

California Energy Commission
STAFF REPORT

Cost of Generation User's Guide Version 3

Based on Version 3.98 of the Cost of Generation Model

California Energy Commission

Edmund G. Brown Jr., Governor

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ABSTRACT

The *Cost of Generation Model User's Guide* is a manual for the California Energy Commission's Cost of Generation Model. It provides an understanding of how the Cost of Generation Model operates, the features that are available to the user, and some of the underlying calculations that drive the model.

The primary function of the model is to calculate levelized costs—the total costs of building and operating a power plant over the economic life converted to equal annual payments in dollars per megawatt-hour and dollars per kilowatt-year-for utility-scale electric generating technologies. These are the costs as seen by the developer; they do not account for system costs nor do they reflect the interaction of the technology with the electrical generation system. The primary internal use of the Cost of Generation Model is to provide levelized costs and supporting data assumptions for use in energy program studies at the Energy Commission and other state agencies.

The present version of the Cost of Generation Model has preset data for 19 central station generation technologies—5 gas-fired and 14 renewable technologies—but can accommodate an almost unlimited number of other technologies, as well as modified scenario data on existing technologies. This version of the Cost of Generation Model improves on earlier versions. Most important, it assesses high and low levelized cost ranges using probabilistic analysis provided by Lumina's Analytica Model.

Keywords: Cost of Generation, levelized cost, instant cost, overnight cost, installed cost, fixed operation and maintenance, O&M, fixed costs, variable costs, heat rate, transformer losses, transmission losses, technology, annual, alternative technologies, renewable technologies, combined cycle, simple cycle, combustion turbine, integrated gasification, coal, fuel, natural gas, nuclear fuel, capacity degradation, heat rate degradation, financial variables, capital cost structure, screening curves, sensitivity curves, risk factors, cost variations, modeling algorithms, electric generation definitions, asset rental prices

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EXECUTIVE SUMMARY

The Cost of Generation Model was first developed for the California Energy Commission's *2003 Integrated Energy Policy Report* and was subsequently updated for the 2007, 2009, and 2013 policy report cycles. This user's guide is the manual for the Cost of Generation Model used in the *2013 Integrated Energy Policy Report* proceeding to develop the *2013 Estimated Cost of New Renewable and Fossil Generation In California Report*. The Cost of Generation Model is posted online as an attachment to the Cost of Generation Report, Publication Number CEC-200-2014-003-SF.

The Cost of Generation Model is a Microsoft Excel® spreadsheet model that calculates levelized cost of energy for utility-scale electric generating technologies (power plants 20 megawatts in size or greater that are used to meet the demand served by California's electric grid). Levelized costs are provided in both capacity (dollars per kilowatt-year) and energy (dollars per megawatt-hour).

The worksheets of the Cost of Generation Model can be visualized as follows: the income statement worksheets (cash-flow and revenue requirement) as models, the input-output worksheet as the control module that also summarizes the results, and the remaining worksheets as data inputs and assumptions. The Cost of Generation Model operates by calculating total levelized costs, which are the sum of the following fixed and variable cost components:

Fixed Costs:

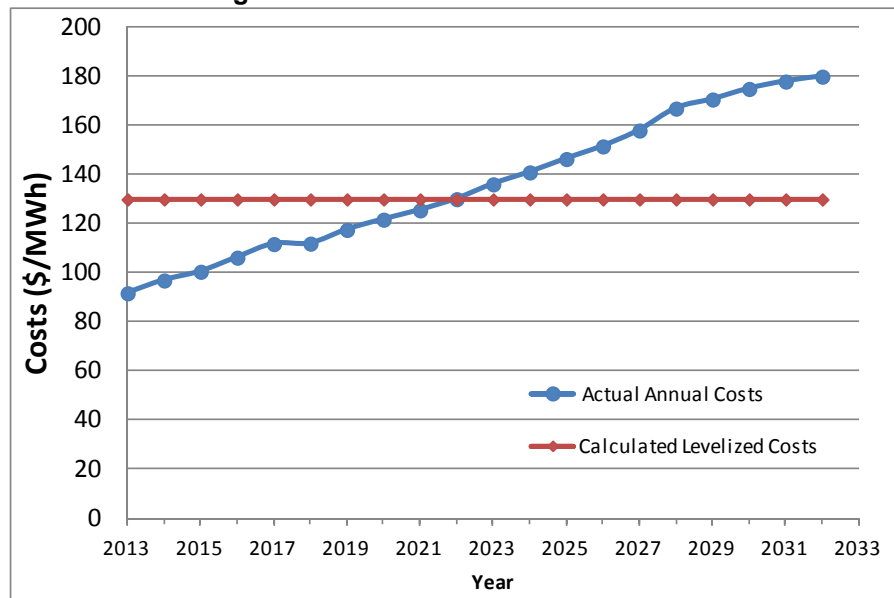
- Capital and Financing—total cost of equipment, construction, and plant financing.
- Insurance—cost of insuring the power plant over the operational lifetime.
- Ad Valorem—property taxes.
- Fixed Operation and Maintenance—staffing and other costs that are independent of operating hours.
- Corporate Taxes—state and federal taxes.

Variable Costs:

- Fuel Cost—cost of the fuel used, including emission costs.
- Variable Operation and Maintenance—operation and maintenance costs that are a function of the number of operating hours.

Using dozens of cost, financial, and tax assumptions, the Cost of Generation Model calculates the costs for a technology on an annual basis, finds a present value of those annual costs, and then calculates the levelized cost thereof. These results are presented as a cost per unit of generation over the period under investigation. These calculations are done by dividing the costs by the sum of all the expected generation over the time horizon being analyzed. The most common presentation of levelized costs is in dollars per megawatt-hour, but they are sometimes presented as dollars per kilowatt-year. **Figure 1** illustrates the relationship between the actual annual costs and calculated levelized cost of energy.

Figure 1: Illustration of Levelized Costs



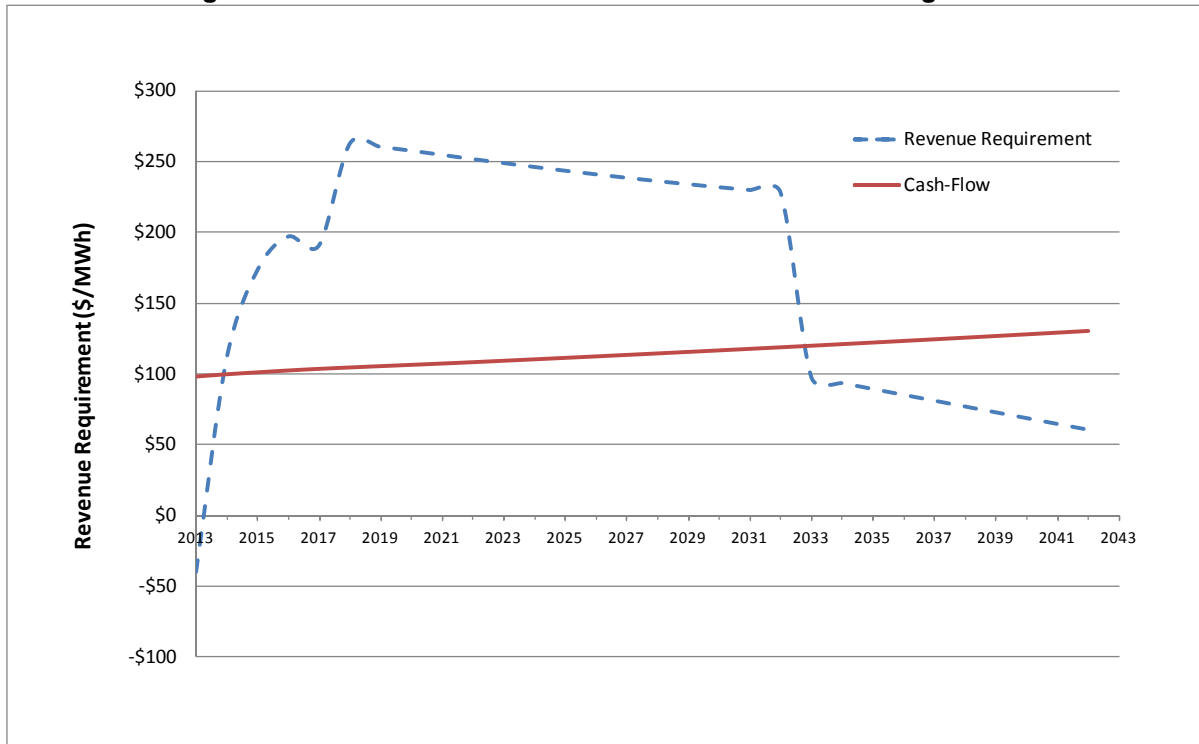
Source: Energy Commission.

