Construct

When you also have commands you wish to execute when the if test fails, use the else clause. For example:

```
if ( power > 0 )
  energy = power * time
  operating_cost = energy * energy_cost
else
  outln("Error, no power was generated.")
  energy = -1
  operating_cost = -1
end
```

Multiple if Tests

Sometimes you wish to test many conditions in a sequence, and take appropriate action depending on which test is successful. In this situation, use the elseif clause. Be careful to spell it as a single word, as both else if and elseif can be syntactically correct, but have different meanings.

```
if ( angle >= 0 and angle < 90)
  text = "first quadrant"
elseif ( angle >= 90 and angle < 180 )
  text = "second quadrant"
elseif ( angle >= 180 and angle < 270 )
  text = "third quadrant"
else
  text = "fourth quadrant"
end
```

You do not need to end a sequence of elseif statements with the else clause, although in most cases it is appropriate so that every situation can be handled. You can also nest if constructs if needed. Again, we recommend indenting each level of nesting to improve your script's readability. For example:

```
if ( angle >= 0 and angle < 90 )
  if ( print_value == true )
    outln( "first quadrant: " + angle )
  else
    outln( "first quadrant" )
  end
end
```

Single line ifs
Sometimes you only want to take a single action when an if statement succeeds. To reduce the amount of code you must type, SamUL accepts single line if statements, as shown below.

```
if ( azimuth < 0 ) outln( "Warning: azimuth < 0, continuing..." )

if ( tilt > 90 ) tilt = 90  ' set maximum tilt value
```

You can also use an else statement on single line if. Like the if, it only accepts one program statement, and must be typed on the same program line. Example:

```
if ( value > average ) outln("Above average") else outln("Not above average")
```

Looping

A loop is a way of repeating the same commands over and over. You may need to process each line of a file in the same way, or sort a list of names. To achieve such tasks, SamUL provides two types of loop constructs, the while and for loops.

Like if statements, loops contain a "body" of program statements followed by the end keyword to denote where the loop construct ends.

while Loops
The while loop is the simplest loop. It repeats one or more program statements as long as a logical test holds true. When the test fails, the loop ends, and the program continues execution of the statements following the loop construct. For example:

```
while ( done == false )
  ' process some data
  ' check if we are finished and update the 'done' variable
end
```

The test in a while loop is checked before the body of the loop is entered for the first time. In the example above, we must set the variable done to false before the loop, because otherwise no data processing would occur. After each iteration ends, the test is checked again to determine whether to continue the loop or not.

Counter-driven Loops

Counter-driven loops are useful when you want to run a sequence of commands for a certain number of times. As an example, you may wish to display only the first 10 lines in a text file.

There are four basic parts of implementing a counter-driven loop:

- Initialize a counter variable before the loop begins.
- Test to see if the counter variable has reached a set maximum value.
- Execute the program statements in the loop, if the counter has not reached the maximum value.
- Increment the counter by some value.

For example, we can implement a counter-driven loop using the while construct:

```
i = 0   ' use i as counter variable
while (i < 10)
  outln( "value of i is " + i )
  i = i + 1
end
```

for Loops

The `for` loop provides a streamlined way to write a counter-driven loop. It combines the counter initialization, test, and increment statements into a single line. The script below produces exactly the same effect as the `while` loop example above.

```
for ( i = 0; i < 10; i = i+1 )
  outln( "value of i is " + i )
end
```

The three loop control statements are separated by semicolons in the for loop statement. The initialization statement (first) is run only once before the loop starts. The test statement (second) is run before entering an iteration of the loop body. Finally, the increment statement is run after each completed iteration, and before the test is rechecked. Note that you can use any assignment or calculation in the increment statement.

Just like the `if` statement, SamUL allows for loops that contain only one program statement in the body to be written on one line. For example:

```
for ( val=57; val > 1; val = val / 2 ) outln("Value is " + val )
```

Loop Control Statements

In some cases you may want to end a loop prematurely. Suppose under normal conditions, you would iterate 10 times, but because of some rare circumstance, you must break the loop's normal path of execution after the third iteration. To do this, use the `break` statement.

```
value = double( in("Enter a starting value") )
for ( i=0; i<10; i=i+1 )
```

```
        outln("Value is " + value )
        if (value < 0)
            break
        end
        value = value / 3.0
    end
```

In another situation, you may not want to altogether break the loop, but skip the rest of program statements left in the current iteration. For example, you may be processing a list of files, but each one is only processed if it starts with a specific line. The `continue` keyword provides this functionality.

```
    for ( i=0; i<file_count; i=i+1 )
        file_header_ok = false

        ' check if whether current file has the correct header

        if (file_header_ok == false)
            continue
        end

        ' process this file
    end
```

The `break` and `continue` statements can be used with both `for` and `while` loops. If you have nested loops, the statements will act in relation to the nearest loop structure. In other words, a `break` statement in the body of the inner-most loop will only break the execution of the inner-most loop.

Quitting

SamUL script execution normally ends when there are no more statements to run at the end of the script. However, sometimes you may need to halt early, if the user chooses not to continue an operation.

The `exit` statement will end the SamUL script immediately. For example:

```
    if ( yesno("Do you want to quit?") == true )
        outln("Aborted.")
        exit
    end
```

The `yesno` function call displays a message box on the user's screen with **Yes** and **No** buttons, showing the given message. It returns `true` if the user clicked yes, or `false` otherwise.

24.5 Arrays of Data

Often you need to store a list of related values. For example, you may need to refer to the price of energy in different years. Or you might have a table of state names and capital cities. In SamUL, you can use arrays to store these types of collections of data.

Initializing and Indexing

An array is simply a list of variables that are indexed by numbers. Each variable in the array is called an element of the array, and the position of the element within the array is called the element's index. The index of the first element in an array is always 0.

To access array elements, enclose the index number in square brackets immediately following the variable name. SamUL does not require you to declare or allocate space for the array data in advance.

```
names[0] = "Sean"
names[1] = "Walter"
names[2] = "Pam"
names[3] = "Claire"
names[4] = "Patrick"

outln( names[3] ) ' output is "Claire"
my_index = 2
outln( names[my_index] ) ' output is "Pam"
```

You can also initialize a fixed array using the `array` command provided in SamUL. Simply separate each element with a comma. There is no limit to the number of elements you can pass to array.

```
names = array("Sean", "Walter", "Pam", "Claire", "Patrick")
outln( "First: " + names[0] )
outln( "All: " + names )
```

Note that calling the `typeof` function on an array variable will return "ärray" as the type description, not the type of the elements. This is because SamUL is not strict about the types of variables stored in an array, and does not require all elements to be of the same type.

Array Length

Sometimes you do not know in advance how many elements are in an array. This can happen if you are reading a list of numbers from a text file, storing each as an element in an array. After the all the data has been read, you can use the length function to determine how many elements the array contains.

```
count = length( names )
```

Processing Arrays

Arrays and loops naturally go together, since frequently you may want to perform the same operation on each element of an array. For example, you may want to find the total sum of an array of numbers.

```
numbers = array( 1, -3, 2.4, 9, 7, 22, -2.1, 5.8 )

count = length( numbers )
sum = 0
for (i=0; i<count; i=i+1)
  sum = sum + numbers[i]
end
```

The important feature of this code is that it will work regardless of how many elements are in the array.

Multidimensional Arrays

As previously noted, SamUL is not strict with the types of elements stored in an array. Therefore, a single array element can even be another array. This allows you to define matrices with both row and column indexes, and also three (or greater) dimensional arrays.

To create a multi-dimensional array, simply separate the indices with commas between the square brackets. For example:

```
data[0,0] = 3
data[0,1] = -2
data[1,0] = 5
data[2,0] = 1

nrows = length(data) ' result is 4
ncols = length(data[0]) ' result is 2

row1 = data[0] ' extract the first row

x = row1[0] ' value is 3
y = row1[1] ' value is -2
```

Managing Array Storage

When you define an array, SamUL automatically allocates sufficient computer memory to store the elements. If you know in advance that your array will contain 100 elements, for example, it can be much faster to allocate the computer memory before filling the array with data. Use the `allocate` command to make space for 1 or 2 dimensional arrays.

```
data = allocate(3,2) ' a matrix with 3 rows and 2 columns
data[2,1] = 3
prices = allocate( 5 ) ' a simple 5 element array
```

As before, you can extend the array simply by using higher indexes. However, if you know in advance how many more elements you will be adding, it can be faster to use the resize command to reallocate computer memory to store the array. resize preserves any data in the array, or truncates data if the new size is smaller than the old size.

```
data = allocate(5)
outln( length(data) )
resize(data, 10)
outln( length(data) )

resize(data, 2, 4)
outln( length(data) )
outln( length( data[0] ) )
```

Multiple Advance Declarations

You can also declare many variables and arrays in advance using the `declare` statement. For example:

```
declare radiation[8760], temp[8760], matrix[3,3], i=0
```

This statement will create the array variables radiation and temp, each with 8760 values. It will also set aside memory for the 3x3 matrix variable, and 'create' the variable i and assign it the value of zero. The declare statement can be a useful shortcut to creating arrays and initializing many variables in a single line. The only limitation is that you cannot define arrays of greater than two dimensions using the declare command.

24.6 Function Calls

It is usually good programming practice to split a larger program up into smaller sections, often called procedures, functions, or subroutines. A program may be easier to read and debug if it is not all thrown together, and you may have common blocks of code that appear several times in the program.

User Functions

A function is simply a named chunk of code that may be called from other parts of the script. It usually performs a well-defined operation on a set of variables, and it may return a computed value to the caller.

Functions can be written anywhere in your SAM script, including after they are called. If a function is never called by the program, it has no effect.

Definition

Consider the very simple procedure listed below.

```
function show_welcome()
  outln("Thank you for choosing SamUL.")
  outln("This text will only be displayed at the start of the script.")
end
```

Notable features:

- Use the function keyword to define a new function.
- The function name is next, and follows the same rules as for variable names. Valid function names can have letters, digits, and underscores, but cannot start with a digit.
- The empty parentheses after the name indicate that this function takes no parameters.
- The end keyword closes the function definition.
- To call the function from elsewhere in the code, simply write the function's name, followed by the parentheses:

  ```
  ' show a message to the user
  show_welcome()
  ```

Returning a Value

A function is generally more useful if it can return information back to the program that called it. In this example, the function will not return unless the user enters ÿes" or "no" into the input dialog.

```
function require_yes_or_no()
  while( true )
   answer = in("Destroy everything? Enter yes or no:")
   if (answer == "yes") return true
   if (answer == "no") return false
   outln("That was not an acceptable response.")
  end
end

' call the input function
result = require_yes_or_no() ' returns true or false
if ( not result )
  outln("user said no, phew!")
  exit
else
  outln("destroying everything...")
end
```

The important lesson here is that the main script does not worry about the details of how the user is questioned, and only knows that it will receive a true or false response. Also, the function can be reused in different parts of the program, and each time the user will be treated in a familiar way.

Parameters

In most cases, a function will accept arguments when it is called. That way, the function can change its behavior, or take different inputs in calculating a result. Analogous to mathematical functions, SamUL functions can take arguments to compute a result that can be returned. Arguments to a function are given names and are listed between the parentheses on the function definition line.

For example, consider a function to determine the minimum of two numbers:

```
function minimum(a, b)
  if (a < b) return a else return b
end

' call the function
count = 129
outln("Minimum: " + minimum( count, 77))
```

In SamUL, changing the value of a function's named arguments will modify the variable in the calling program. Instead of passing the actual value of a parameter a, SamUL always passes a reference to the variable in the original program. The reference is hidden from the user, so the variable acts just like any other variable inside the function.

Because arguments are passed by reference (as in Fortran, for example), a function can "return" more than one value. For example:

```
function sumdiffmult(s, d, a, b)
  s = a+b
  d = a-b
  return a*b
end

sum = -1
diff = -1
mult = sumdiffmult(sum, diff, 20, 7)

outln("Sum: " + sum + " Diff: " + diff + " Mult: " + mult) ' will output
27, 13, and 140
```

Variable Scope

Generally, variables used inside a function are considered "local", and cannot be accessed from the caller program. For example:

```
function triple(x)
  y = 3*x
end

triple( 4 )
outln( y ) ' this will fail because y is local to the triple function
```

As we have seen, we can write useful functions using arguments and return values to pass data into and out of functions. However, sometimes there are so many inputs to a function that it becomes very cumbersome to list them all as arguments. Alternatively, you might have some variables that are used throughout your program, or are considered reference values or constants. For these situations, you can define variables to be global in SamUL, and then they can be used inside functions and in the main program. For example:

```
global pi = 3.1415926

function circumference( r )
  return 2*pi*r
end

function deg2rad( x )
  return pi/180*x
end
```

```
outln( "PI: " + pi )
outln( "CIRC: " + circumference( 3 ) )
outln( "D2R: " + deg2rad( 180 ) )
```

Common programming advice is to minimize the number of global variables used in a program. Sometimes the are certainly necessary, but too many can lead to mistakes that are harder to debug and correct, and can reduce the readability and maintainability of your script.

Built-in SamUL Functions

Throughout this guide, we have made use of built-in functions like in, outln, and others. These functions are included with SamUL automatically, and called in exactly the same way as user functions. Like user functions, they can return values, and sometimes they modify the arguments sent to them. Refer to the Library Reference for documentation on each function's capabilities, parameters, and return values.

24.7 Input, Output, and System Access

SamUL provides a variety of standard library functions to work with files, directories, and interact with other programs. So far, we have used the in, out, and outln functions to accept user input and display program output in the runtime console window. Now we will learn about accessing files and other programs.

Working with Text Files

To write data to a text file, use the writetextfile function. writetextfile accepts any type of variable, but most frequently you will write text stored in a string variable. For example:

```
data = ""
for (i=0;i<10;i=i+1) data = data + "Text Data Line " + string(i) + "\n"
ok = writetextfile( "C:/test.txt", data )
if (not ok) outln("Error writing text file.")
```

Reading a text file is just as simple with the readtextfile function.

```
mytext = ""
if (not readtextfile( "C:/test.txt", mytext ))
  outln("could not read text file.")
else
  outln("text data:")
  out(mytext)
end
```

While these functions offer an easy way to read an entire text file, often it is useful to be able to access it line by line. SamUL provides the open, close, and readln functions for this purpose.

```
file = open("c:/test.txt", "r")
if (not file)
```

```
    outln("could not open file")
    exit
  end

  declare line
  while ( readln( file, line ) )
    outln( "My Text Line='" + line + "'" )
  end

  close(file)
```

In the example above, `file` is a number that represents the file on the disk. The `open` function opens the specified file for reading when the "r" parameter is given. The `readln` function will return true as long as there are more lines to be read from the file, and the text of each line is placed in the line variable.

Another way to access individual lines of a text file uses the split function to return an array of text lines. For example:

```
mytext = ""
readtextfile( "C:/test.txt", mytext )
lines = split( mytext, "\n" )
outln("There are " + length(lines) + " lines of text in the file.")
if (length(lines) > 5) outln("Line 5: '", lines[5], "'")
```

File System Functions

Suppose you want to run SAM with many different weather files, and consequently need a list of all the files in a folder that have the .tm2 extension. SamUL provides the directorylist function to help out in this situation. If you want to filter for multiple file extensions, separate them with commas.

```
file_names = directorylist( "C:/Windows", "dll" ) ' could also use "txt,dll"
outln("Found " + length(file_names) + " files that match.")
outln(unsplit(file_names, "\n"))
```

To list all the files in the given folder, leave the extension string empty or pass in "*".

Sometimes you need to be able to quickly extract the file name from the full path, or vice versa. The functions filenameonly and dirnameonly extract the respective sections of the file name, returning the result.