All these estimates are calculated as a function of who the developer is: merchant, investor-owned utility, or publicly owned utility. The financing costs are particularly different for the three developers. Publicly owned utilities finance solely through debt, whereas merchant and investor-owned utilities raise money through debt and equity (stocks). Each developer type makes debt and equity payments in different ways. Debt payments are constant for merchant plants but a function of book value for investor-owned utilities. Equity payments for merchant plants are calculated based on cash-flow accounting but are based on revenue requirement accounting for investor-owned utilities. Capital financing and corporate taxes are more complicated in that the amount of financing cannot be estimated without knowing the taxes, and the taxes cannot be known until amount of financing is known. The Cost of Generation Model assumes that the revenue requirement is just adequate to cover all costs. This interdependence requires simultaneous equations. These equations are built into the income statements, which are used to calculate the levelized cost of energy for investor-owned utilities and merchant developers. Since publicly owned utilities do not have taxes, the related levelized costs of energy are determined using the revenue requirement income sheet.

The key difference between revenue requirement and cash-flow is in how the equity payments are calculated. This calculation affects only the fixed costs in only two categories: Capital and Financing Cost and Corporate Taxes (state and federal taxes).

Figure 2 illustrates the difference in the annual costs of cash-flow vs. revenue requirements for a 100 MW solar PV single-axis technology, going on-line in 2013.

Figure 2: Annual Revenue Stream for 100 MW Solar PV Single Axis



Source: Energy Commission.

While levelized costs of energy, as well as installed costs, will differ based on the developer, instant costs will not. All plant type assumptions are inputted as *instant costs*. These costs include the equipment, land, permitting, licensing, and construction (overnight). *Installed costs* are the instant costs plus construction costs (financing), and developmental costs (predevelopment expenses, construction insurance and installation, commitment fee, and debt arrangement fees). Levelized cost includes these fixed costs plus insurance, fixed operations and maintenance, ad valorem, and variable costs.

Model Features

The Cost of Generation Model has several features in addition to levelized cost of energy. It includes the ability to model all physical features, including power plant and transmission interconnection losses, capacity and heat rate degradation, and emission factors. It provides a breakdown of costs including capital costs, operation and maintenance costs, insurance, ad valorem, environmental compliance costs, construction cost, and taxes. Various worksheets are included to help conduct repetitive calculations, such as Yearly Cost, which calculates costs over numerous years, and Print Tables, which calculates costs over multiple technologies at once. The Cost of Generation Model has two additional features not commonly found in other cost of generation models: *screening curve* and *sensitivity curves*. The screening curve function shows the relationship between levelized cost and capacity

factor. The sensitivity curves function with the ability to show the change in levelized cost as a function of individual input assumptions.

Improvements to the Model

The Cost of Generation Model used for the *2009 Integrated Energy Policy Report* was an improvement over the original Cost of Generation Model used for the *2007 Integrated Energy Policy Report* in five ways:

- Provided deterministic high and low levelized cost of electricity.
- Allowed costs, most importantly instant costs, to vary in real dollars over time.
- Allowed cash-flow accounting for merchant plants, which reduced the calculated levelized cost for renewables by as much as 30 percent.
- Estimated transmission transaction costs and transmission losses to the load center.
- Improved estimates of tax benefits by allowing the developer to either take the full benefit in the first year or to carry-forward taxes to the following years.
- Provided a “print tables” function to compile the summary of levelized cost of electricity data.

The Cost of Generation Model used for *the 2013 Integrated Energy Policy Report* improves the current effort by:

- Providing high and low probabilistic levelized costs of electricity working in conjunction with the Lumina’s Analytica Model.
- Providing “tornado diagrams” to quantify the impact of cost components on the mid case levelized cost of electricity.
- Better assessing the effect of emission reduction credits on costs.
- Adding greenhouse gas costs as a part of the levelized cost of electricity.
- Deleting transmission cost (service and losses) costs to the load center as a component of levelized cost of electricity—determined to not be applicable.
- Better assessing the transmission costs and losses to the point of interconnection.
- More carefully characterizing the impact and trend in tax incentives on levelized cost of electricity.
- Provideing a “yearly costs” function to compile cost summaries for instant, installed, and levelized cost of electricity for user defined ranges of years.

CHAPTER 1:

Introduction

The Cost of Generation Model (COG Model) is an Excel spreadsheet model that calculates levelized cost of energy (LCOE) for utility-scale electric generating technologies (power plants 20 megawatts [MW] in size or greater that are used to meet the demand served by California's electric grid). These LCOEs provide a mechanism to compare the cost of one power plant to another—the object being that the power plant with the lower levelized cost is more economical from the developer's standpoint. The LCOE estimates and/or the supporting data assumptions are important in all generation and transmission studies involving costs. These LCOEs and supporting data are used not only within the California Energy Commission, but by other entities such as the California Independent System Operator (California ISO), the California Public Utilities Commission (CPUC), the Board of Equalization (BOE), the Western Electricity Coordinating Council (WECC), as well as various consultants and educational institutions.

Care must be taken not to misuse these levelized costs. The COG Model produces **mid case** levelized costs, essentially average costs, for various technologies but recognizes that the actual costs vary widely. In deference to that concern, the COG Model produces high and low case estimates to capture the uncertainty of the levelized costs. Relying on **mid case** levelized costs is simplistic and can lead to poor planning decisions.

Furthermore, these levelized cost estimates do not include an evaluation of how each unit may function in the system or how the system may affect the operation of the power plant, which are critical for a system costs study. Such estimates require a time emulation model, such as a production cost or market model. Finally, these cost estimates do not address environmental, system diversity, or risk factors, which are vital planning aspects of all resource development.

The Energy Commission's COG Model was first used in the *2003 Integrated Energy Policy Report (2003 IEPR)* and at that time consisted of 25 spreadsheets. For the *2007 IEPR*, the 25 spreadsheets were condensed into a single model that was transparent and user-friendly. More important, the COG Model was made more accurate through improved algorithms and improved data based on actual survey data. The *2009 IEPR* version improved the process by providing average, high, and low cost scenarios. It also provided a more accurate assessment of the trends in costs over time, most important, instant costs. It improved the modeling algorithms to apply both cash flow for merchant modeling and revenue requirement accounting for investor-owned utility (IOU) and publicly owned utility (POU) modeling. It also included estimates of transmission costs, and improved tax benefit emulation.