To test whether a file or directory exist, use the `direxists` or `fileexists` functions. Examples:

```
path = "C:/SAM/2010.11.9/samsim.dll"
dir = dirnameonly( path )
name = filenameonly( path )
outln( "Path: " + path )
outln( "Name: " + name + " Exists? " + fileexists(path) )
outln( "Dir: " + dir + " Exists? " + direxists(dir))
```

Standard Dialogs

To facilitate writing more interactive scripts, SamUL includes various dialog functions. We have already used the notice and yesno functions in previous examples.

The choosefile function pops up a file selection dialog to the user, prompting them to select a file. choosefile will accept three optional parameters: the path of the initial directory to show in the dialog, a wildcard filter like "*.txt" to limit the types of files shown in the list, and a dialog caption to display on the window. Example:

```
file = choosefile("c:/SAM", "*.dll", "Choose a DLL file")
if (file == "")
  notice("You did not choose a file, quitting.")
  exit
else
  if ( not yesno("Do you want to load:\n\n" + file)) exit

  ' proceed to load .dll file
  outln("Loading " + file)
end
```

Calling Other Programs

Suppose you have a program on your computer that reads an input file, makes some complicated calculations, and writes an output file. For example, a program could read in some system specifications and calculate its heat loss coefficients that could be used in a SAM analysis.

There are two very similar ways to call external programs: the system and shell functions. They are identical except that shell pops up an interactive system command window and runs the program in it. Both functions will wait until the called program finishes before returning to SamUL, so that the program runs synchronously. Examples:

```
system("notepad.exe") ' run notepad and wait
shell("ipconfig /all > c:/test.txt") ' run in the system shell
output = ""
readtextfile("c:/test.txt", output)
outln(output)
```

Each program runs in a folder that the program refers to as the working directory. Sometimes you may need to switch the working directory to conveniently access other files, or to allow an external program to run correctly.

```
working_dir = cwd()  ' get the current working directory
chdir( "C:/windows" ) ' change the working directory
outln("cwd=" + cwd() )
chdir(working_dir)  ' change it back to the original one
outln("cwd=" + cwd() )
```

24.8 Interfacing with SAM Analyses

The SamUL language would be of little interest if it did not allow for direct manipulation and automation of SAM analyses. To this end, there is a set of included function calls that can set SAM input variables, invoke a simulation, and retrieve output data.

All of the SamUL function calls involve only "base case" analysis. That is, the built-in parametrics, sensitivity, optimization, and statistical simulation types that are controlled from the user interface are not accessible from SamUL. This is probably less of a hindrance than it sounds, as SamUL exists primarily to allow for specialized simulations that do not fall into one of those categories.

Getting Started

SamUL scripts are part of a SAM project file that can consist of multiple cases and scripts. The general methodology is to have a SAM case that more or less describes the system you want to investigate, and then create a SamUL script within the same project that can manipulate the case. A SamUL script can only operate on one case at a time, and the active case is specified using the SetActiveCase function call. For example:

```
SetActiveCase("PV System in Arizona Case")
```

Changing Input Values

Once an active case has been chosen, you can change base case input values using the `SetInput` function. If an input affects other calculated variables, they are automatically recalculated, and the updated values are shown on the case input page. Calling `SetInput` causes the SAM interface to be updated just as if the user had changed the variable manually. Examples:

```
SetInput( "system degradation", 12.5 )   ' set degradation to 12.5 \%/year
SetInput( "pvwatts.array_type", 1 ) ' sets PVWatts array tracking mode to
one axis
```

SamUL requires that you provide the internal names of variables to access them. These names can be accessed from the third button on the SamUL toolbar. A dialog box will pop up, listing all SAM variables sorted by grouping and labels. The internal data type of a variable is also listed. Simply select the input variable from the hierarchical menu, and the internal name will be pasted into the SamUL script at the cursor position.

Unfortunately, because of the huge number of variables in SAM, there is no comprehensive reference manual that describes each variable's values or any special formatting that may be required. For example, the PV shading derate factor matrix is actually stored in memory as a one-dimensional column-major array, with the first two elements indicating the number of rows and columns respectively. Supposing that you had read in a 2D array from a text file into the `shading[i,j]` variable, you must convert it to a single dimensional array representation as below:

```
shadarr = allocate(12*24+2)
shadarr[0] = 12
shadarr[1] = 24
c=2
for (i=0; i<12; i=i+1)
```

```
    for (j=0; j<24; j=j+1)
     shadarr[c] = shading[i,j]
     c=c+1
    end
end
```

Then you can write `setinput("pv.shading.mxh.factors", shadarr)` and it will assign the factors correctly. The same holds true for most 2D matrix representations in SAM.

One exception is the heliostat field layout matrix for CSP Power Towers. The matrix is also stored as a one-dimensional array as described above, but there is one more number attached to the end of the array to hold the span angle in degrees. Thus the total array length is `nrows*ncols+3`. In any situation, it is always possible to call the GetInput with a variable to inspect how the data is stored.

```
setactivecase("New CSP Power Tower Case 1")

x = getinput("csp.pt.sf.user_field")
outln( "len=",length(x),": ",x)
```

Simulating and Saving Output

To start a base case simulation, use the simulate function. It take a boolean parameter to specify whether to save the hourly (8760) outputs from the simulation. After the simulation has finished, you can access the outputs using the getoutput function.

```
setactivecase( "Residential PV System" )
setinput( "system.degradation", 12.5 )  ' set degradation to 12.5 percent
simulate( )
lcoe = getoutput("sv.lcoe_real")
notice( "LCOE = " + lcoe )
```

As with the input variables, the internal variable names of the available outputs are also accessible from the SamUL toolbar.

You can also save several outputs to a comma-separated value (CSV) file to work with in Excel or another program using the `writeresults` function. The outputs variables are passed to the function separated by commas in a single string, and each variable is dumped as a separate column in the CSV file.

```
setactivecase( "Residential PV System" )
setinput( "system.degradation", 12.5 )  ' set degradation to 12.5 percent
simulate( )
writeresults( "c:/test.csv",
"system.hourly.e_net,system.monthly.e_net,sv.lcoe_nom")
```

Batching Weather Files

Let's return to the original hypothetical example discussed in the introduction. You have directory of weather files, and for each one you are asked to calculate the hourly generation and LCOE for the system.

The code addresses this need, and makes use of many SamUL language capabilities and built-in function calls.

```
' Set the active case from the current ones
setactivecase("Simple PV System")

' Specify a directory to use for weather batching
dir = "c:/Documents and Settings/David Smith/Desktop/Weather Files"

' List all the files in a directory that have the extension "tm2"
file_list = DirectoryList(dir, "tm2")

' loop through all the files
count = length(file_list)
for (i=0;i<count;i=i+1)

  out("Weather (",(i+1)," of ",count,")="+FileNameOnly(file_list[i])+"\n")
  ' set the climate variable to the file name
  setinput("climate.location", file_list[i])

  ' run the base case
  simulate( )

  ' make the output file name
  output_file = dir + "/output_" + FileNameOnly(file_list[i]) + ".csv"

  out("Writing Output File: "+FileNameOnly(output_file)+"\n\n")

  ' dump the needed results into a CSV file
  WriteResults(output_file, "system.hourly.e_net,sv.lcoe_nom")
end
```

This example and several others are included in the standard SAM sample files.

24.9 Code Sample: Latin Hypercube Sampling

SamUL's Latin Hypercube Sampling (LHS) functions are useful for statistical and uncertainty analyses. The LHS functions are available in the SAM Functions list. The following examples show some applications of the LHS functions.

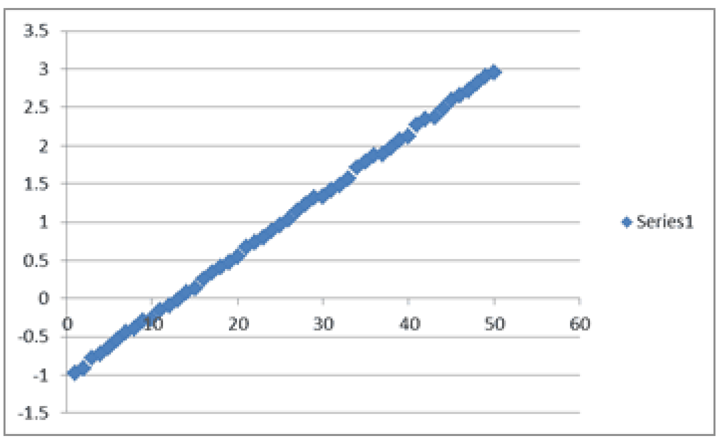
Using LHS to generate random numbers

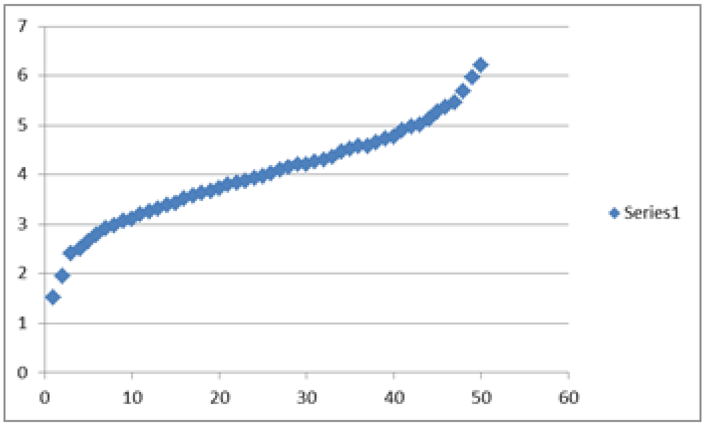
The following example illustrates how to use LHS functions to generate uniform and normal random numbers.

```
function getrand( distname, np, arg0, arg1 )
 lhs = lhscreate()
 lhsdist( lhs, distname, "a", arg0, arg1 )
 lhspoints( lhs, np )
 lhsseed( lhs, 123 )
 if (not lhsrun( lhs ))
  outln( lhserror( lhs ))
  lhsfree( lhs )
  return false
 else
  x = lhsvector( lhs, "a" )
  lhsfree( lhs )
  return x
 end
end

uu = getrand( "uniform", 50, -1, 3 )
nn = getrand( "normal", 50, 4, 1 )
```

```
for (i=0;i<50;i=i+1) outln( uu[i] + "\t" + nn[i] )
```

Plots of uu and nn (sorted):



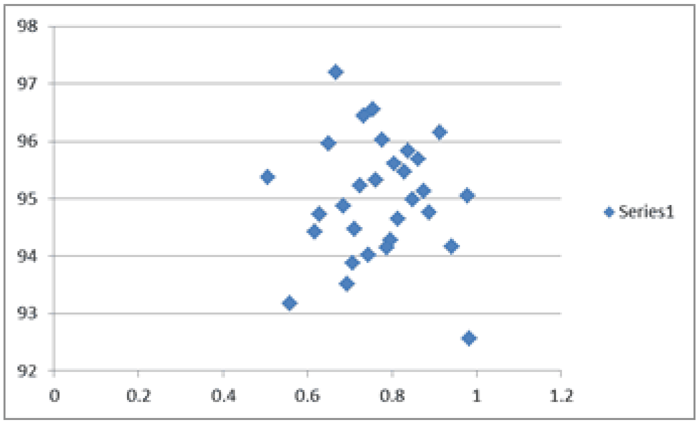


Using LHSCorr to establish a correlation between two LHS samples

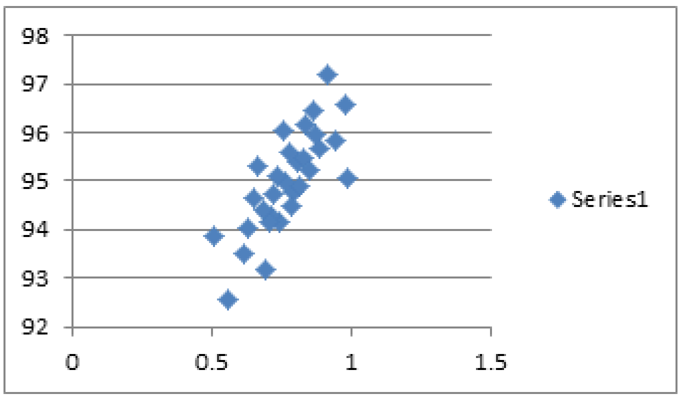
The following code creates two LHS samples, a and b. The lhscorr function (commented out in this example) establishes a correlation between the two samples. The graphs below the code show results with and without the lshcorr function.

```
lhs = lhscreate()

lhsdist( lhs, "normal", "a", 0.77, 0.1155 )
lhsdist( lhs, "normal", "b", 95, 1 )
'lhscorr( lhs, "a", "b", 0.8 )
np = 30
lhspoints( lhs, np )
lhsseed( lhs, 123 )

if (not lhsrun( lhs ))
 outln( lhserror( lhs ))
else
 a = lhsvector(lhs, "a")
 b = lhsvector(lhs, "b")
 outln("a\tb")
 for (i=0;i<np;i=i+1) outln( a[i] + "\t" + b[i] )
end


lhsfree( lhs )
```

Result when the line with the lhscorr function is commented out (no correlation):



Result when the line with the l hscor r command is enabled and 0.8 correlation is set between the variables a and b:



24.1 Library Reference 0

Type/Data Manipulation

TypeOf

( ):STRING

Returns a description of the argument type.

Integer

(VARIANT):INTEGER

Converts the variable to an integer number.

Double

(VARIANT):DOUBLE

Converts the variable to a double-precision floating point number.

Boolean

(VARIANT):BOOLEAN

Converts the variable to a boolean.

String

(...):STRING

Converts the given variables to a string.

IntegerArray

(STRING):ARRAY

Converts a string delimited by {;, tn} to an integer array.

DoubleArray

(STRING):ARRAY

Converts a string delimited by {;, tn} to a double-precision floating point array.

Length

(ARRAY):INTEGER

Return the length of an array.

Array

(...):ARRAY

Creates an array out of the argument list.

Allocate

(INTEGER:PRIMARY, [INTEGER:SECONDARY]):ARRAY

Creates an empty array with the specified dimensions.

Resize

(, INTEGER:PRIMARY, [INTEGER:SECONDARY]):NONE

Resizes an array or 2D matrix.

Append

(, ...):NONE

Appends one or more items to an array.

Prepend

(, ...):NONE

Prepends one or more items to an array.

Input/Output

Out

(...):NONE

Print data to the output device.

OutLn

(...):NONE

Print data to the output device followed by a newline.

Print

(STRING:Format, ...):NONE

Print formatted data to the output device using an extended 'printf' syntax.

In

(...):STRING

Request input from the input device, showing an optional prompt.

Notice

(...):NONE

Show a message dialog.

YesNo

(...):BOOLEAN)

Show a Yes/No dialog. Returns true if yes was clicked

ChooseFile

([STRING:Initial dir], [STRING:Filter], [STRING:Caption]):STRING

Show a file selection dialog, with optional parameters.

StartTimer

(NONE):NONE

Starts a stop watch timer.

ElapsedTime

(NONE):INTEGER

Returns elapsed milliseconds since last call to 'StartTimer'

MilliSleep

(INTEGER:Milliseconds):NONE

Sleep for the specified amount of time.

DateTime

(NONE):STRING

Returns the current date and time.

Open

(STRING:File, STRING:Mode):INTEGER

Opens a file for reading 'r', writing 'w', or appending 'a'.

Close

(INTEGER:FileNum):NONE

Closes a file.

Seek

(INTEGER:FileNum, INTEGER:Offset, INTEGER:Origin):INTEGER

Sets the position in an open file.

Tell

(INTEGER:FileNum):INTEGER

Returns the current file position.

Eof

(INTEGER:FileNum):BOOLEAN

Determines whether a file is at the end.

Flush

(INTEGER:FileNum):INTEGER

Flushes the current file object to disk.

Write

(INTEGER:FileNum, ...):BOOLEAN

Writes data as text to a file.

WriteN

(INTEGER:FileNum, VARIANT data, INTEGER: NumChars):BOOLEAN

Writes character data to a file.

WriteLn

(INTEGER:FileNum, VARIANT data):BOOLEAN

Writes a line to a file as a string.

ReadN

(INTEGER:FileNum, :Data, INTEGER:NumChars):BOOLEAN

Reads characters from a file.

ReadLn

(INTEGER:FileNum, :Line):BOOLEAN

Reads a line from a file, returning false if no more lines exist.

ReadFmt

(INTEGER:filenum, STRING:format=[idgefxsb]*, STRING:delimiters, ... VALUE ARGUMENT LIST):BOOLEAN

Reads a data line from a file with the given sequence of types and delimiters. Number of value arguments must equal number of characters in format string

OpenWF

(STRING:file, [ARRAY:header info]):INTEGER

Opens a weather (TM2, TM3, EPW) file for reading.

ReadWF

(INTEGER:filenum, ARRAY:y - m - d - h - gh - dn - df - wind - tdry - twet - relhum - pres *or* [INTEGER:y, INTEGER:m, INTEGER:d, INTEGER:h, DOUBLE:gh, DOUBLE:dn, DOUBLE:df, DOUBLE:wind, DOUBLE:tdry, DOUBLE:twet, DOUBLE:relhum, DOUBLE:pres]):BOOLEAN

Reads a line of data from a weather file.

CustomizeTMY3

(STRING:Source tmy3 file, STRING:Target tmy3 file, [STRING:Column name=gh - dn - df - tdry - twet - wind - pressure - relhum, ARRAY:Values(8760)]*):BOOLEAN

Overwrites columns of 8760 data in a TMY3 file and writes a new file.

WFStatistics

(STRING:File, :DN, :GH, :AMBT, :WSPD):BOOLEAN

Extracts annual averages of DN, GH, AmbT, and WSpd

WriteTextFile

(STRING:Filename, VARIANT data):BOOLEAN

Writes a file of text data to disk. Returns true on success.

ReadTextFile

(STRING:Filename, :Data):BOOLEAN

Reads a text file from disk, returning true on success.

GetHomeDir

(NONE):STRING

Returns the current user's home directory.

Cwd

(NONE):STRING

Returns the current working directory.

ChDir

(STRING: Path):BOOLEAN

Change the current working directory.

DirectoryList

(STRING:Path, STRING:Comma-separated extensions, [BOOLEAN:Include folders]):ARRAY

Enumerates all the files in a directory that match a comma separated string of extensions.

System

(STRING):INTEGER

Run a system command, returning the process exit code.

Shell

(STRING):BOOLEAN

Run a system command in a new console window. Returns true on success.

FileNameOnly

(STRING:Path):STRING

Returns only the file name portion of a full path.

DirNameOnly

(STRING:Path):STRING

Returns only the directory portion of a full path.

Extension

(STRING:File):STRING

Returns the extension of a file.

DirExists

(STRING:Path):BOOLEAN

Returns true if the specified directory exists.

FileExists

(STRING:Path):BOOLEAN

Returns true if the specified file exists.

CopyFile

(STRING:File1, STRING:File2):BOOLEAN

Copies file 1 to file 2.

RenameFile

(STRING:File1, STRING:File2):BOOLEAN

Renames file 1 to file 2.

DeleteFile

(STRING:File):BOOLEAN

Deletes the specified file.

MkDir

(STRING:Path):BOOLEAN

Creates a directory including the full path to it.

RmDir

(STRING:Path):BOOLEAN

Deletes a directory and everything it contains.

Decompress

(STRING:Archive, STRING:Target):BOOLEAN

Decompresses an archive file (ZIP, TAR, TAR.GZ, GZ).

HttpGet

(STRING:Url):STRING

Performs an HTTP web query and returns the result as plain text.

HttpDownload

(STRING:Url, STRING:LocalFile):BOOLEAN

Downloads a file form the web, showing a progress dialog.

String Manipulation

StrPos

(STRING, STRING:Search):INTEGER

Returns the first position of the search string, or -1 if not found.

StrRPos

(STRING, STRING:Search):INTEGER

Returns the first position of the search string from the right, or -1 if not found.

StrLeft

(STRING, INTEGER:N):STRING

Returns the left 'N' character string.

StrRight

(STRING, INTEGER:N):STRING

Returns the right 'N' character string.

StrLower

(STRING):STRING

Returns a lower case version of the string.

StrUpper

(STRING):STRING

Returns an upper case version of the string.

StrMid

(STRING, INTEGER:Start, [INTEGER:Count]):STRING

Returns the substring from the specified start position, of length 'count'. If 'count' is not supplied, the remainder of the string is returned.

StrLen

(STRING):INTEGER

Returns the length of a string.

StrReplace

(STRING, STRING:s0, STRING:s1):STRING

Returns a string with all instances of 's0' replaced with 's1'.

StrCmp

(STRING:s0, STRING:s1):INTEGER

Case-sensitive comparison. Returns 0 if equal, positive if s0 comes before s1, and negative if s1 comes before s0.

StrICmp

(STRING:s0, STRING:s1):INTEGER

Case-insensitive comparison. Returns 0 if equal, positive if s0 comes before s1, and negative if s1 comes before s0.

StrGCh

(STRING, INTEGER:position):STRING

Gets the character at the specified position.

StrSCh

(STRING, INTEGER:position, STRING:char):NONE

Sets the character at the specified position.

Split

(STRING, STRING:delimiters):ARRAY

Splits the string into an array.

Unsplit

(ARRAY, STRING:delimiters):STRING

Unsplits an array into a string.

Format

(STRING:Format, ...):STRING

Formats data into a string using an extended 'printf' syntax.

Math

Mod

(INTEGER, INTEGER):INTEGER

Returns the remainder after X is divided by Y

Abs

(NUMBER):NUMBER

Absolute value of the number.

Min

(NUMBER, NUMBER *or* ARRAY):NUMBER

Returns the smaller of two values, or the smallest in an array.

Max

(NUMBER, NUMBER *or* ARRAY):NUMBER

Returns the larger of two values, or the largest in an array

Ceil

(NUMBER):DOUBLE

Returns the number rounded up to the nearest integer.

Floor

(NUMBER):DOUBLE

Returns the number rounded down to the nearest integer.

Sqrt

(NUMBER):DOUBLE

Returns the square root of a number.

Pow

(NUMBER:X, NUMBER:Y):DOUBLE

Returns 'X' raised to the 'Y' power.

Exp

(NUMBER):DOUBLE

Returns the exponential value, base 'e'.

Log

(NUMBER):DOUBLE

Returns the logarithm of a number, base 'e'.

Log10

(NUMBER):DOUBLE

Returns the logarithm of a number, base 10.

Sin

(NUMBER):DOUBLE

Returns the sine of a radian value.

Cos

(NUMBER):DOUBLE

Returns the cosine of a radian value.

Tan

(NUMBER):DOUBLE

Returns the tangent of a radian value.

ASin

(NUMBER):DOUBLE

Returns the arcsine of a number in radians.

ACos

(NUMBER):DOUBLE

Returns the arccosine of a number in radians.

ATan

(NUMBER):DOUBLE

Returns the arctangent of a number in radians.

ATan2

(NUMBER:Y, NUMBER:X):DOUBLE

Returns the arctangent of 'Y'/'X' in radians.

IsNan

(DOUBLE):BOOLEAN

Returns true if the number is NAN.

NanVal

(NONE):DOUBLE

Returns NAN.

SAM Functions

SetInput

(STRING:Variable name, VARIANT value):NONE

Sets an input in the active case.

GetInput

(STRING:Variable name):VARIANT

Returns an input value from the active case.

GetOutput

(STRING:Variable name):ARRAY

Returns a base case output from the active case's results as a double-precision array.

ResetOutputSource

(NONE or STRING:Simulation name, INTEGER:Run number):NONE

Resets the output data source to default BASE case, or changes it to a different simulation and run number.

ClearSimResults

(STRING:Simulation name):NONE

Clears all results for the specific simulation name.

SetActiveCase

(STRING:Case name):NONE

Sets the active case.

GetActiveCase

(NONE):STRING

Returns the active case name.

SwitchToCase

(NONE):NONE

Switches to the active case tab in the interface.

ChangeConfig

(STRING:Technology, STRING:Financing):BOOLEAN

Changes the current case's configuration. Application must be '*'.

ListCases

(NONE):ARRAY

Lists all the cases in the project.

ProjectFile

(NONE):STRING

Returns the current project file name.

AppYield

(NONE):NONE

Yields the interface to respond to user input.

SaveProject

(NONE): BOOLEAN

Saves the project.

SaveProjectAs

(STRING):BOOLEAN

Saves the project to the specified file.

Simulate

(BOOLEAN:Save hourly data):NONE

Runs a base case simulation with the current inputs, with the option of saving hourly results.

MPSimulate

(STRING:Simulation name, ARRAY[ARRAY]:Variable name/value table NRUNS+1 x NVARS with top row having var names):BOOLEAN

Runs many simulations using multiple processors.

WriteResults

(STRING:File name, STRING:Comma-separated output variable names):BOOLEAN

Write a comma-separated-value file, with each column specified by a string of comma-separated output names.

ClearResults

(NONE):NONE

Clear the active case's results from memory.

ClearCache

(NONE):NONE

Clear the memory cache of previously run simulations.

DeleteTempFiles

(NONE):NONE

Delete any lingering simulation temporary files.

SetTimestep

(STRING:Timestep with units):NONE

Sets the TRNSYS timestep for the active case.

ReloadDefaults

(NONE):NONE

Reloads all default values for the active case.

ListTechnologies

(NONE):ARRAY

Returns an array of all the technologies in SAM.

ListFinancing

(STRING:Technology):ARRAY

Lists all financing options in SAM for a given technology.

TechnologyType

(NONE):STRING

Returns the active case technology type.

FinancingType

(NONE):STRING

Returns the active case financing type.

ActiveVariables

([STRING:Technology, STRING:Financing]):ARRAY

List all active variables for the current case or technology/market name.

FluidDensity

(INTEGER:Fluid number, DOUBLE:Temp 'C):DOUBLE

Returns density at temperature Tc for a given fluid number (pressure assumed 1Pa).

FluidSpecificHeat

(INTEGER:Fluid number, DOUBLE:Temp 'C):DOUBLE

Returns specific heat at temperature Tc for a given fluid number (pressure assumed 1Pa).

FluidName

(INTEGER:Fluid number):STRING

Returns fluid name for a given fluid number.

PtOptimize

(NONE):NONE

Optimizes the power tower heliostat field, tower height, receiver height, and receiver diameter.

Coeffgen6par

(STRING:cell type, DOUBLE:Vmp, DOUBLE:Imp, DOUBLE:Voc, DOUBLE:Isc, DOUBLE:beta, DOUBLE,alpha, DOUBLE,gamma, INTEGER:nser):ARRAY[a,Io,Il,Rs,Rsh,Adj] or false on failure

Calculates the 6 parameters for the CEC 6 parameter model

LHSCreate

(NONE):INTEGER

Creates a new Latin Hypercube Sampling object.

LHSFree

(INTEGER:lhsref):NONE

Frees an LHS object.

LHSReset

(INTEGER:lhsref):NONE

Erases all distributions and correlations in an LHS object.

LHSSeed

(INTEGER:seed):NONE

Sets the seed value for the LHS object.

LHSPoints

(INTEGER:lhsref, INTEGER:number of points):NONE

Sets the number of samples desired.

LHSDist

(INTEGER:lhsref, STRING:distribution name, STRING: variable name, [DOUBLE:param1, DOUBLE:param2, DOUBLE:param3, DOUBLE:param4]): NONE

Sets up a distribution for a variable.

LHSCorr

(INTEGER:lhsref, STRING:variable 1, STRING:variable 2, DOUBLE:corr val):NONE

Sets up correlation between two variables.

LHSRun

(INTEGER:lhsref):BOOLEAN

Runs the LHS sampling program.

LHSError

(INTEGER:lhsref):STRING

Returns an error message if any.

LHSVector

(INTEGER:lhsref, STRING:variable):ARRAY

Returns the sampled values for a variable.

STEPCreate

(NONE):INTEGER

Create a new STEPWISE regression analysis object.

STEPFree

(INTEGER:stpref):NONE

Frees a STEPWISE object.

STEPInput

(INTEGER:stpref, STRING:name, ARRAY:values):NONE

Sets a STEPWISE input vector.

STEPOutput

(INTEGER:stpref, ARRAY:values):NONE

Sets a STEPWISE output vector.

STEPRun

(INTEGER:stpref):NONE

Runs the STEPWISE analysis.

STEPError

(INTEGER:stpref):STRING

Returns any error code from STEPWISE.

STEPResult

(INTEGER:stpref, STRING:name):ARRAY

Returns R2 and SRC for a given input name.

OpenEIListUtilities

(NONE):ARRAY

Returns a list of utility company names from OpenEI.org

OpenEIListRates

(STRING:Utility name, ,):INTEGER

Lists all rate schedules for a utility company.

OpenEIApplyRate

(STRING:Guid):BOOLEAN

Downloads and applies the specified rate schedule from OpenEI.

URdbFileWrite

(STRING:file):BOOLEAN

Writes a local URdb format file with the current case's utility rate information.

URdbFileRead

(STRING:file):BOOLEAN

Reads a local URdb format file and overwrites the current case's utility rate information.

25 Analysis Options

Analysis Options allow you to set up analyses that involve multiple simulations:

- Parametric Analysis: Assign multiple values to input variables to create graphs and tables showing the value of output metrics for each value of the input variable.
- Sensitivity Analysis: Create tornado graphs by specifying a range of values for input variables as a percentage.
- Statistical: Create histograms showing the sensitivity of output metrics to variations in input values.
- Multiple Subsystems: For files with multiple cases, assumes that the system's total electrical output is the sum of the output of the systems modeled in each case, and applies the financing model from one case to this total output.
- Excel Exchange: Use Microsoft Excel to calculate the value of input variables, and automatically pass

values of input variables between SAM and Excel.

- P50/P90 Analysis: When weather data is available for many years, calculate the probability that the system's total annual output will exceed a certain value.
- Exchange Variables: Create your own input variables for use with Excel Exchange or a custom TRNSYS deck.

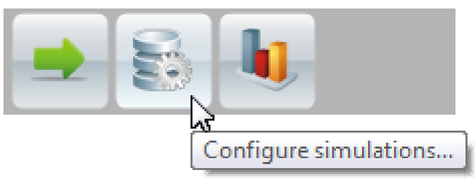
25.1 Parametric Analysis

A parametric analysis makes it possible to create graphs showing the relationship between a result metric and one or more input variables. You might use such a graph for showing relationships between variables, or for optimizing the value of an input variable. For example:

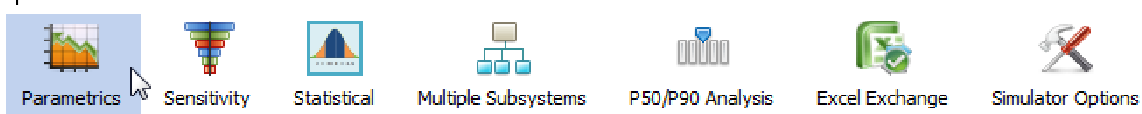
- For one of the utility financing options, show the relationship between internal rate of return and power purchase agreement price.
- For photovoltaic systems, create a graph of annual energy (or levelized cost of energy) versus array tilt and azimuth to optimize the array orientation.
- For CSP trough systems with thermal energy storage, create a graph showing levelized cost of energy versus solar multiple and thermal storage capacity. (See Sizing the Solar Field for the physical trough model, or Sizing the Solar Field for the empirical trough model.)

To display the parametric simulation setup options:

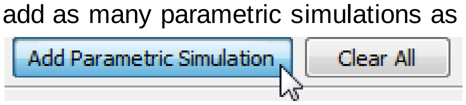
1. On the Main window, click **Configure Simulations** to view the Configure Simulation page.