The Energy Commission's *2013 IEPR* COG Model is improved in several ways, the most important of which is the implementation of probabilistic analysis in developing the high

and low levelized costs. These are probabilistic ranges of LCOE, generated using the Analytica Cost of Generation Analysis Tool (ACAT)¹, a model developed using Lumina's Analytica probabilistic software² in conjunction with the Energy Commission's deterministic COG Model.

It also has an improved assessment of emission reduction credits (ERCs) and the addition of greenhouse gas emission costs. In addition, it has improved the ability to summarize instant, installed, and levelized costs over time, which allows emulation of such as detailed assessments as the effect of tax benefits over time.

The COG Model continues to have the analytical functions of screening curves and sensitivity curves that allow users to evaluate the effect of the various operational and cost factors on levelized costs. It includes the "print tables" function, which simplifies single year summaries of levelized costs and supporting assumptions, and compares these values. It also has a "yearly costs" mechanism that automates the calculation of yearly instant, installed, and levelized cost for the mid, high and low cost cases.

The documentation within the COG Model is sufficient to run the tool. For a complete understanding of the COG Model and the design subtleties, it is also necessary to understand this user's guide. The COG Model and the draft assumptions were the subject of a March 7, 2013, workshop. Several comments were received and as appropriate have been incorporated into the COG Model.

Overview of the Cost of Generation Model

The COG Model calculates total levelized costs, which are the sum of the following fixed and variable cost components:

Fixed Costs:

- Capital and Financing—total cost of construction, including transmission interconnection and financing the plant.
- Insurance—cost of insuring the power plant.
- Ad Valorem—property taxes.
- Fixed Operation and Maintenance—staffing and other costs that are independent of operating hours.
- Corporate Taxes—state and federal taxes.

Variable Costs:

- Fuel Cost—cost of the fuel used.
- Variable Operation and Maintenance—operation and maintenance costs that are a function of the number of operating hours.

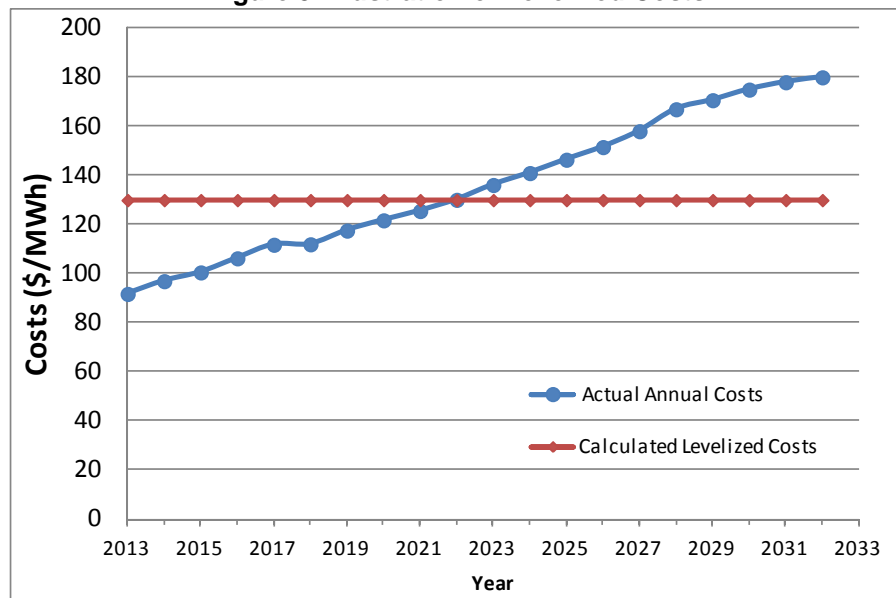
¹ See Analytica COG Analysis Tool (ACAT) User Guide 1.0. Lumina Decision Systems, January 2013.

² For details on Analytica, see <http://www.lumina.com/>.

Insurance, ad valorem, and the operation and maintenance costs are essentially estimating the first-year cost and then escalating that cost over the life of the study to account for nominal and real inflation. Annual fuel costs (dollar per megawatt-hour [\$/MWh]) are a function of the fuel use, cost of the fuel cost price forecast (dollars per million British thermal units), and any capacity and heat rate degradation that might occur.

Using dozens of cost, financial, and tax assumptions, the COG Model calculates the costs for a technology on an annual basis, finds a present value of those annual costs, and then calculates the LCOE. **Figure 3** illustrates the relationship between the actual annual costs and calculated LCOE. This relationship is defined by the net present value of the LCOEs being equal to the net present value of the current and future annual costs. This annualized cost value (LCOE) allows for the comparison of one technology against the other, whereas the differing annual costs are not easily compared.

Figure 3: Illustration of Levelized Costs



Source: Energy Commission

All these estimates are a function of who the developer is: merchant, IOU, or POU. The financing costs are particularly different for the three developers. POU's finance solely through debt, whereas merchant and IOUs raise money through debt and equity (stocks). Each developer type makes debt and equity payments in different ways. Debt payments are constant for merchant plants but a function of book value for IOUs. Equity payments for merchant plants are calculated based on cash-flow accounting but based on revenue requirement accounting for IOUs.

These results are presented as a cost per unit of generation over the period under investigation. This calculation is done by dividing the costs by the sum of all the expected generation over the time horizon being analyzed. The most common presentation of levelized costs is in \$/MWh or cents/kWh.

LCOE is generated by the COG Model using multiple algorithms. The levelized cost formula used in this model first sums the net present value of the cost components and then computes the annual payment with interest (or discount rate, r) required to pay off that present value over the specified period T. The formula is as follows:

$$\text{LCOE} = \sum_{t=1}^T \frac{\text{Cost}_t}{(1+r)^t} * \frac{r * (1+r)^T}{((1+r)^T - 1)}$$

Capital financing and corporate taxes are more complicated in that the amount of financing cannot be estimated without knowing the taxes, and the taxes cannot be known until amount of financing is known. This interdependence requires simultaneous equations. These equations are built into the cash-flow income statement, which is used to calculate the LCOE for IOUs and merchant developers. Since POU's do not have taxes, the LCOE is determined using the revenue requirement income sheet. Further details about both these methods are contained in Chapter 4.

The COG Model has several features. The COG Model calculates levelized costs by component in \$/MWh and dollars per kilowatt-year (\$/kW-yr). The tool includes the ability to model all physical features, including power plant and transmission interconnection losses, capacity and heat rate degradation, and emission factors. The costs include capital cost, operation and maintenance costs, insurance, ad valorem, environmental compliance costs, construction cost, and taxes. The COG Model has two additional features not commonly found in other cost of generation models: screening curves and sensitivity curves.

Organization of User's Guide

The user's guide provides a description of the COG Model, a summary of the features of the model, a detailed description of the algorithms, and instructions on how to use the COG Model.

Chapter 1 describes the purpose of the user's guide and provides a brief history of the COG Model and a brief description of the COG Model.

Chapter 2 provides an overview of the COG Model. It describes the structure of the Cost of Generation Model and related various worksheets, the most important of which are:

- Input-output worksheet, which is used input selection and output results.
- Assumptions worksheets that provide the technology-specific data for the data worksheets:
 - Plant type assumptions worksheets that summarize the mid (average), high, and low plant-specific performance and cost data for each of the technologies.
 - Financial assumptions worksheet that provides the capital structure, and cost of debt and equity assumptions.

- General assumptions worksheet that provides the nonpower plant-specific assumption, such as inflation rates, tax rates, and average rates of nominal and real inflation.
- Data worksheets that compile and process the technology specific data:
 - Physical data worksheet that summarizes key plant data.
 - Financial data worksheet that collects the financial and tax data.
 - Construction cost worksheet that calculates the instant and installed cost.
 - Operation and maintenance (O&M) worksheet that calculates the fixed and variable operation and maintenance costs.
- Income statements worksheets (income cash-flow and income revenue requirement worksheets) that use the above data sheets to calculate levelized cost.
- Special function worksheets that are detailed in Chapter 3.