2. On the Configure Simulations page, click **Parametrics** to display the Parametric simulation setup options.



3. Click **Add Parametric Simulation** to add a set of parametric simulation setup options. You can add as many parametric simulations as your analysis requires.

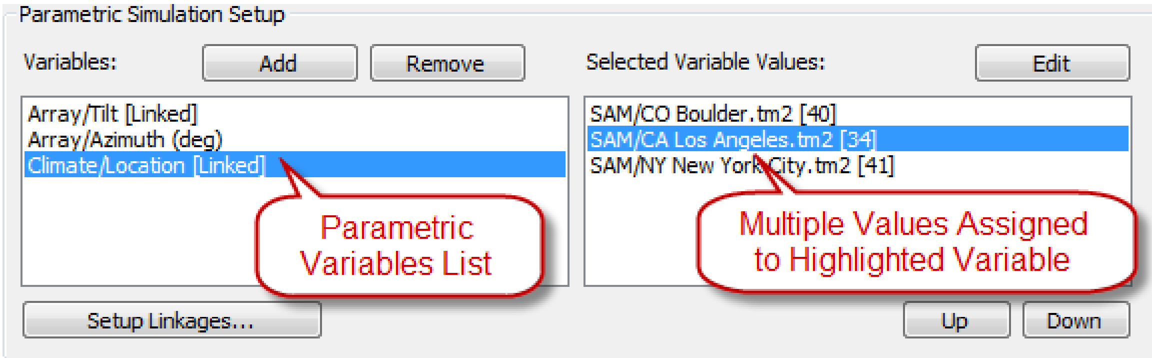


Click **Remove Simulation** to delete an analysis option.

Click **Clear All** to remove all analysis options from the case.

Parametric Simulation Setup

The Parametric Simulation Setup options allow you to add and remove variables from the list of parametric variables, assign values to and edit parametric variables, and to set up linkages between parametric variables that have interdependent values.



Add

Add an input variable to the parametric variables list. You must add a variable before you can assign it multiple values.

Remove

Remove a variable from the parametric variables list. When you remove a variable, SAM assigns the value from the variable's input page to the variable.

Setup Linkages

Create linkages between parametric variables when the values of one of the variables is dependent on those of the other.

Edit

Assign values to or edit values of the variable highlighted in the parametric variables list.

Up

Move the highlighted value in the variable values list up one row.

Down

Move the highlighted value in the variable values list down one row.

Remove Simulation

Remove the parametric simulation setup and delete all parametric values. You can also clear the Enable this simulation checkbox to keep the setup options but exclude the parametric analysis from simulations.

Enable this simulation

This box must be checked for the parametric simulation setup to be included in simulations when you run the model.

Setting up a Parametric Analysis

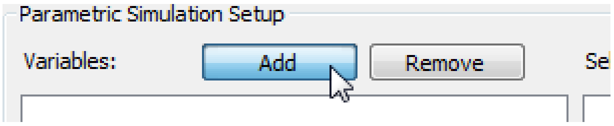
Once you have added a parametric simulation, you must add one or more parametric variables to the simulation, and assign multiple values to each variable.

After setting up the optimization, click the Run All Simulations button, or click **Run All Simulations** on the Case menu to run the optimization and any other enabled simulations.

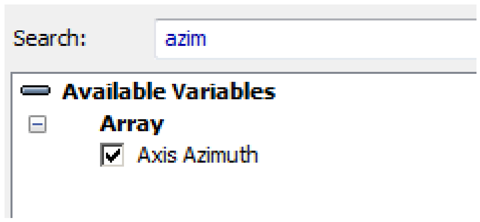
To set up a parametric analysis:

1. Display the parametric simulation setup options as described above.

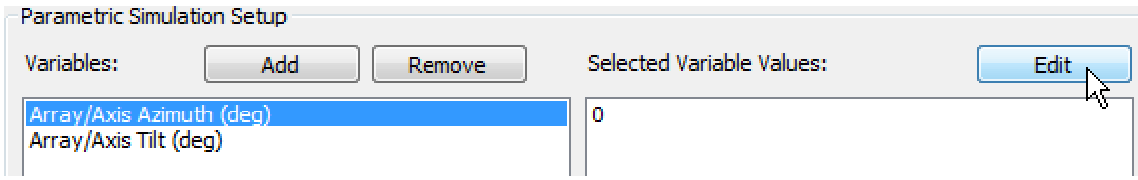
2. Click **Add** to choose variables to which you want to assign multiple values from a list of available input variables.



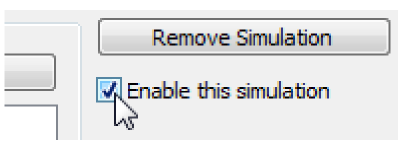
3. In the Search box, type the first few letters of the variable name and check the variable's box in the list of available variables.



4. Highlight each variable in the parametric variables list and click **Edit** to assign values to the variables. See Working with Numeric Ranges for details.



5. Check **Enable this simulation** to include the parametric analysis in simulation runs. You can save the parametric simulation setup options and exclude the analysis from simulations by clearing the checkbox. Clearing the checkbox allows you to shorten simulation run times without losing the setup configuration.



Working with Linkages

In some analyses, parametric variables may be interdependent. For example:

- Tilt depends on location when an analysis assumes that the photovoltaic array or CSP collector tilt angle is equal to the location's latitude.
- Thermal storage capacity depends on the solar multiple for a CSP trough analysis that assumes that the storage system capacity scales with the solar field area.

For these analyses, linking the interdependent parametric variables prevents SAM from simulating combinations of parametric variable values that are not relevant to the analysis. For example, linking the array or collector tilt variable to the location variable ensures that SAM only simulates systems that use a location's latitude as the tilt angle. Without linkages, SAM would simulate all combinations of locations and tilt values.

To setup a linkage between two parametric variables:

1. Add the two variables to the parametric variables list as described above. The parametric variables list may include other variables.

2. Click **Setup Linkages**.
3. In the Choose Linked Parametric Variables window, check the variable names for each of the two linked variables.
4. Click **OK**. SAM displays the word "Linked" in brackets next to the variable names in the parametric variables list indicating the linked variables
5. Click the first linked variable. SAM displays the variable's values in the variable values list, and shows the value of the other linked variable in brackets.
6. Click **Edit** to assign multiple values to the first linked variable. See Working with Numeric Ranges for details.
7. Click **OK**. SAM displays question marks in brackets next to the values of the second linked variable to which you have not yet assigned values.
8. In the parametric variables list, click the second linked variable.
9. Click **Edit** to assign multiple values to the variable. Note that you should assign the same number of values to this variable as you did to the first linked variable.
10. Click **OK**. SAM displays the values of both variables in the variable values list. Check the list to make sure that there are no question marks in brackets indicating a missing linked value and that the values are in correctly matched pairs.

Parametric Analysis Results in Graphs and Tables

After running simulations for a parametric analysis, you can create graphs and tables to show results.

To create graphs of parametric analysis results:

1. Set up the parametric variables and run simulations.
2. On the Results page, click **Graphs**.
3. Click **Add a new graph**.
4. Under **Choose Simulation**, choose **Parametric Set 1**.

   Choose **Base Case** to create graphs of input variable values that you see on the input pages. When you run simulations for parametric or other analyses that involve input variables with more than one value, SAM lists the analysis options in addition to the base case.
5. For **X Value**, choose the parametric variable that you want to appear on the X axis.

   When your analysis includes more than one parametric variable, you can create a contour graph with parametric variables for the X and Y axes.
6. Choose appropriate options for your graph. See Edit Graph Window for details.
7. Click **Accept**.

   SAM creates the graph, displays it on the Results page, and adds a thumbnail for the graph.

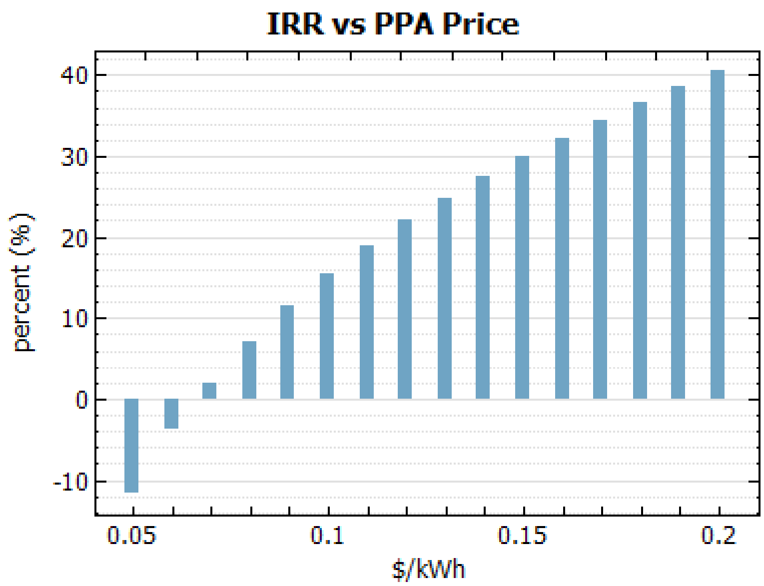
To create tables of parametric analysis results:

1. Set up the parametric variables and run simulations.
2. On the Results page, click **Tables**.
3. For **Choose Simulation**, choose **Parametric Set 1**.
4. Under **Output Variables**, choose the variables you want to display in the table.

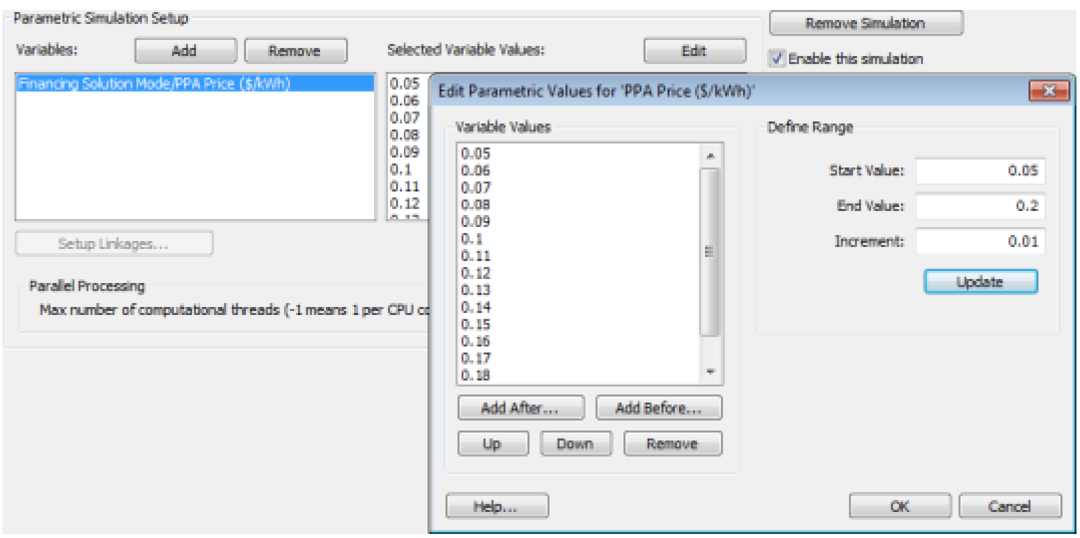
   SAM displays a column of values for each parametric variable's value.

Example 1. Graph the relationship between an input variables and a result

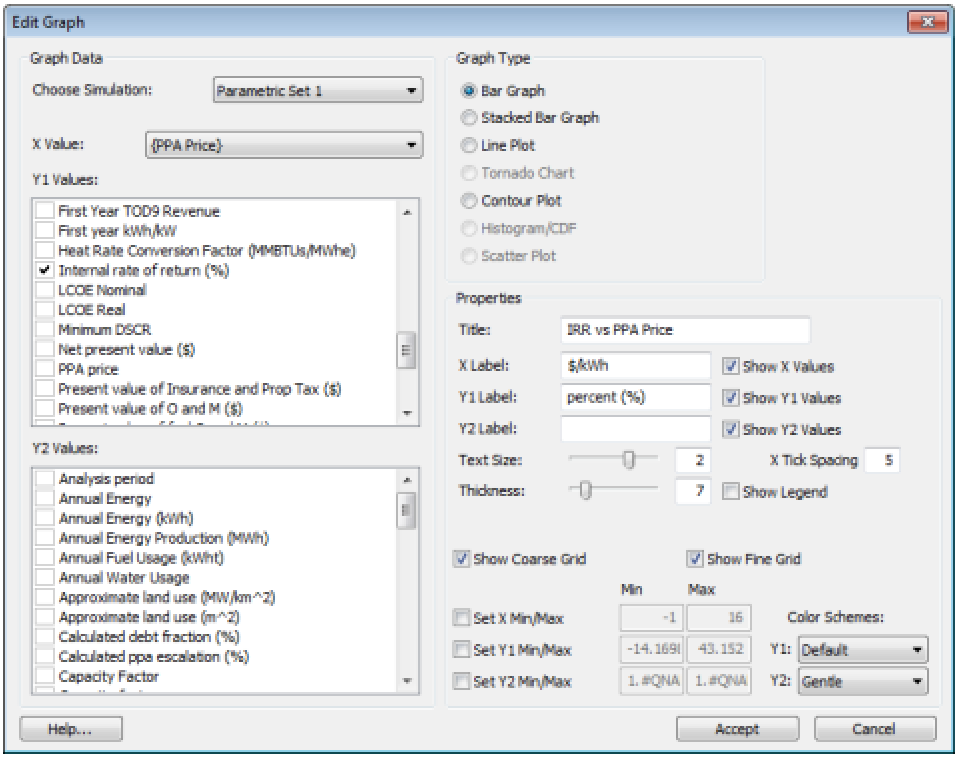
The following graph is for a 58 MW wind farm with an installed cost of $3,000 per kW, and shows the relationship between the project internal rate (result) of return and PPA price (input). The graph shows that the project requires a PPA price of at least 7 cents/kWh to make a positive return on investment:



To plot the graph, we chose the Specify PPA Price option on the Financing page, and on the Parametrics input page, added PPA Price as a parametric variable with Start Value = $0.05/kWh, End Value = $0.2/kWh, and Increment of $0.01/kWh.



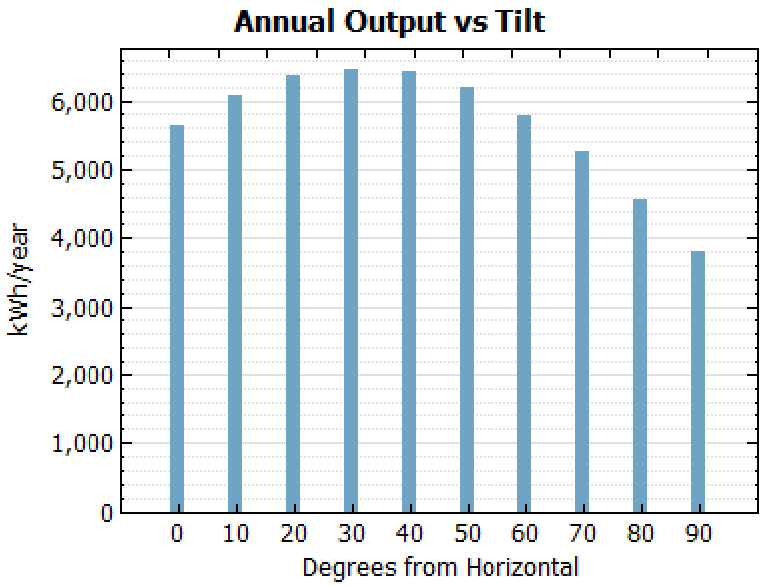
After running simulations, on the Results page, we added a new graph with the following properties Choose Simulation = Parametric Set 1, X Value = PPA Price, Y1 Values = Internal Rate of Return, Graph Type = Bar Graph:



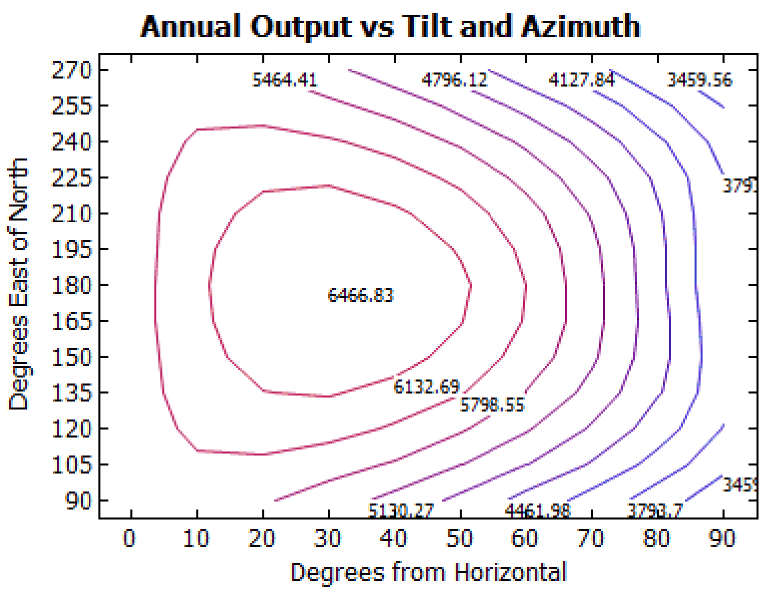
Example 2: Optimize Photovoltaic Array Tilt and Azimuth Angles

The following graphs show how to use parametric analyses to optimize the array orientation of a photovoltaic system. We created the graphs by setting up a system using the PVWatts performance model for a 4 kW system.

The first graph shows how for the 4 kW system in Phoenix, Arizona, the annual electric output depends on the array tilt. We defined tilt variable as a parametric variable with ten values: 0, 10, 20, 30, 40, 50, 60, 70, 80, and 90 degrees from horizontal. The bar graph shows Parametric Set 1 results with Tilt as the X Value and Annual Energy as the Y1 Value:

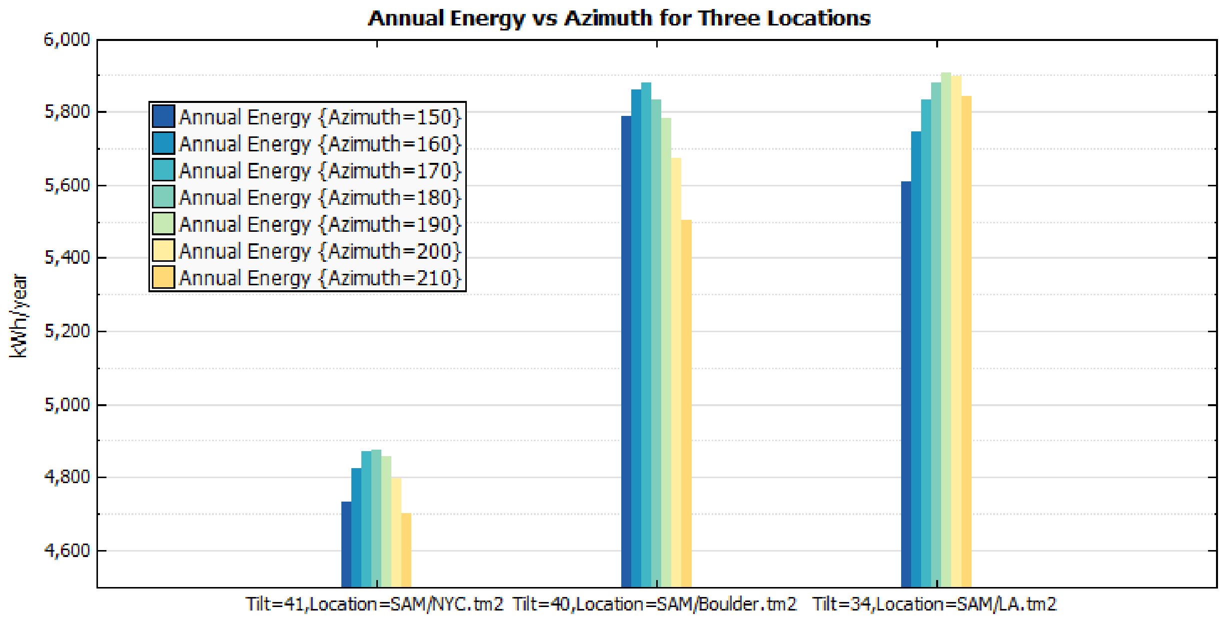


The next graph shows how the first year annual electric output depends on both the array tilt and azimuth. We used the same range of values for the tilt variable, and added azimuth as a parametric variable with values between 90 and 270 degrees east of north in increments of 15 degrees. The contour graph shows Parametric Set 1 results with Annual Energy as the Z Value, tilt as the X Parametric, and azimuth as the Y Parametric:



The third graph shows the relationship between the first year annual electric output and array azimuth for three locations, assuming an array tilt equal to the location's latitude. We assigned a range of azimuth angle values between 150 and 210 degrees east of north. We linked the tilt and location variables as follows: Location = Boulder / Tilt = 40 degrees, Location = Los Angeles / Tilt = 34 degrees, Location = New York City / Tilt = 41 degrees.

Each cluster of bars in the graph shows the annual energy output for each azimuth value for New York, Boulder, and Los Angeles. Because of different weather patterns in each city, the optimal azimuth angle is different for each city. For example, summer afternoon thunderstorms in Boulder cause the optimal azimuth angle to be 170 degrees east of north, or about 10 degrees east of south, which is oriented away from the foothills to the west where the summer afternoon clouds block the sun.



25.2 Sensitivity Analysis

The sensitivity analysis option allows you to specify a range of values as a percentage for one or more input variables to investigate how sensitive an output metric is to variations in the input variables' values. Examples of sensitivity analyses include:

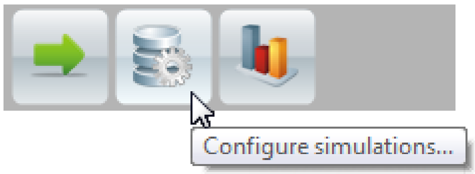
- Determining the sensitivity of the levelized cost of energy to different capital cost components.
- Comparing the sensitivity of the levelized cost of energy to capital cost and financial assumptions.

Configuring sensitivity analyses makes it possible to plot tornado graphs on the Results page showing the range of an output metric values for one or more sensitivity variables.

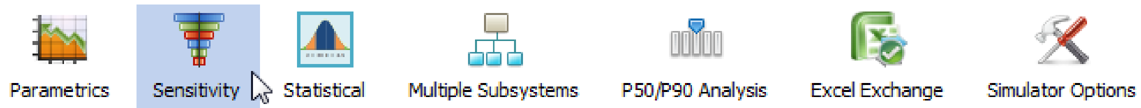
Note. SAM calculates results for each sensitivity variable independently. In some analyses, this may cause misleading results. This is especially true when the sensitivity variable is a performance input variable rather than a cost or financial input variable. For example, for CSP trough systems with storage, varying the thermal storage capacity independently of the tank heat loss variable to examine how sensitive the system's electrical output is to storage capacity would not accurately account for the expected increase in heat loss for larger storage systems. Similarly, for photovoltaic systems, varying the number of modules per string independently of the inverter type or number of inverters might result in inaccurate system output calculations if the inverter is improperly sized for a number of modules within the range specified for the sensitivity analysis.

To display the sensitivity simulation setup options:

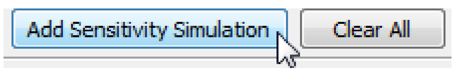
1. On the Main window, click **Configure Simulations** to view the Configure Simulation page.



2. On the Configure Simulations page, click **Sensitivity** to display the Parametric simulation setup options.



3. Click **Add Sensitivity Simulation** to add a set of sensitivity simulation setup options. You can add as many sensitivity simulations as your analysis requires.

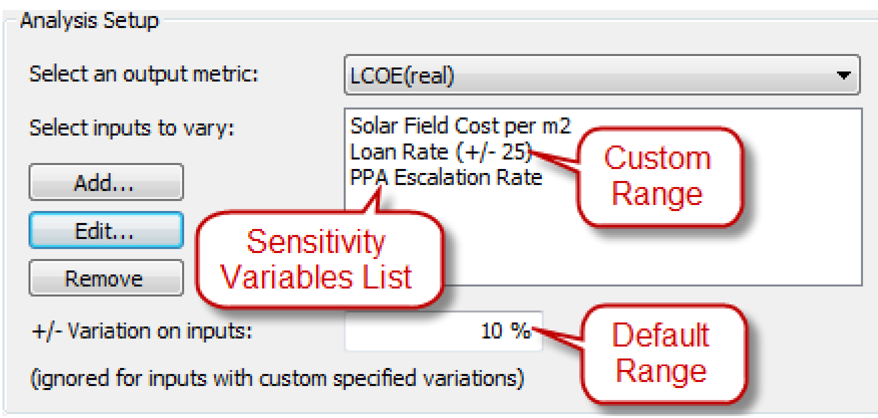


Click **Remove Simulation** to delete an analysis option.

Click **Clear All** to remove all analysis options from the case.

Analysis Setup

The Analysis Setup options allow you to choose an output metric, add and remove variables from the list of sensitivity variables, assign values to and edit sensitivity variables, and assign ranges to each sensitivity variable.



Select an output metric

Choose an output metric for the sensitivity analysis. This metric will appear on tornado graphs in the results.

Add

Add an input variable to the sensitivity variables list.

Edit

Assign a "custom" variation range to the variable highlighted in the sensitivity variables list. SAM assigns the default range to all sensitivity variables that do not have a different custom range. SAM indicates the custom range in parentheses next to the variable's name in the sensitivity variable list.

Remove

Remove a variable from the sensitivity variables list.

+/- Variation on inputs

The default range applied to all sensitivity variables that do not have a different custom range. For a range value of 10 %, SAM would calculate the range of values of an input variable between 10 % below and 10 % above the variable's value on the input page.

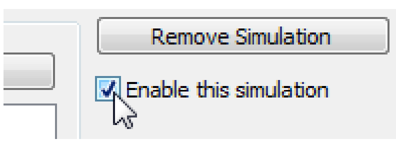
Setting up a Sensitivity Analysis

Once you have added a sensitivity simulation, you must add one or more sensitivity variables to the simulation.

After setting up the analysis, click the Run button, or click **Run All Simulations** on the Case menu to run the analysis and any other enabled simulations.

To set up a sensitivity analysis:

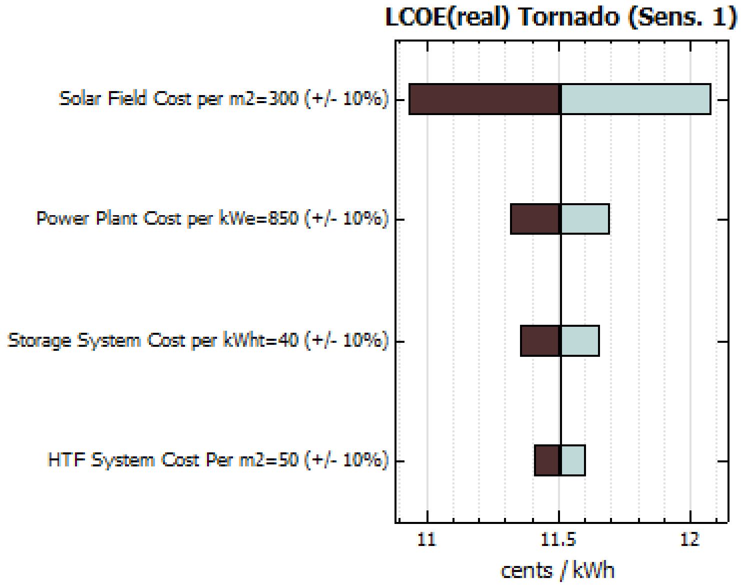
1. Display the sensitivity simulation setup options as described above.
2. Click **Add** to choose variables to which you want to assign a variation range from a list of available input variables. SAM adds the variables to the sensitivity variables list.
3. If you want to use a variation range value other than the default value displayed below the sensitivity variables list, click **Edit** to assign a custom range value.
4. Check **Enable this simulation** to include the sensitivity analysis in simulation runs. You can save the sensitivity simulation setup options and exclude the analysis from simulations by clearing the checkbox. Clearing the checkbox allows you to shorten simulation run times without losing the setup configuration.



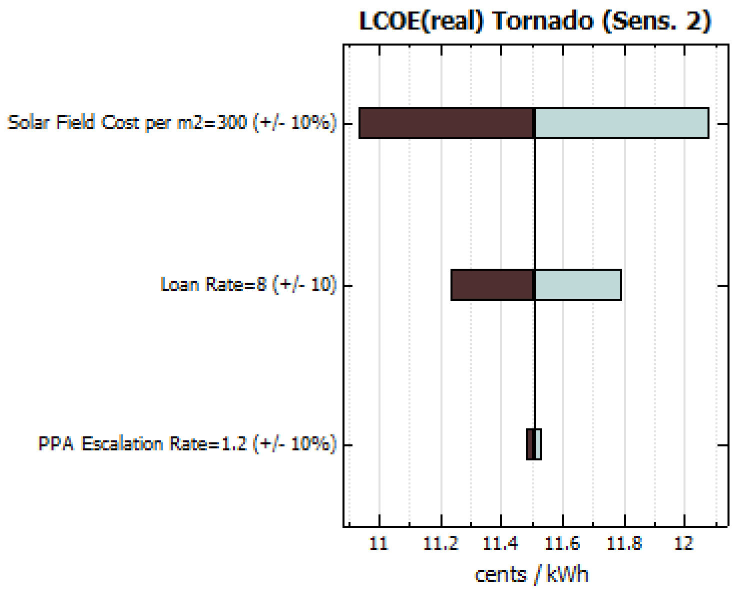
Sample Sensitivity Analysis Results

The following tornado graphs were created by setting up sensitivity analyses. You can use these examples to better understand how to use parametric analysis to create useful graphs.

The following graph shows how sensitive a CSP trough project's levelized cost of energy is to four capital cost categories. To create the graph, the following four variables were defined as sensitivity variables using the default variation range of 10 %: Power plant cost, solar field cost, HTF system cost, and storage system cost:



The next graph shows how sensitive the levelized cost of energy is to selected capital cost categories compared to selected financial assumptions for a CSP trough system. The solar field cost, loan rate, and PPA escalation rate were defined as sensitivity variables with a 10 % variation range. how the first year annual electric output depends on both the array tilt and azimuth. The tilt variable was assigned the same values as the previous graph, and the azimuth variable was assigned values between -90 and 90 degrees west of south in increments of 15 degrees:



25.3 Statistical

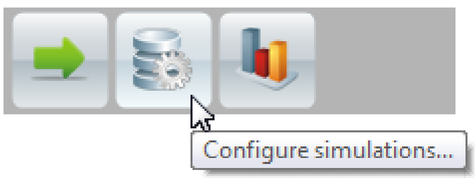
A statistical analysis allows you to examine the effect of uncertainty in the value of one or more input variables on an output metric. For example, you could use statistical analysis to explore how the degree of uncertainty in the installation cost of one or more system components might affect the system's levelized cost of energy over the project life.

In a statistical analysis, SAM runs several simulations for a distribution of values assigned to one or more input variables, and displays a histogram showing the frequency distribution of different output metric values over each input variable's distribution of values.