Chapter 3 instructs the user on how to use the COG Model:

- How to select the preset technology assumptions.
- How to create, save, and recall scenarios.
- How to read and interpret the results.
- How to read and interpret summary tables.
- How to use the special features of the COG Model.

This chapter also details the special function worksheets that are useful in interpreting and understanding the output data. They are:

- Annual costs chart.
- Screening curves.
- Sensitivity curves.
- Print tables.
- Yearly costs.

Chapter 4 provides a detailed description of the more complex worksheets:

- Input-output worksheet and its data summary tables.
- Physical data worksheet.
- Financial data worksheet.
- Construction cost worksheet.
- O&M costs worksheet.
- Income statement worksheets and related algorithms.
- Overhaul worksheet and the related newly developed algorithms for estimating the costs of overhauls.

Appendix A provides a complete list of related definitions.

Appendix B is a summary of federal tax incentives.

Attachment C is a source reference for the heat rate and capacity degradation calculations in Chapter 4.

Attachment D provides a description of asset rental prices.

CHAPTER 2: Cost of Generation Model Overview

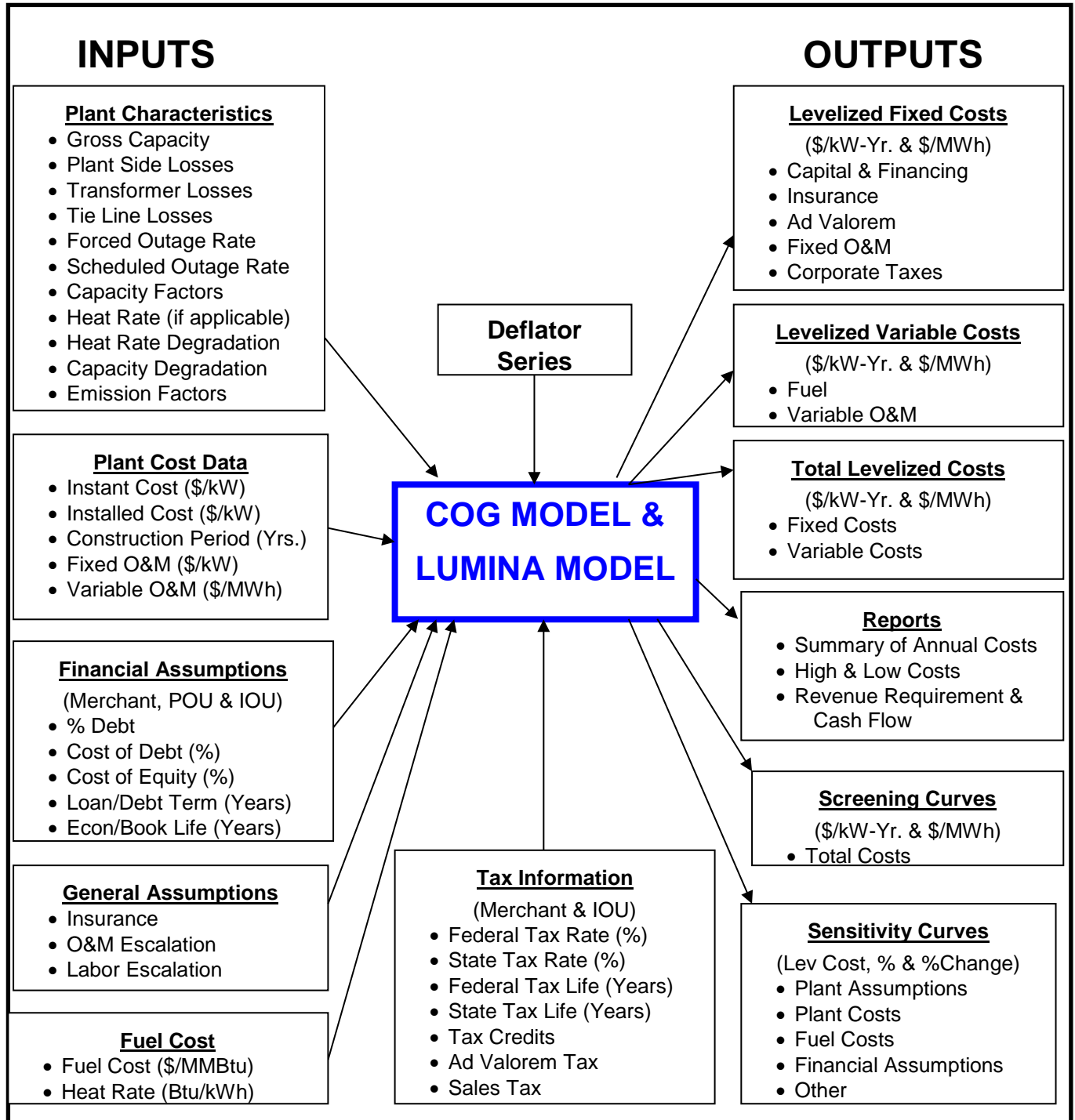
A simplified flow chart of the COG and Lumina Models is shown in **Figure 4**. Using the inputs on the left side of the flow chart, which are described later in this chapter, the COG Model can produce the outputs shown on the right side of the flow chart. The top set of output boxes on the right show the key levelized cost outputs:

- Levelized fixed costs
- Levelized variable costs
- Total levelized costs (fixed + variable)

The Energy Commission's COG Model is more sophisticated than most traditional models since it can create other outputs not commonly provided in a model of this type:

- It provides levelized costs both in \$/kW-Yr and \$/MWh—and does this for mid, high and low costs.
- It provides these levelized costs as both deterministic and probabilistic values.
- It presently has 19 technologies but can be expanded to accommodate an almost unlimited number of technologies.
- It can store and recall user-defined perturbations of the existing technologies.
- It provides annual costs both in tabular and graphical format.
- It provides a screening curve function that shows the relationship between levelized cost and capacity factor.
- It provides a sensitivity curves function with the ability to show the change in levelized cost as a function of input assumptions.
- It provides a yearly costs function that calculates and graphs instant, installed, and levelized costs by costs case and by developer over selected periods.