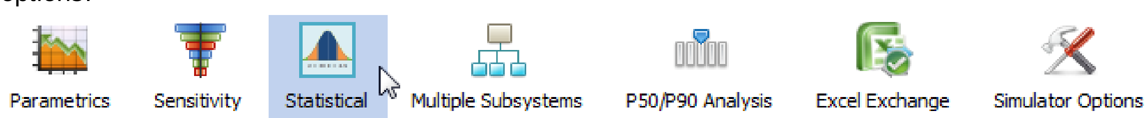
For an example of a SAM file with statistical analysis, open the sample file *Statistical Analysis Sample*: On the File menu, click **Open Sample Template** and select the file from the list.

To display the statistical simulation setup options:

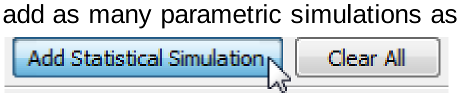
1. On the Main window, click **Configure Simulations** to view the Configure Simulation page.



2. On the Configure Simulations page, click **Statistical** to display the statistical simulation setup options.



3. Click **Add Parametric Simulation** to add a set of parametric simulation setup options. You can add as many parametric simulations as your analysis requires.

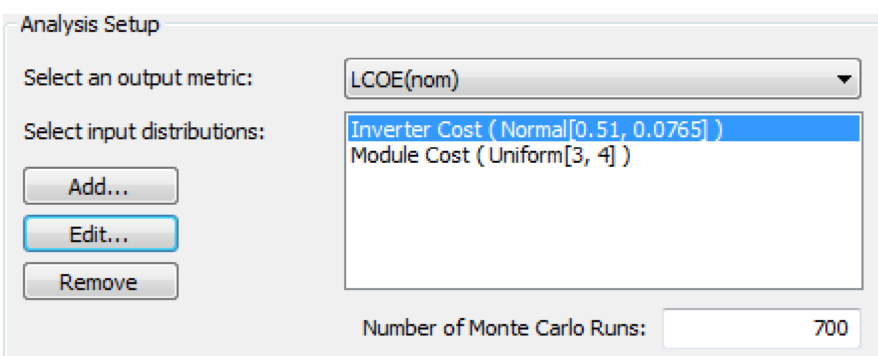


Click **Remove Simulation** to delete an analysis option.

Click **Clear All** to remove all analysis options from the case.

Analysis Setup

The statistical Analysis Setup options allow you to select the output metric, add and remove variables from the list of statistical variables, and assign distribution parameters to the statistical variables.



Select an output metric

Choose the output metric for the statistical analysis.

Add

Choose one or more statistical variables from a list of available input variables.

Edit

Assign an input distribution for the analysis. See below for details.

Remove

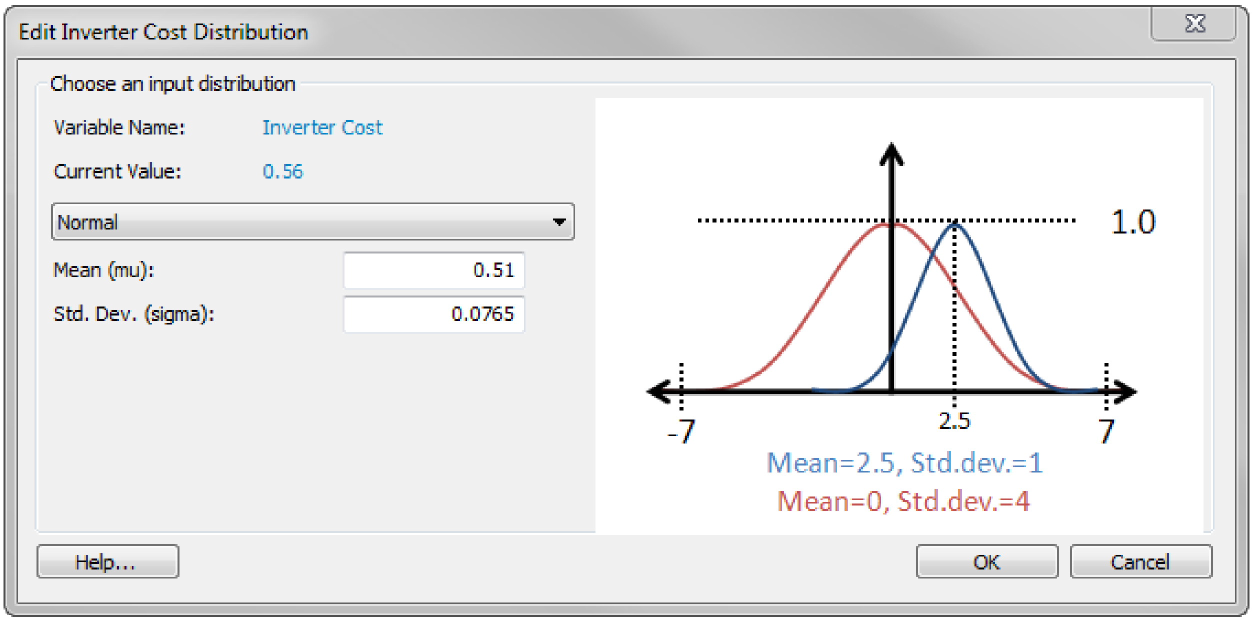
Remove the highlighted variable from the statistical variable list.

Number of Monte Carlo Runs

Enter a value for the number of simulations to run for the analysis. The default value is 400.

Input Distribution Options

The edit distribution window allows you to define the type of distribution to use for the statistical analysis and to assign values to the statistical analysis parameters.



Choose an input distribution

Variable name

The name of the statistical variable. This the variable that was highlighted in the statistical variable list when you clicked Edit.

Current Value

The value of the statistical variable on the variable's input page.

Distribution list

Select from a list of distributions, and SAM displays a description of the distribution and parameters for you to enter.

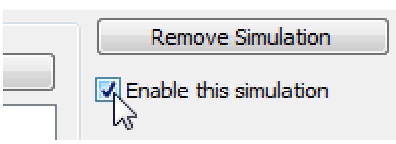
Setting up a Statistical Analysis

Once you have added a statistical simulation, you must choose an output metric for the analysis, add one or more statistical variables to the simulation, and edit the distribution parameters of each variable.

After setting up the optimization, click the Run All Simulations button, or click **Run All Simulations** on the Case menu to run the optimization and any other enabled simulations.

To set up a statistical analysis:

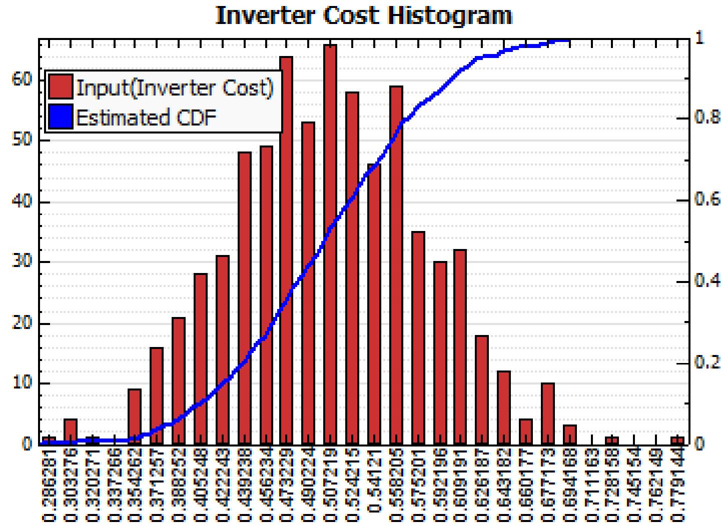
1. Display the statistical simulation setup options as described above.
2. Click **Add** to choose variables to which you want to assign a distribution from a list of available input variables. SAM adds the variables to the parametric variables list.
3. Highlight each variable in the parametric variables list and click **Edit** to assign the distribution parameters.
4. Enter a number of simulations for **Number of sampled values per variable**. SAM will run this many simulations using variable values based on the distribution parameters you specify.
5. Click **Compute Samples** to generate a table of values without running simulations.
6. Check **Enable this simulation** to include the optimization in simulation runs. You can save the optimization setup options and exclude the analysis from simulations by clearing the checkbox. Clearing the checkbox allows you to shorten simulation run times without losing the setup configuration.



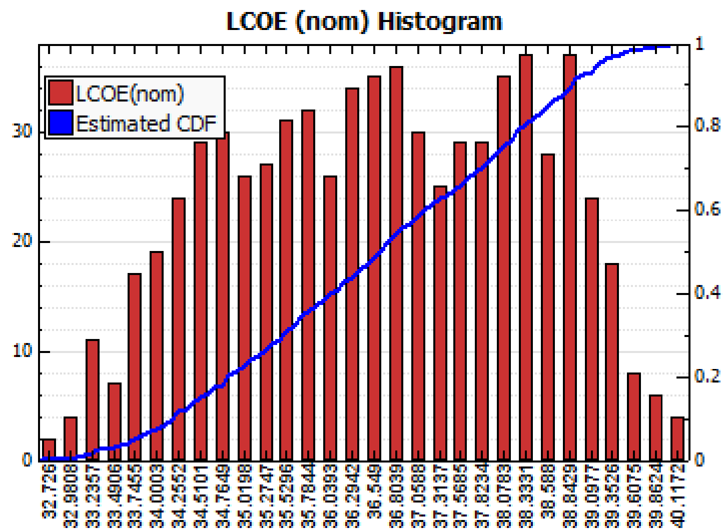
Displaying Histograms for Statistical Variables

After you run all simulations with one or more statistical simulations enabled, SAM allows you to view a histogram for each statistical variable on the Results page. To display a histogram, SAM sorts the values of the simulations into bins. The number of bins is specified in the graph setup.

For example, in the *Statistical Analysis Example* sample file (on the **File** menu, click **Open sample file**), the Inverter Cost histogram shows the number of occurrences of inverter cost that fall into each of the equally spaced bins, whose center values are shown along the x axis. The blue line is the estimated cumulative distribution function (CDF), labeled on the right axis from 0 to 1, and indicates the percentage of inverter cost values whose values fall below the corresponding x value.



The histogram graph can only plot a single variable. Instead of plotting the inverter cost values, you could plot the levelized cost of energy, showing histogram of the 700 calculated LCOE values that correspond to the random values chosen for the Inverter costs. This way, given different amounts of uncertainty in your chosen inputs, you can visualize the effect and uncertainty on any of the single-valued output metrics.



25.4 Multiple Subsystems

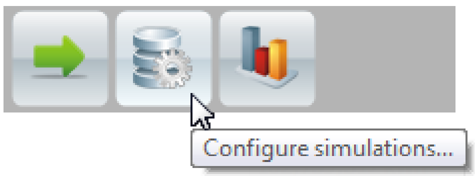
A multiple subsystems analysis allows you to model a power system as a combination of subsystems. This makes it possible to model a photovoltaic system consisting of separate subsystems with arrays oriented in different directions, or a CSP trough system consisting of two separate subsystems with different characteristics. Each subsystem is a complete electricity generating system, which means that for a CSP system for example, each subsystem would include a solar field, storage system, and power generating unit.

SAM applies a single set of financial and incentives inputs to a combined system, but applies separate performance and weather data specifications to each subsystem.

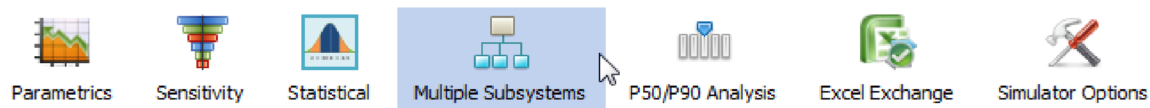
The results such as levelized cost of energy and annual electric output displayed in graphs and tables on the Results page are for the combined system rather than for the individual subsystems.

To display the multiple system simulation setup options:

1. On the Main window, click **Configure Simulations** to view the Configure Simulation page.



2. On the Configure Simulations page, click **Multiple Subsystems** to display the multiple system analysis setup options.



The multiple system setup options allow you to choose which cases in the project file to combine into a system, and display the capacity and cost values for the combined system.

Select Additional Performance Outputs

List of available cases

The list of available cases shows the cases in the project file that you can combine into a single system. You must create a case for each subsystem to be combined into a single system. SAM includes only checked cases in the combined system. The list of cases corresponds to the case tabs in the project file.

Enable this simulation

This box must be checked for the system to be modeled as a combined system.

Aggregate System Variables

The aggregate system variables display values for the combined system that SAM calculates by adding values from the individual subsystems.

Combined Nameplate Capacity (kW)

The sum of the subsystem nameplate capacities for each subsystem. For photovoltaic systems, the nameplate capacity is equivalent to the total array capacity in DC kW. For CSP systems, it is the nominal capacity of the power cycle in kW of electricity.

Combined Heat Rate (MMBtu/MWh)

This applies only to generic systems and is the sum of each subsystem's heat rate from the Power Plant page.

Total Direct Cost ($)

The sum of the total direct cost values displayed on each subsystem's costs page.

Total Installed Cost ($)

The sum of the total installed cost values displayed on each subsystem's costs page.

Total Direct Sales Tax ($)

The sum of the total sales tax values displayed on each subsystem's costs page.

O&M Annual Cost ($/yr)

The sum of the fixed annual operation and maintenance costs displayed on each subsystem's costs page.

O&M Annual Capacity Cost ($/kW-yr)

The sum of the fixed annual operation and maintenance costs displayed on each subsystem's costs page.

O&M Variable by Production ($/MWh)

The sum of the fixed annual operation and maintenance costs displayed on each subsystem's costs page.

Setting up a Multiple Subsystems Analysis

Setting up a multiple system analysis involves creating a case for each subsystem to be combined, and then selecting the cases to be included in the multiple system analysis.

After setting up the analysis, click the Run All Simulations button, or click **Run All Simulations** on the Case menu to simulated the combined system..

To set up a multiple subsystems analysis:

1. Create a case for each subsystem to be included in the combined system.
2. Display the case that you want to be the primary system.

   SAM will apply the input variables on the Utility Rate, Financing, Incentives, and Depreciation pages from the primary system to the combined system. It will ignore input values on those pages from the subsystems.
3. Display the multiple system analysis setup options as described above.
4. Under **Select Additional Performance Outputs**, check each case to include in the combined system, including the current (primary) case indicated by "This case is required" in parentheses next to the case name.

   SAM displays the combined system nameplate capacity and costs under **Aggregate System Variables**.
5. Check **Enable this simulation** to include the multiple system analysis in simulation runs. You can save the parametric simulation setup options and exclude the analysis from simulations by clearing the checkbox. Clearing the checkbox allows you to shorten simulation run times without losing the setup configuration.

25.5 Excel Exchange

SAM allows you to connect any input variable in SAM to a cell or range of cells in a Microsoft Excel workbook. This feature allows you to use external spreadsheet-based models to generate values for SAM input variables.

Because SAM can both import values from a worksheet and export values to them, you can use the result of a worksheet formula as the value of one SAM input variable that depends on the value of other input variables.

User variables are user-defined input variables that can also share values with external workbooks.

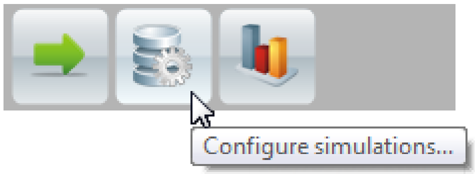
Note for Mac users. SAM can not exchange data with Microsoft Excel on Mac computers. This means that the Excel Exchange feature is disabled on Mac versions of the software, and that SAM cannot directly export data to Excel workbooks.

To use the SAM data in Excel or another spreadsheet program, you can export the data to a comma-separated text file (CSV), and then import the CSV file to the spreadsheet program.

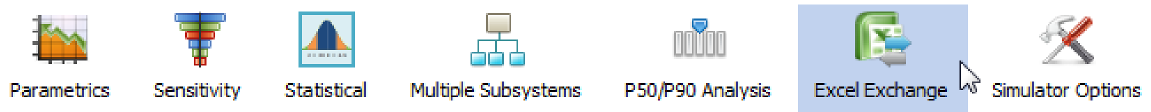
For an example of a SAM file with Excel Exchange, open the *Excel Exchange Example* sample file: On the **File** menu, click **Open sample file** and select the file from the list. The example uses a spreadsheet to calculate a first-year operation and maintenance value in $/kW-year

To display the Excel data exchange setup options:

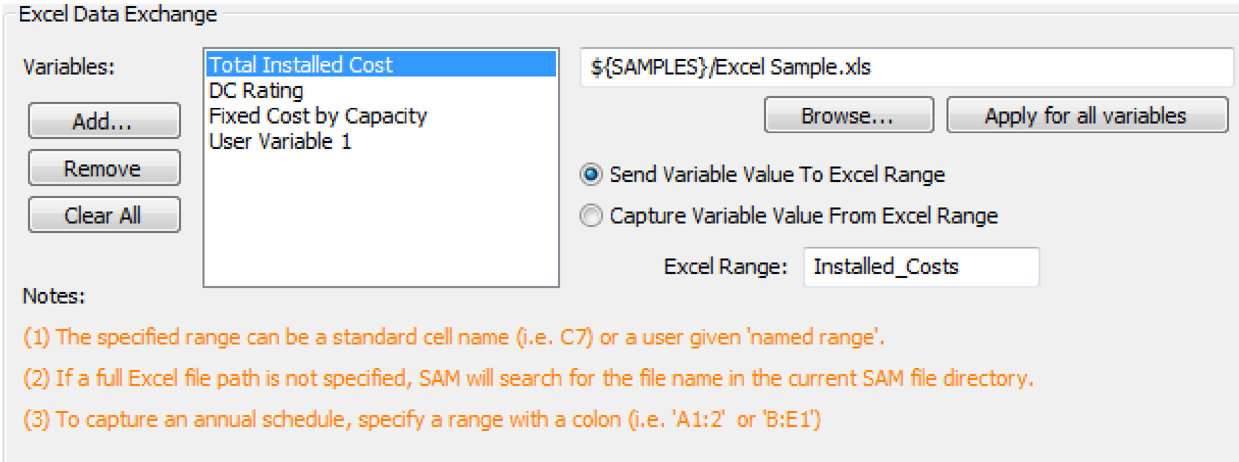
1. On the Main window, click **Configure Simulations** to view the Configure Simulation page.



2. On the Configure Simulations page, click Excel Exchange to display the Excel data exchange options.



The Excel Data Exchange options allow you to add and remove SAM input variables to the list of variables to exchange data with Excel, specify the Excel workbook with which to exchange data, and for each input variable, define the relationship with a cell or range of cells in the workbook.



Notes.

When you run simulations with Excel Exchange, SAM opens a copy of the Excel file to read and write values but does not save the file. If you open the Excel file after running the simulations, you will not see any values from the SAM in the Excel file.

Excel Exchange works with both *.xls* and *.xlsx* files.

If the Excel workbook contains more than one worksheet, SAM can only exchange data with the first worksheet (the worksheet whose tab appears is the leftmost tab).

Excel Data Exchange

Add

Add one or more input variable from the input pages. You can configure each variable to either send a value to an Excel range, or "capture" a value from an Excel range.

Remove

Delete the highlighted variable from the list.

Clear All

Delete all variables from the list.

Browse

Browse your computer's folders to find the Excel workbook with which you want to exchange data. The workbook can be located in any folder on your computer.

Apply for all variables

When all of the variables are in a single Excel file, you can click this button to avoid having to retype the file name for each variable.

Send Variable Value to Excel Range

Configure the highlighted variable to send its value to the specified Excel range.

Capture Variable Value From Excel Range

Configure the highlighted variable to capture its value from the specified Excel range.

Excel Range

The range name or cell reference identifying the cell or range of cells in the Excel workbook with which the highlighted variable will exchange data.

Enable this simulation

This box must be checked for the analysis to exchange data with Excel.

Annual Schedules and Excel Exchange

For input variables that you specify with an annual schedule that contains a table of values, you must specify a range of cells using cell references rather than a named range. For example, if you want to specify

25.6 P50/P90 Analysis

A P90 value is a value that is expected to be met or exceeded 90% of the time. SAM can generate P50 and P90 values for a system's annual energy output and other metrics by running hourly simulations over a multi-year period.

Notes.

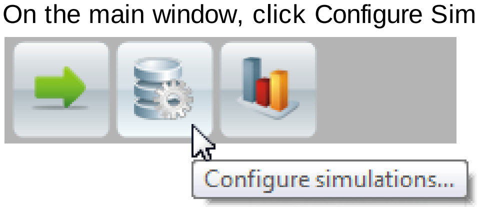
Because a P50/P90 analysis involves running simulations for multiple years, depending on the type of system you are simulating, it may take several minutes to complete a P50/P90 simulation run.

The **year-to-year decline** in output value on the Performance Adjustment page does not affect the Net Annual Energy values that SAM reports in the P50/P90 analysis results. However it does affect the LCOE value because SAM calculates the LCOE over the analysis period for each weather file year and applies the year-to-year decline value to calculate the annual system output over the analysis period.

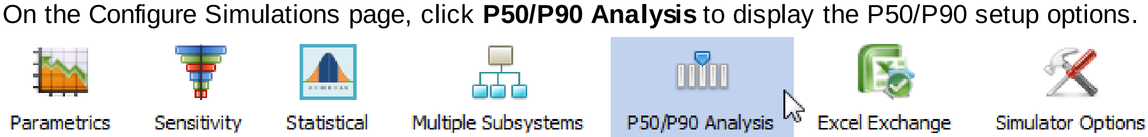
For a description of SAM's P50/P90 methodology, see Dobos, A. P.; Gilman, P.; Kasberg, M. (2012). P50/P90 Analysis for Solar Energy Systems Using the System Advisor Model: Preprint. 8 pp.; NREL Report No. CP-6A20-54488. (PDF 372 KB)

To display the P50/P90 analysis setup options:

1. On the main window, click Configure Simulations to view the Configure Simulations page.



2. On the Configure Simulations page, click **P50/P90 Analysis** to display the P50/P90 setup options.



P50/P90 Analysis

The P50/P90 Analysis setup options allow you to select your weather information database file, search for a location within that database, select your location, and enable or disable P50/P90 analysis simulation. SAM uses the .cbwfdb file format for P50/P90 analysis.

Enable P50/P90 Analysis

The P50/P90 analysis simulation will only run if this box is checked.

Weather database file

The full weather database file's name and path.

Filter

Type a few characters of a location name or station ID to find files from the database, and click the location to select the location for which you want to run a P50/P90 analysis.

Downloading the Full Weather Database File

The P50/P90 analysis capability requires a special weather file containing multi-year solar irradiance and meteorological data. SAM comes with a few sample locations pre-installed. For more locations, you can download the full weather database file. The full weather database file contains data for many U.S. locations.

Note. You only need to download the full weather database file once.

To download the full weather database file:

1. Click the link on the P50/P90 analysis page, or go to http://en.openei.org/datasets/node/872.
2. Download the database file (about 1.3 GB, with the .cbwfdb extension) and save it to a folder on your computer.
3. Click the **Weather database file** ... button and navigate to the folder containing the file.
4. A list of locations in the database will appear in the box below the search filter.

Using Single Year Weather Files

If you have 15 or more single year weather files for a series of years, you can use them for P50/P90 analysis. The files must be in one of the weather file formats that SAM can read and use the naming convention described in the following procedure.

To prepare a series of single year weather files for P50/P90 analysis:

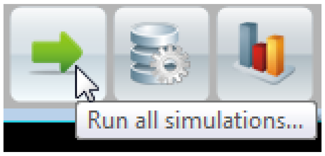
1. Rename each weather file using the following convention: *<place name>_<year>.<extension>*. For example, *paris_1950.tm2*, *paris_1951.tm2*, etc.
2. Place all of the files in a single folder.
3. Check **Use standard weather files in folder to run P50/P90 analysis**.
4. For **Path**, navigate to the folder containing the files.

Setting up and running up a P50/P90 Analysis

After you have downloaded the full weather database file, you can set up and run a P50/P90 analysis.

To set up and run a P50/P90 Analysis:

1. Click **Enable P50/P90 Analysis**.
2. Click the name of the location in the list of available locations. You can type a few letters of the location name or ID, or use the scroll bar to find your location.
3. Note the number of years displayed under the location list. This is the number of years for which there is a complete set of solar irradiance and meteorological data.
4. After specifying the inputs for your analysis, click the Run button.



5. After running simulations, SAM displays P90 values for each metric in the Metrics table on the Results page, and additional results in Tables and Graphs.

Viewing P50/P90 Analysis Results

SAM runs a simulation for between 15 and 45 years based on real hourly weather data for your selected location. The number of years simulated depends on the data weather data that is available for that location.

To view P50/P90 Analysis Results

1. After running simulations, on the Results page, click **Tables**.
2. For **Choose Simulation**, click **P50/P90 Analysis**.
3. To view statistical summaries of the multiple-year data, Under **Output Variables**, click **Single Values**.
4. To view annual results for each year, click **Data:45 values** (the number of values, in this example, 45, depends on the number of years included in the database).

Output Variables

When you run a P50/P90 simulation, SAM calculates and displays two forms of the P50 and P90 values (see description below), minimum, maximum, and standard deviation for each metric that appears in the Metrics table on the Results page.

SAM uses two methods to calculate these values: The normal distribution method (P50n and P90n) and the empirical (P50e and P90e) method:

- For the normal distribution method, SAM creates a normal distribution by calculating the mean and standard deviation of simulated results (annual energy, LCOE, etc.). SAM calculates the P50 and P90 values from that normal distribution. This method works well if the data is normally distributed. If the data is not normally distributed, this method may produce incorrect results, and the empirical P50 and P90 values should be used instead.
- For the empirical method, SAM determines P50 and P90 values by sorting the empirical cumulative distribution function (CDF) into increasing order. This method does not make any assumptions about the distribution of the data, so it works well even if the data is not normally distributed.

Graphs

When you run a P50/P90 simulation, SAM automatically generates the following graphs:

- Annual Energy (P50/P90 Analysis) shows the annual energy produced each year over the entire P50/

P90 simulation, in temporal order.

- Sorted Annual Energy (P50/P90 Analysis) shows the same data, but it is sorted by the annual energy produced.
- Histogram/CDF (P50/P90 Analysis) shows you a histogram and CDF of the simulated annual energy data on the same plot surface. This plot is useful because it is a visual representation of the way the simulated data is distributed.
- Annual Energy (P50/P90 Analysis) shows the maximum and minimum simulated annual energy values, plotted alongside the P90 and P50 values. This graph lets you compare these values side-by-side.
- LCOE (P50/P90 Analysis) shows the LCOE for each year that was simulated. This shows you how the LCOE might vary from year to year.

26 Advanced Modeling Topics

Advanced topics include the following features:

- Libraries: View SAM's parameter databases, and add custom parameter databases.
- Simulator Options: Change the simulation time step or use a custom TRNSYS deck.

26.1 Libraries

Contents

- Accessing Libraries from Input Pages explains how to use libraries to populate input variables on input pages.
- Library Descriptions describes the libraries in the current version of SAM and the input pages that display values from each library.
- Default and User Libraries explains the difference between libraries that come with the software, and libraries that you add to your projects.

A library is a collection of stored values for groups of input variables that characterize a system component, heat transfer fluid, or fuel, or describe a set of adjustment factors. SAM displays each library as a list on the appropriate input page. For example, the Sandia inverter library stores a set of input values for each inverter in the California Energy Commission's inverter database. SAM displays the library as a list of inverter names on the Inverter page with the Inverter CEC Database model option. When you choose an inverter from the list, SAM populates the input variables on the Inverter page with values from the library. See Accessing Libraries from Input Pages for details.

For advanced analyses, you may want to add your own entries to a library, or to modify entries in an existing library. Or, you may want to export the data in a library to a text file. The library editor allows you to manage and export data from libraries. You should only add or modify a library entry when you have a complete set of data for the entry. Because values in the entry may be interdependent in ways that are not obvious, you can easily introduce errors to simulation results by changing values in a library entry. An obvious example would be changing one of the power values for an entry in the inverter library without changing the current and voltage values. In general, you should not modify libraries unless you are familiar with both the characterization of the physical component represented by library entries, and with SAM's mathematical representation of the component.

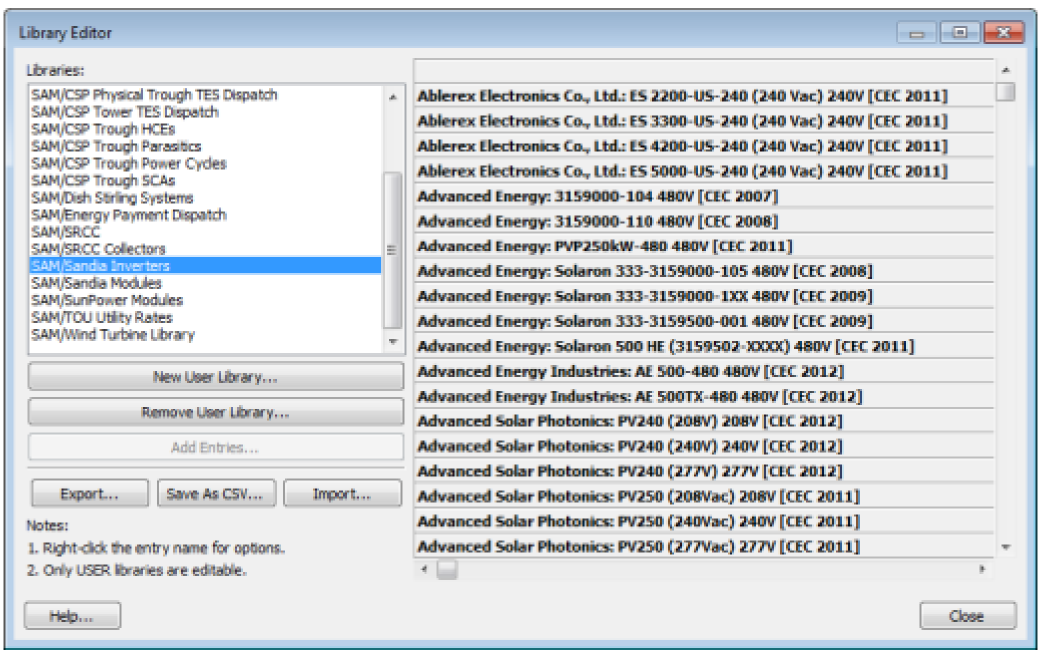
Note. If you decide to modify or create your own libraries, you should first read about the difference between default and user libraries, and refer to the instructions for working with the library editor.

You cannot edit default libraries from the library editor. To edit a default library, you can either create a copy of the library as a user library (the recommended approach), or you can edit the file directly using a text editor. See Default and User Libraries for details.

To open the library editor:

- On the Tools menu, click **Library Editor**.

Note. In order for the library editor to be fully functional, you must open a SAM file before opening the library editor. If you open the library editor from SAM's welcome page, only the export function is active.



Libraries

Shows the list of default libraries with the prefix "SAM/" and any user libraries in the project with the prefix "USER/". Click a library name to display the library's contents. Each library entry is a row in the table.

New User Library

Click to add a new user library to the project. SAM stores user library data in the project file rather than in external library files.

Remove User Library

Click to remove a user library. You cannot remove a default library indicated by the "SAM/" prefix.

Add Entries

Add rows of data to a user library. You must choose a user library indicated by the "USER/" prefix before adding entries. You cannot add entries to a default library with the "SAM/" prefix.

Export

Export the current library to a library file (*.samlib*). Export a library when you want to use it in a different project. You must import the library into the other project for it to be available in that project. You can export a library to the default library folder (*/exelib/libraries* in your SAM installation folder) to make the library available to all SAM projects on your computer.

Save As CSV

Export the current library to a comma-separated values (CSV) text file. You can then open the file in a spreadsheet program or text editor.