Figure 4: Flow Chart for Cost of Generation Model



Source: Energy Commission

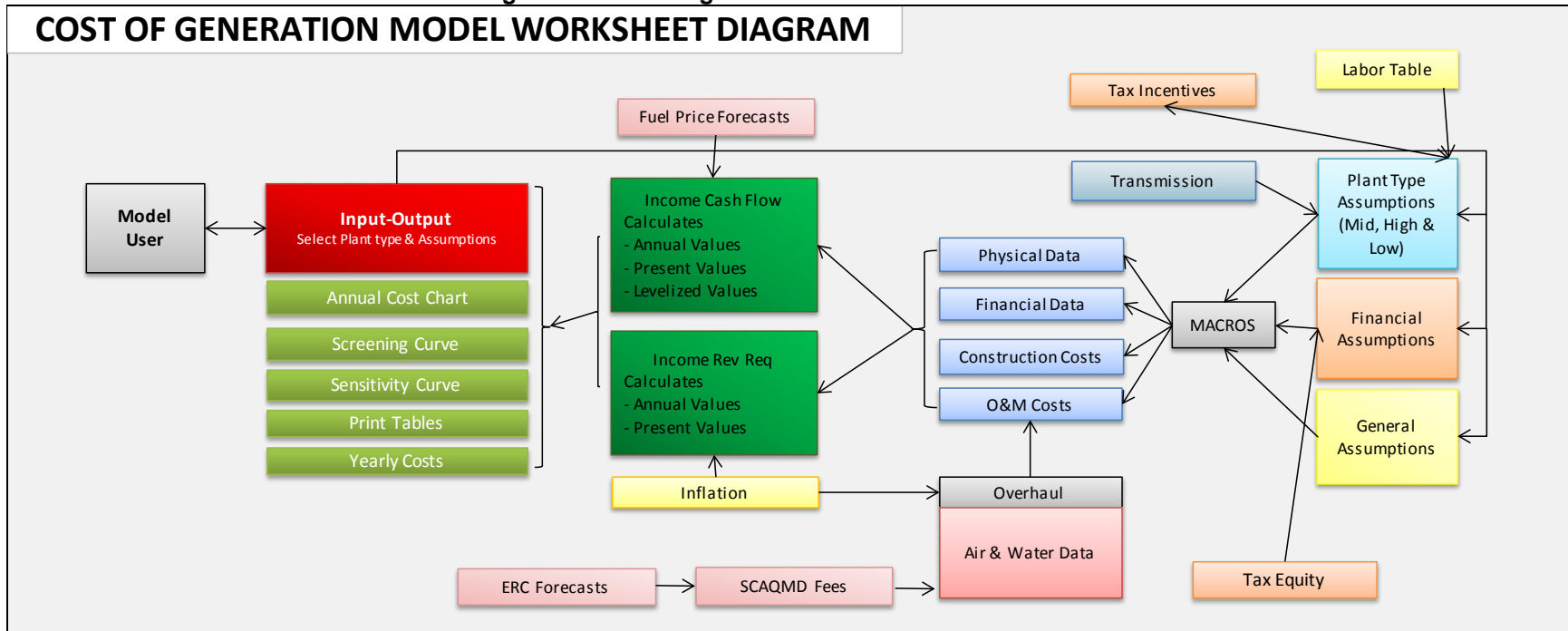
This workbook consists of the worksheets itemized in **Table 1**. The relationship of these worksheets is illustrated in the block diagram of **Figure 5**.

Table 1: Cost of Generation Model Worksheets

| | |
|-------------------------------|--|
| Instructions | General Instructions & Model Description. |
| Input-Output | User selects Assumptions - Levelized Costs are reported along with some key data values. |
| Annual Cost Chart | Reports annual fixed, variable and total O&M costs for selected scenario as well as the NPV for each cost stream |
| Screening Curve | Contains a GUI and macro that graphs the levelized cost as a function of capacity factor for any of the plant technologies. (not working) |
| Sensitivity Curve | Contains a GUI and macro that graph the levelized cost as a function of a percent change in various base values so as to examine the sensitivity of the output to the specified variables. (not working) |
| Print Tables | Presents and compares costs for all technologies and developers for up to two scenarios |
| Yearly Costs | User selects technologies, developers and cost cases and annual costs are presented for each selection |
| Changes | Tracks Model modifications using version numbers |
| Physical Data | plant physical data is summarized - User can override data for unique scenarios. |
| Financial Data | Financial & Tax Data are summarized - User can override data for unique scenarios |
| Construction Costs | Construction Costs are calculated in base year dollars |
| O&M Costs | O&M Costs are calculated in base year dollars |
| Income Cash -Flow | Calculates Annual Costs and Levelizes those Costs – Using Cash-Flow accounting |
| Income Rev Req | Calculates Annual Costs and Levelizes those Costs – Using Revenue Requirement accounting |
| Inflation | Calculates Historical & Forward Inflation Rates based on GDP Price Deflator Series - Used by Income Worksheets |
| Financial Assumptions | Data Assumptions summary of all Financial Data. |
| Tax Equity | Equity return calculations for renewables (wind and non-wind) |
| Tax Incentives | Presents information on tax incentives by technology |
| Transmission | Reports transmission line costs and losses |
| Fuel Price Forecasts | Fuel Price Forecast - Used by the Income Worksheets. |
| Air & Water Data | Regional Air Emissions & Water Costs - Used by Data 2 Worksheet. |
| ERC Forecasts | General Assumptions summary such as Inflation Rates & Tax Rates. |
| SCAQMD Fees | Presents SCAQMD Rule 1304.1 In-lieu ERC Fees |
| Plant Type Assumptions | Summary of Data Assumptions summary for each Plant Type. |
| PTA - Mid | Mid Plant Type Assumptions |
| PTA - High | High Plant Type Assumptions Presents forecast of ERC costs for various pollutants and regions |
| PTA - Low | Low Plant Type Assumptions |
| General Assumptions | General Assumptions summary such as Inflation Rates & Tax Rates. |
| Labor Table | Calculates the Labor Cost components. |
| Overhaul Calcs | Calculates Overhaul & Equipment Replacement Costs |

Source: Energy Commission

Figure 5: Block Diagram for Cost of Generation Model



Source: Energy Commission

One way to better understand the COG Model is to visualize the income statement worksheets (cash-flow and revenue requirement) as models, visualize the input-output worksheet as the control module that also summarizes the results, and think of the remaining worksheets as data inputs. The physical data, financial data, construction, and O&M worksheets can be considered to be the data set (broken into four parts only for convenience) that gathers the technology-specific data from the warehouse of assumptions in other auxiliary assumptions worksheets. The following is an overview of the key worksheets. In Chapter 4 these worksheets are discussed in more detail to explain the subtler aspects.

Input-Output Worksheet

This worksheet is the main interface of the COG Model. It has three key sections: an input selection section panel to select a technology and related characteristics, an output results section panel the reports the levelized costs in component detail, and a data assumptions summary. This summary is where the technology is selected and the levelized costs are reported.

Assumptions Worksheets

Most of the data used in the COG Model is compiled into the following three worksheets, which are color-coded, as shown in **Table 2**. These worksheets store the data from which the other data sheets draw from the data and computations.

Table 2: Color Coding for Assumptions Worksheets

| Indicates Data Type |
|------------------------|
| Plant Type Assumptions |
| Financial Assumptions |
| General Assumptions |

Source: Energy Commission

The user may override any of the data in the physical data, financial data, construction costs, or O&M costs worksheets for any values that are shaded in turquoise, tan, or yellow, as delineated in **Table 2**.

Plant Type Assumptions

The plant type assumptions (PTA) worksheet stores all the power plant-specific data, such as plant size, plant performance characteristics such as heat rates, construction costs, O&M costs, environmental costs, and interconnection costs—some of which are calculated and linked from the respective worksheets. There are more than 200 of these items categorized in areas such as instant costs, O&M costs, heat rates, degradation rates, and taxes.

The COG Model has three PTA worksheets: PTA-mid, PTA-hi, and PTA-lo. Depending on the cost scenario selected in the input selection panel, the corresponding PTA sheet transfers its data to the main plant type assumptions worksheet. The PTA-mid, -hi, and -lo worksheets in turn rely on costs from three additional worksheets: labor table, tax incentives, and transmission. The labor table worksheet lists the labor costs that are used in the PTAs sheet to calculate the fixed O&M labor costs. The tax incentives worksheet lists values for the tax incentives that are used in the PTA sheets. The transmission worksheet calculates the transmission interconnection costs that are used in the PTA sheets.

Financial Assumptions

The financial assumptions worksheet stores the capital structure and cost of capital data for the three main categories of ownership: merchant, IOUs, and POUs. The worksheet provides the relative percentages of equity as opposed to long-term debt, as well as the cost of capital for these two basic financing mechanisms. It also provides data on eligibility for tax credits. It shows the financial assumptions for average, high, and low cost scenarios.

General Assumptions

There is a multitude of assumptions that are common to all power plant types, such as inflation rates, tax rates, tax credits, station service, transformer losses, and transmission losses. Based on the user selections in the input-output worksheet, the relevant data in these assumptions worksheets are automatically sent to the data worksheets, which are described in the following section.

Data Worksheets

This is where the macro places the data selected from the assumptions worksheets (PTA, financial, and general), and basic calculations are made to prepare data for the income statement worksheets (income cash flow and income revenue requirements). The four data worksheets (physical, financial, construction, and O&M) can be envisioned as four subsections of the dataset to be used in the income statements. These are separated solely to keep the worksheets to a reasonable size. These worksheets also provide the opportunity for the user to modify or replace the data that came from the assumptions worksheets, to allow the user to produce scenarios. Care should be taken to modify only those areas that are shaded in color.

Physical Data

The physical data worksheet summarizes key plant capacity size and energy data, the effect of losses and capacity degradation, fuel use (such as heat rate and generation), and operational performance data (such as capacity factor, forced outage rate, and scheduled outage factor).

Financial Data

The financial data worksheet collects the financial and tax data necessary to the income statement worksheets.

Construction Costs

The construction costs worksheet calculates the instant and installed costs of the applicable technology. It calculates the instant cost by taking the PTA instant cost and adding the ancillary costs such as land costs, permitting costs, and ERCs. It converts the instant cost to installed cost, allowing for the construction period, and then escalates those costs to the selected start -year. This construction costs worksheet relies on the air and water data, ERC forecasts, and transmission worksheets.

Air and Water Data

The air and water data worksheet summarizes the ERC costs that in turn rely on the ERC forecast worksheet.

ERC Forecasts

The ERC forecasts worksheet calculates the annual ERC values by air district.

Transmission

The transmission worksheet calculates the interconnection cost based on interconnection voltage and tie line length. The data from this worksheet populate the PTA worksheets.

O&M Costs

The O&M worksheet makes separate calculations for the fixed and variable O&M. It can receive the respective costs as single values or build up the costs component by component, depending upon the values provided in the PTA sheets. This worksheet sometimes relies on costs from the following worksheets, depending on whether the O&M data are calculated by components or simply entered as single values for fixed and variable O&M.

Overhaul Calculations

This model circumvents this complex calculation. Instead, it is collected and inputted in the model as a single override value on the O&M worksheet. In the case of gas-fired units, the fixed O&M override value is calculated on the PTA worksheets. O&M detail may be added using the overhaul calculations worksheet, if the user desires.

These costs are calculated outside the O&M costs worksheet since they are nonperiodic overhaul costs that require special treatment to derive the necessary base year costs needed by the O&M costs worksheet. These are complex calculations that are explained in the overhaul calculations worksheet detail. All the data in these worksheets are for base year dollars. These costs are used by the income statement worksheet to calculate the yearly values and account for inflation.

Fuel Price Forecasts

The fuel price forecasts worksheet provides the fuel prices (nominal 2011 \$/MMBtu) to the income statement worksheets for mid, high, and low cost cases. For the mid cost case, the natural gas price forecast is provided by utility service area, as well as a California average value. For the high and low forecasts, it provides only a mid natural gas price forecast. It

also has three cost scenarios for biomass. This worksheet allows storage of different forecasts if needed to conduct various scenario studies. These forecasts should be updated regularly to represent the most recent Energy Commission forecasts—or other applicable forecast, depending on the nature of the study. The inflation factors used in this worksheet come from and must absolutely be consistent with the inflation worksheet.

Inflation

The inflation worksheet provides inflation factors used by the income statement, overhaul, and data worksheets needed to inflate the various capital and O&M costs. This worksheet calculates two inflation values to simplify the income statement calculations: a historical inflation rate, used for the period from the base year to the start year, and a forward inflation rate, used for the period from the start year to the end of the study.

Income Statement Worksheets

For merchant plants, the income statement worksheet is an income cash-flow worksheet. For IOUs and POUs, the income statement is an income revenue requirement worksheet. For each of the following categories, this worksheet takes the data from the above data sources and develops the yearly cost values, then the present values, and finally the necessary levelized costs. The details of this worksheet are provided in the Income Statement details section.

Fixed Costs:

- Capital and Financing—total cost of equipment, construction, and financing the plant
- Insurance—cost of insuring the power plant over its lifetime operation
- Ad Valorem—property taxes
- Fixed O&M—staffing and other costs that are independent of the operating hours
- Taxes—federal and state taxes inclusive of all tax benefits

Variable Costs:

- Fuel Cost—cost of the fuel used
- Variable O&M—O&M costs that are a function of operating hours.
- Greenhouse Gas Emission Costs

Special Functions Worksheets

These worksheets provide special functions that ease interpreting and making use of data within the COG Model. These are detailed in Chapter 3. They are:

- Annual costs chart worksheet that provides summary tables of annual data that promote understanding the model data.
- Screening curves worksheet that provides a screening curve function that allows study of the effect of capacity factor on LCOE. It works only when a single technology is selected.
- Sensitivity curves worksheet that provides a sensitivity curve function allowing the study of the effect of the various parameters on LCOE, not just capacity factor.
- Print tables worksheet that provides summary tables of LCOE, plant cost data, and plant parameters.
- Yearly costs worksheet that provides a multiyear summary data of instant costs, installed costs, and/or LCOE costs for the selected technologies. Costs can be produced as a function of any developer in either real or nominal dollars.

CHAPTER 3:

Using the Cost of Generation Model

This chapter describes the procedure for using preset data and user-specified data in the COG Model. Instruction is provided for selecting assumptions for the technologies in the COG Model, for adding new technologies, revising assumptions, and saving new entries as scenarios to be recalled later.

Admonishment to All Cost of Generation Model Users

Before any run, fuel price forecasts and inflation worksheets should be reviewed for current information—or at least for applicability. The data in the other worksheets must also be reviewed periodically for updates.

Opening the Cost of Generation Model

The COG Model will not run correctly unless Excel® 2007 or higher is used and the macros are activated. For Excel 2007 or later versions, the following will appear above the COG Model worksheet: “**Security Warning:** Some active content has been disabled,” followed by an “Options” box. Click on the box and a window with two options will open. Select “Enable this content” and click “Okay,” and the window will close, activating the macros. If the macros are not activated, the COG Model may appear to be working but will not function properly.

Using the Cost of Generation Model With Its Preset Data

The central interface of the COG Model is the input-output worksheet, that is used to select the technology and its assumptions, and read the results. The procedure consists of selecting inputs and reading the results—and verifying the assumptions as applicable to the study.

Selecting Inputs

Select the input-output worksheet. Look for the section of this worksheet (see **Figure 6**) that illustrates a combined cycle technology with duct firing. Using the drop-down menus, select each assumption as follows:


- Step 1: Select developer and financing—this provides the appropriate financing assumptions. Select merchant, IOU, or POU depending on which entity is financing the technology. Do this in conjunction with the type of technology (fossil [gas-fired] or renewable).
- Step 2: Select start-year—the year the technology is to go online and generate power.
- Step 3: Select technology—select the appropriate technology from the drop-down window.
- Step 4: Select a tax treatment option from the following:

- Tax Equity Financing: The developer takes full advantage of the tax incentives.
- Tax Minimum Equals Zero: The developer takes partial advantage of tax incentives.
- Recovered Through Federal Tax Grant: A option from the 2009 IEPR that is no longer applicable and is provided for reference only.

Steps 5 through 7 are for gas-fired technologies only and should be ignored for renewable technology studies.

- Step 5: Select carbon price—select mid case, high case, or low case as appropriate to the study. The 2013 IEPR COG study used mid case only.
- Step 6: Select natural gas price—select mid case, high case, or low case as appropriate to the study.
- Step 7: Select plant site region—this is used primarily to set regional ERC values.