Import

Create a new user library by importing entries from a library file (*.samlib*). When you import a library, SAM stores the library entries in the project file, which affects the file's size.

Help

Display the Libraries help topic.

Close

Close the library editor.

To create a new user library:

1. Open the library editor.
2. Click **New User Library**.
3. Type a name for the library in the Import Library window. This is the name that will appear in library lists.
4. Choose a library type in the New User Library window. See the table of library types for type descriptions.

When you create a new user library, SAM adds an empty library with the name you specified and the prefix "USER/" to the list of libraries. To assign values to the entry, you must first add a copy of an existing entry, and then modify its values. This helps to ensure that no library entries have blank values.

To add entries to a new or existing user library:

1. Click the user library's name in the Libraries list. User libraries are indicated by the prefix "USER/".
2. Click **Add Entries**.
3. In the Copy Existing Entry window, check one or more items that have similar characteristics to the entry you want to add.
4. Click **OK**.
5. To rename a library entry, in the library table, right-click the entry's name, and choose **Rename** from the shortcut menu.
6. To add values to a library entry, you can either

change values manually by double-clicking each cell and typing a value, or

copy a row of values from a comma-separated text file or Excel worksheet file, and then right clicking the library entry's name and choosing **Paste Values** in the shortcut menu.

Note. The library editor does no error checking, so be sure to use valid values in your library entries.

To modify values in a default library:

1. Create a new user library of the same type as the default library (see instructions above).
2. Add the entry that contains the values you want to modify from the default library and change the value (see instructions above).

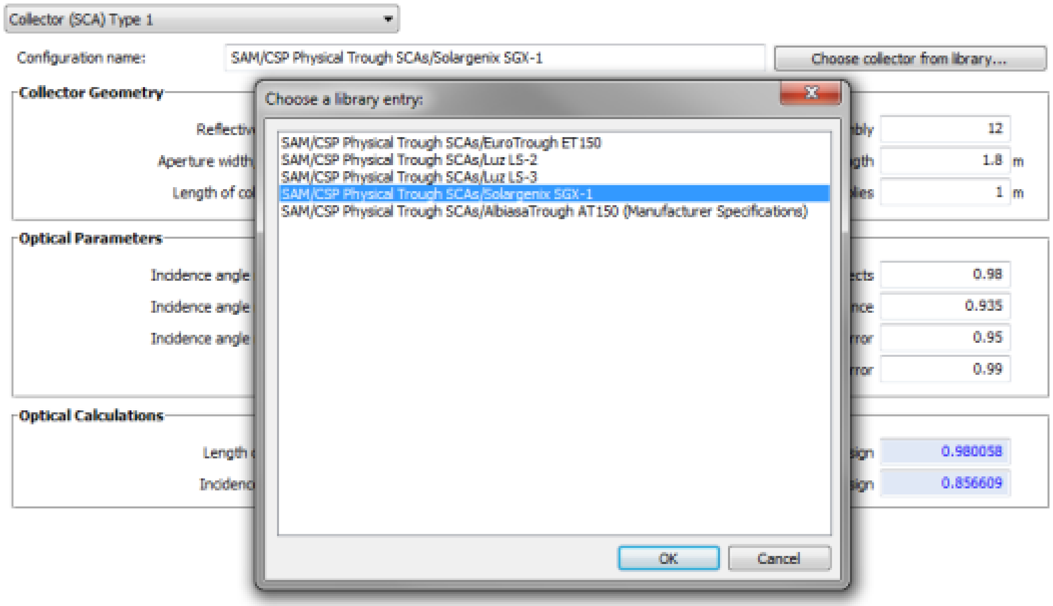
Note. You can also use a text editor to change values directly in a default library. You should only use this approach if you are very familiar with the parameters stored in the library, and are certain that you want to discard the original values stored in the library. We recommend only modifying copies of libraries. See Default and User Libraries for file location details.

To "convert" a user library to a default library:

1. Click user library's name in the Libraries list.
2. Click **Export** and save the file in the libraries folder (*/exelib/libraries* in your SAM installation folder).
3. SAM will display the library with the "SAM/" prefix, and make it available to all SAM projects on your computer.

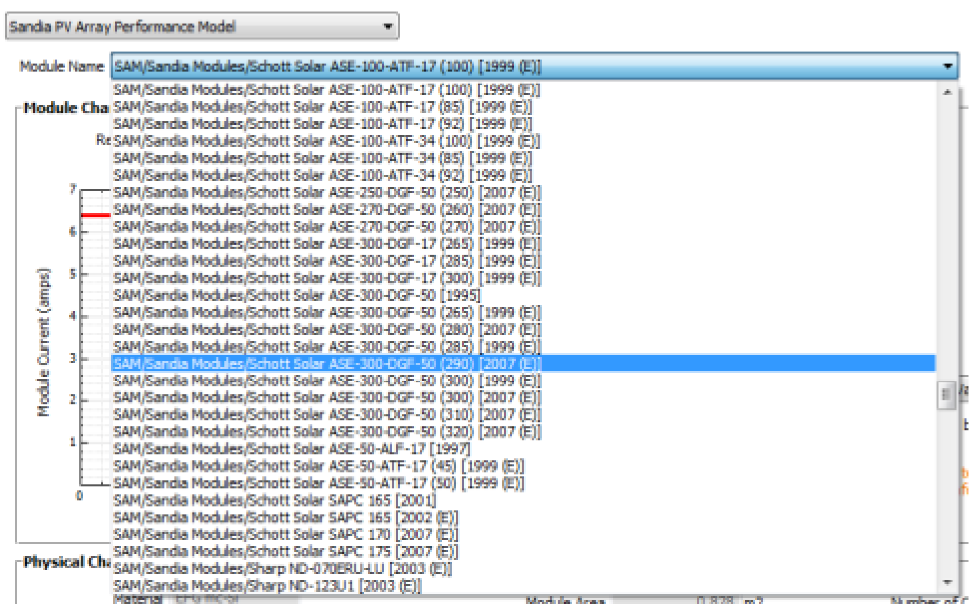
Accessing Libraries from Input Pages

Depending on the library, SAM either displays a "Choose from library" or "Library" button, or displays the library entries as a list directly on the input page. For some components, to choose an item from a library, you click the Choose (or Library) button and then click the item's name in a list of library items. SAM automatically populates appropriate variables on the input page, which you can edit if necessary. For example, on the physical trough model's Collectors page, to choose an entry from the parabolic trough collector library, click **Choose collector from library**. SAM displays a list of collectors from the library. When you click a collector name in the list, SAM copies collector geometry and optical parameter values from the library to the variables on the Collectors page.



If you change the value of one of those variables, SAM indicates that the parameters on the input page differ from parameter values in the library by displaying "No library match" in the library name box:

For other libraries, such as the Flat Plate PV model's Sandia module library, SAM displays the list of library items directly on the input page. When you choose an item from the list, SAM copies values from the library to the project's case, and displays some of them as read-only values on the Module page. If you want to use change a value, you must create a new user library.



> **Note.** SAM often only displays a subset of the parameters from a library on input pages. If you want to see the complete parameter set for a library item, you can view the values in the library editor.

Library Descriptions

SAM uses libraries to store parameter sets for the following performance model components and displays them as lists on the relevant input pages.

BIOBIB Fuels

Not used.

CEC Modules

List of photovoltaic modules from the California Energy Commission database of approved modules for the flat plate photovoltaic model, displayed on the Module page when the CEC Performance Model with Module Database option is active.

CSP Empirical Trough TES Dispatch

Storage dispatch schedules based on time-of-use rates of different electric utilities for the empirical trough model displayed on the Thermal Storage page.

CSP GSS TES Dispatch

Storage dispatch schedules based on time-of-use rates of different electric utilities for the generic solar system model displayed on the Thermal Storage page.

CSP Physical Trough Receiver (HCE)

Receiver characteristics for the physical trough model displayed on the Receivers (HCEs) page.

CSP Physical Trough SCAs

Collector characteristics for the physical trough model displayed on the Collectors (SCAs) page.

CSP Physical Trough TES Dispatch

Storage dispatch schedules based on time-of-use rates of different electric utilities for the physical trough model displayed on the Thermal Storage page.

CSP Tower TES Dispatch

Storage dispatch schedules based on time-of-use rates of different electric utilities for the power tower model displayed on the Thermal Storage page.

CSP Trough HCEs

Receiver characteristic for the empirical trough model displayed on the SCA/HCE page.

CSP Trough Parasitics

Parasitic loss coefficients for different reference power cycle options of the empirical trough model displayed on the Parasitics page.

CSP Trough Power Cycles

Steam turbine characteristics for different reference power cycle options of the empirical trough model displayed on the Power Block page.

CSP Trough SCAs

Collector characteristics for the empirical trough model displayed on the SCA/HCE page.

Dish Stirling Systems

Complete system descriptions for the dish-Stirling model displayed on the System Library page.

Energy Payment Dispatch

TOD factors and schedules displayed on the Time of Delivery Factors page.

SRCC

List of solar water heating collectors displayed on the SWH System page.

Sandia Inverters

List of inverters from the California Energy Commissions inverter database for the flat plate photovoltaic model, displayed on the Inverter page when the Inverter Database model option is active.

Sandia Modules

List of modules from the Sandia module database for the flat plate photovoltaic model, displayed on the Module page when the Sandia PV Array Performance Model with Module Database option is active.

SunPower Modules

List of SunPower modules with Sandia photovoltaic module model parameters provided by the SunPower Corporation, displayed on the Module page when the Sandia PV Array Performance Model with Module Database is active.

TOU Utility Rates

Retail time-of-use rates for projects with residential or commercial financing displayed on the Utility Rate page.

Wind Turbine Library

List of wind turbines for the wind power model displayed on the Turbine page.

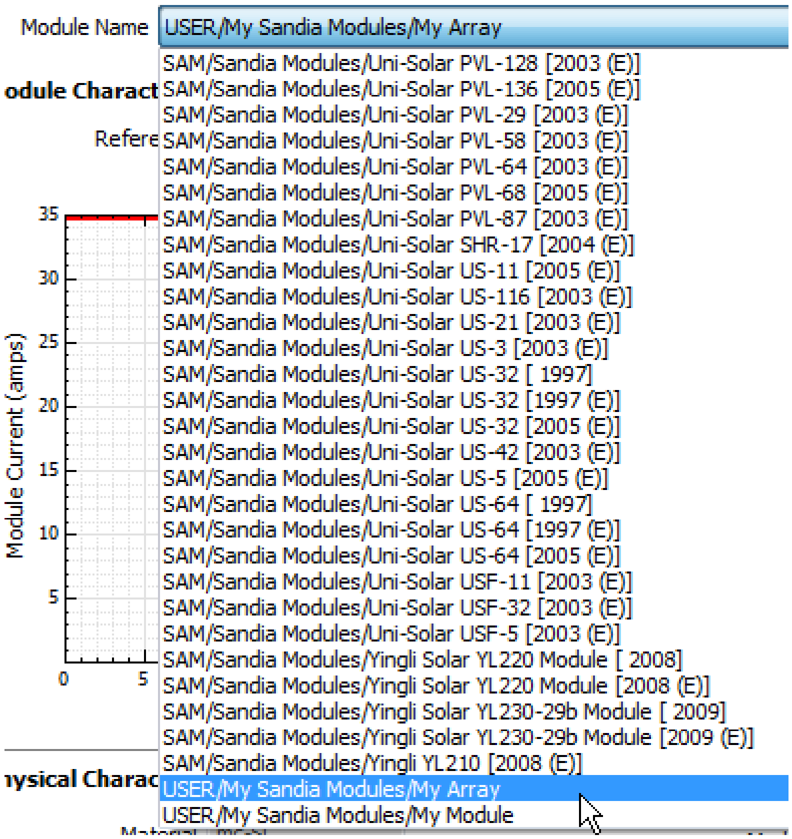
Default and User Libraries

SAM stores data for each library in library files. A library file is a text file with a the *.samlib* extension. You can find the library files in the library folder (*/exelib/libraries* in your SAM installation folder). SAM uses a library type definition file with the *.samlibtype* extension to map values from the library file to SAM input variables.

There are two types of libraries, default libraries indicated in lists by the prefix "SAM/" in lists, and user libraries indicated by the prefix "USER/":

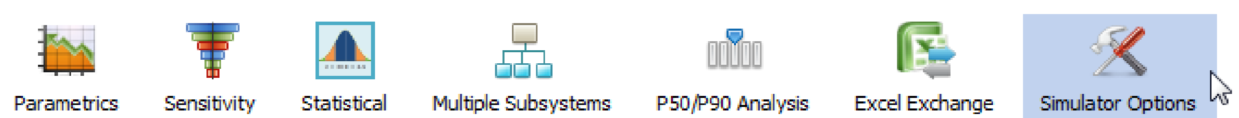
- Default libraries are available to all project files on your computer and cannot be modified from the library editor. SAM considers any library file stored in the library folder to be a default library, and indicates default libraries in lists on input pages with the prefix "SAM/." Although you can use a text editor to modify a default library, we recommend using the library editor to create a copy of the default library for editing so that you always have a copy of the original default library that came with SAM. Note that you can add your own library to the default collection by creating a library file and putting it the libraries folder.
- User libraries are libraries stored in the project file. A user library must be added to a project file to be available in the file. User libraries are indicated in lists by the prefix "USER/." Unlike default libraries, user library parameters are stored in the project file and can increase the project file size. To make a user library available to more than one SAM project on your computer, you can either export it as a library file and then import it into other projects, or you can export to the default library folder so that it is available to all projects on your computer.

SAM displays user libraries at the end of the list. For example, the modules from the user library for the Sandia PV module model appear at the end of the list of modules:



26.2 Simulator Options

The Simulator Options are for advanced analyses that involve either changing the simulation time step, or working with custom TRNSYS input decks.



TRNSYS Simulation Timestep

For some technologies, you can adjust the simulation time step from the default hourly (60 minute) time step. Using a smaller time step than one hour is most appropriate for the physical trough model when you want to explore the effects of sub-hourly changes in dispatch of energy from the solar field and thermal energy storage system.

Note. Changing the simulation time step does not affect the weather data time step. When you use a smaller than hourly time step, SAM uses interpolation of the hourly weather data to estimate the solar resource and other weather parameters at the sub-hourly time points.

TRNSYS Executable and Input Deck

You can use these options to use custom TRNSYS components with SAM. Leave the values blank to use SAM's default TRNSYS components.

Deck file name

The path and name of the TRNSYS deck file for your custom component

TRNSYS executable

The path and name of the TRNSYS executable file with arguments.

Arguments

Arguments for the TNRSYS executable you specify above.

26.3 Exchange Variables

The Exchange Variables page displays two types of special variables. SAM only uses these variables under special conditions -- you can ignore the exchange variables for most analyses.

To view the Exchange Variables page, click **Exchange Variables** on the main window's navigation menu. The user variable input page is available for all technologies.

Note. The **Name and units** text boxes are ignored by SAM. You can use the boxes to help you remember what each user variable represents.

General Purpose User Variables

A general purpose user variable is a variable that you can create to store values in SAM for advanced analyses. SAM stores values of user variables but does not use them in any internal calculations. You can create up to ten user variables.

One application of user variables is to enhance analyses that involve exchanging data with Excel. You can connect user variables, like other input variables, to cells in an Excel workbook. For example, you could use a user variable to convert units using a formula in Excel. You can use the general purpose user variables in parametric and sensitivity analyses.

TRNSYS System Simulation Input User Variables

The system variables are for TRNSYS programmers. You can use the system variables to store values in the SAM user interface that interact with a customized TRNSYS input deck.

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- SolarPACES, International Energy Agency: http://www.solarpaces.org
- U.S. Department of Energy Solar Energy Technologies Program: http://www1.eere.energy.gov/solar
- Database of State Incentives for Renewables and Efficiency at http://www.dsireusa.org

National Renewable Energy Laboratory

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