Figure 6: Input Selection Table

| <u>INPUT SELECTION</u> | |
|--|--|
| Step 1: Select Developer and Financing | Merchant Fossil |
| Step 2: Select Start-Year | 2013 |
| Step 3: Select Technology | Combined Cycle - 2 CTs No Duct Firing 500 MW |
| Step 4: Select Tax Loss Treatment | Tax Minimum Equals Zero |
| <u>FOR GAS-FIRED UNITS ONLY</u> | |
| Step 5: Select Carbon Price | Carbon Price Mid |
| Step 6: Select Natural Gas Price | CA Average |
| Step 7: Select Plant Site Region | CA - Avg. |
| Step 8: Click the Execute Button |  |

Source: Energy Commission.

Reading the Results

After inputting data, the results can be found in the adjacent cost summary table, as shown in **Table 3**. This table shows the LCOE and mid case, high case, and low case cost components—noting that the high case and low case levelized costs are deterministic values based on the coincidental all high and all low assumptions, respectively.

Table 3: Output Summary Table

| Combined Cycle - 2 CTs No Duct Firing 500 MW | | | | | | |
|---|-----------------|-----------------|------------------|-----------------|-----------------|----------------|
| Merchant Fossil | Mid Case | | High Case | | Low Case | |
| Start Year = 2013 (2013 Dollars) | \$/kW-Yr | \$/MWh | \$/kW-Yr | \$/MWh | \$/kW-Yr | \$/MWh |
| Capital & Financing - Construction | \$114.37 | \$24.16 | \$190.21 | \$57.88 | \$63.93 | \$10.67 |
| Insurance | \$7.72 | \$1.63 | \$8.76 | \$2.67 | \$6.09 | \$1.02 |
| Ad Valorem Costs | \$11.19 | \$2.36 | \$11.91 | \$3.62 | \$8.54 | \$1.43 |
| Fixed O&M | \$43.23 | \$9.13 | \$94.65 | \$28.80 | \$17.69 | \$2.95 |
| Corporate Taxes (w/Credits) | \$37.77 | \$7.98 | \$71.90 | \$21.88 | \$8.81 | \$1.47 |
| Fixed Costs | \$214.28 | \$45.27 | \$377.43 | \$114.85 | \$105.06 | \$17.54 |
| Fuel & GHG Emissions Costs | \$333.39 | \$70.44 | \$283.59 | \$86.29 | \$267.61 | \$44.69 |
| Variable O&M | \$3.75 | \$0.79 | \$7.49 | \$2.28 | \$1.50 | \$0.25 |
| Variable Costs | \$337.14 | \$71.23 | \$291.08 | \$88.57 | \$269.10 | \$44.94 |
| Total Levelized Costs At Interconnection Point | \$551.42 | \$116.51 | \$668.51 | \$203.42 | \$374.16 | \$62.48 |

Source: Energy Commission.

Confirming Assumptions

The inputs in **Figure 6** are categorical. It is important to examine the input assumptions located just below the output summary table (see **Table 4**). The model is populated with the best data available. However, this data should be reviewed to assure that it is applicable to the study.

Table 4: Summary of Data Assumptions
DATA ASSUMPTIONS ASSOCIATED WITH YOUR INPUT SELECTION

| Cost Case Assumptions | Mid Case | | High Case | | Low Case | |
|---|----------------------|------------------------|----------------------|------------------------|----------------------|------------------------|
| Capital & Operating Costs | Base Yr 2011 | Start Yr 2013 | Base Yr 2011 | Start Yr 2013 | Base Yr 2011 | Start Yr 2013 |
| Instant Cost (\$/kW) | \$956 | \$1,000 | \$1,093 | \$1,144 | \$779 | \$816 |
| Installed Cost (\$/kW) | \$1,040 | \$1,088 | \$1,257 | \$1,316 | \$805 | \$843 |
| Ratio of Installed Cost to Instant Cost | | 1.088 | | 1.150 | | 1.033 |
| Ratio of Installed Cost to Component Cost | | 1.2365 | | 1.467 | | 1.1519 |
| Fixed O&M Cost (\$/kW-Yr) | \$32.69 | \$34.56 | \$77.96 | \$82.42 | \$13.04 | \$13.79 |
| Variable O&M Cost (\$/MWh) | \$0.58 | \$0.61 | \$1.79 | \$1.89 | \$0.18 | \$0.19 |
| Total O&M (\$/MWh) | \$7.13 | \$7.54 | \$24.04 | \$25.42 | \$2.28 | \$2.41 |
| Total O&M (\$/kW-Yr) | \$35.59 | \$37.62 | \$84.23 | \$89.06 | \$14.16 | \$14.97 |
| Insurance (\$/kW-Yr) | \$6.24 | \$6.53 | \$7.54 | \$7.89 | \$4.83 | \$5.06 |
| Ad Valorem (\$/kW-Yr) | \$11.30 | \$11.83 | \$13.39 | \$14.01 | \$8.75 | \$9.16 |
| Operational Performance | Factor | Hours | Factor | Hours | Factor | Hours |
| Scheduled Outage Factor (SOF) | 6.02% | 527.4 | 6.02% | 527.4 | 6.02% | 527.4 |
| Forced Outage Rate (FOR) | 2.24% | 114.4 | 2.24% | 80.3 | 2.24% | 142.5 |
| Operational (Service) Hours Per Year | | 4,993.2 | | 3,504.0 | | 6,219.6 |
| Equivalent Availability Factor | 91.87% | | 91.87% | | 91.87% | |
| Capacity Factor | 57.00% | | 40.00% | | 71.00% | |
| Fuel Use Summary | 2013 | Levelized | 2013 | Levelized | 2013 | Levelized |
| Average Heat Rate (Btu/kWh) | 7,250 | 7,383 | 7,480 | 7,595 | 7,030 | 7,117 |
| Fuel Use (MMBtu) | 18,100,350 | 18,100,350 | 13,104,960 | 13,104,960 | 21,861,894 | 21,861,894 |
| Fuel Price (\$/MMBtu) | \$4.56 | \$7.11 | \$6.67 | \$9.32 | \$2.79 | \$3.83 |
| Financial Information | Cap Structure | Cost of Capital | Cap Structure | Cost of Capital | Cap Structure | Cost of Capital |
| Weighted Avg. Equity | | 13.25% | | 15.00% | | 10.41% |
| Equity | 33.0% | 13.25% | 60.0% | 15.00% | 20.0% | 10.41% |
| Tax Equity | 0.0% | 0.00% | 0.0% | 0.00% | 0.0% | 0.00% |
| Debt Financed: | 67.0% | 4.52% | 40.0% | 6.63% | 80.0% | 4.64% |
| Discount Rate (WACC) | 6.17% | 4.53% | 10.57% | 8.84% | 4.28% | 2.68% |
| Inflation Rate From Base Yr. To Start Yr. | 2.31% | | 2.31% | | 2.31% | |
| Inflation Rate From Start Year Forward | 1.56% | | 1.59% | | 1.56% | |
| Loan/Debt Term (Years) | 10 | | 7 | | 20 | |
| Equipment Life (Years): | 30 | 12/31/2042 | 20 | 12/31/2032 | 30 | 12/31/2042 |
| Economic/Book Life (Years) | 30 | | 20 | | 30 | |
| Federal Tax Life (Years) | 20 | | 20 | | 20 | |
| State Tax Life (Years) | 20 | | 20 | | 20 | |
| Capacity and Energy | Effective MW | Energy GWh | Effective MW | Energy GWh | Effective MW | Energy GWh |
| Gross (Dependable) | 500.0 | 2451.7 | 500.0 | 1725.5 | 500.0 | 3071.7 |
| Net Capacity - Plant Side | 485.5 | 2380.6 | 480.0 | 1656.5 | 490.0 | 3010.3 |
| Net Capacity - Transmission Side | 483.1 | 2368.7 | 477.6 | 1648.2 | 487.6 | 2995.2 |
| At Interconnection Point | 482.6 | 2366.5 | 476.1 | 1643.1 | 487.4 | 2994.3 |

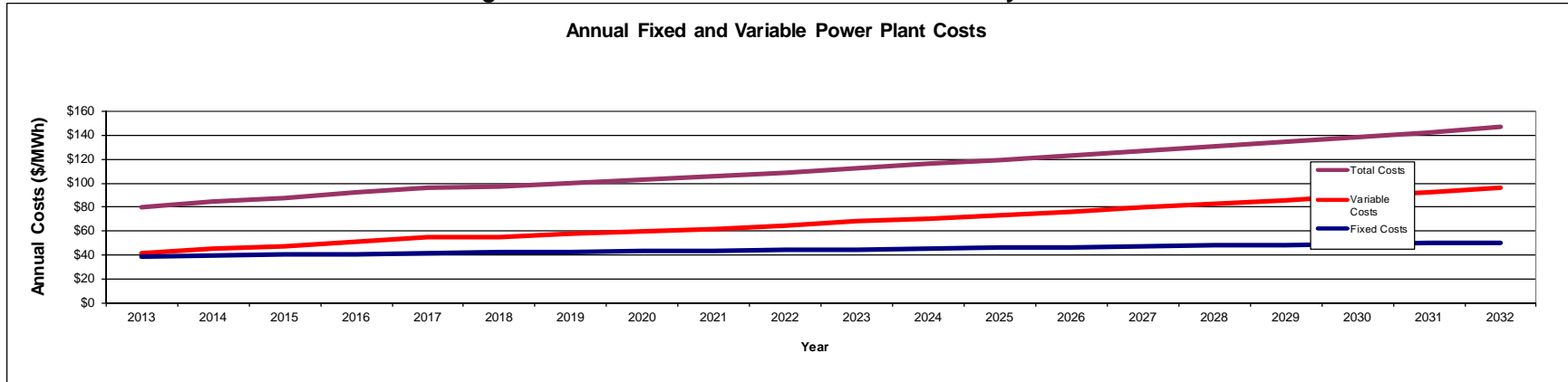
| Merchant Fossil | Mid Case | | High Case | | Low Case | |
|--|-----------------|--|------------------|--|-----------------|--|
| Debt Service Coverage Ratios - Average | <u>1.52</u> | | <u>2.61</u> | | <u>1.37</u> | |
| Debt Service Coverage Ratios - Minimum | <u>1.42</u> | | <u>2.48</u> | | <u>1.27</u> | |

Source: Energy Commission.

Annual Cost Summary

A special convenience of the COG Model is its upfront summary of annual costs. Although levelized cost is the most commonly used output of the COG Model, many studies rely on actual costs. These costs are summarized in the annual cost worksheet to promote (or make easier) these studies. **Figure 7** shows the actual annual costs that were used to calculate the present values and then the levelized costs, in both graphical and numerical format. **Table 5** shows the corresponding asset rental prices, which is not used otherwise in the COG Model. The concept is not commonly used; further explanation is available in Attachment B.

Figure 7: Annual Costs—Merchant Combined Cycle Plant



| | Levelized | NPV | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|----------------|-----------|---------|------|------|------|------|------|------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| Fixed Costs | \$45 | \$612 | \$39 | \$40 | \$40 | \$41 | \$42 | \$42 | \$43 | \$43 | \$44 | \$44 | \$45 | \$46 | \$46 | \$47 | \$47 | \$48 | \$49 | \$49 | \$50 | \$51 |
| Variable Costs | \$71 | \$963 | \$42 | \$45 | \$47 | \$51 | \$55 | \$55 | \$58 | \$60 | \$62 | \$64 | \$68 | \$71 | \$73 | \$76 | \$80 | \$83 | \$86 | \$89 | \$93 | \$96 |
| Total Costs | \$117 | \$1,575 | \$80 | \$85 | \$87 | \$92 | \$97 | \$97 | \$100 | \$103 | \$106 | \$109 | \$113 | \$116 | \$120 | \$123 | \$127 | \$131 | \$134 | \$139 | \$143 | \$147 |

Source: Energy Commission.

Table 5: Annual Costs Based on Asset Rental Price

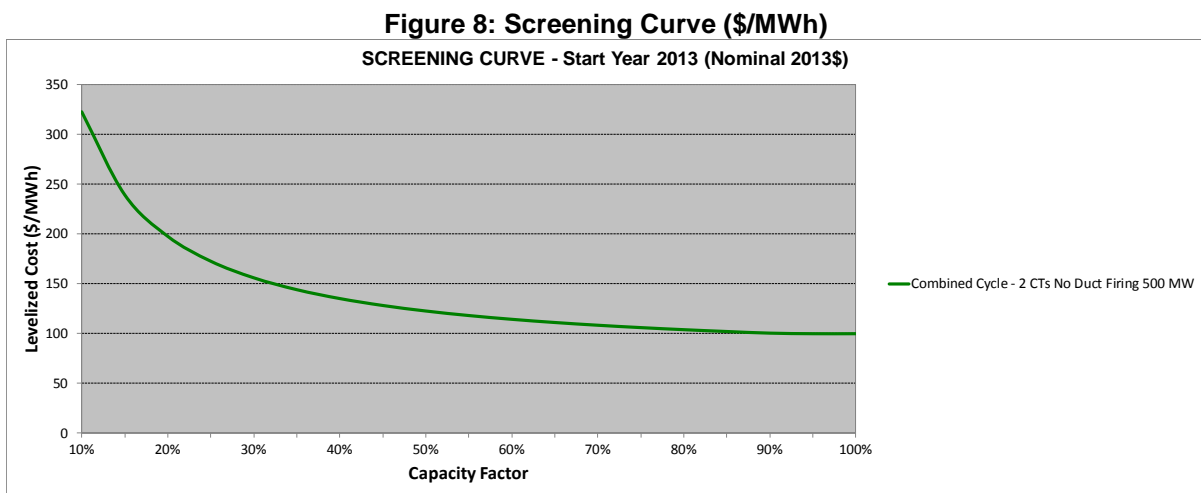
| | Levelized | NPV | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|--------------------|-----------|---------|------|------|------|------|------|------|------|------|------|------|------|------|-------|-------|-------|-------|-------|-------|-------|-------|
| Asset Rental Price | \$31 | \$424 | \$27 | \$27 | \$27 | \$28 | \$28 | \$29 | \$29 | \$30 | \$30 | \$31 | \$31 | \$31 | \$32 | \$32 | \$33 | \$33 | \$34 | \$35 | \$35 | \$36 |
| Fuel & O&M Costs | \$67 | \$901 | \$45 | \$47 | \$49 | \$53 | \$56 | \$56 | \$58 | \$59 | \$61 | \$63 | \$66 | \$67 | \$70 | \$71 | \$74 | \$76 | \$78 | \$80 | \$82 | \$85 |
| Total Costs | \$98 | \$1,325 | \$72 | \$74 | \$76 | \$80 | \$84 | \$84 | \$87 | \$89 | \$91 | \$93 | \$97 | \$99 | \$101 | \$104 | \$107 | \$110 | \$112 | \$115 | \$118 | \$120 |

Source: Energy Commission.

Screening Curve Function

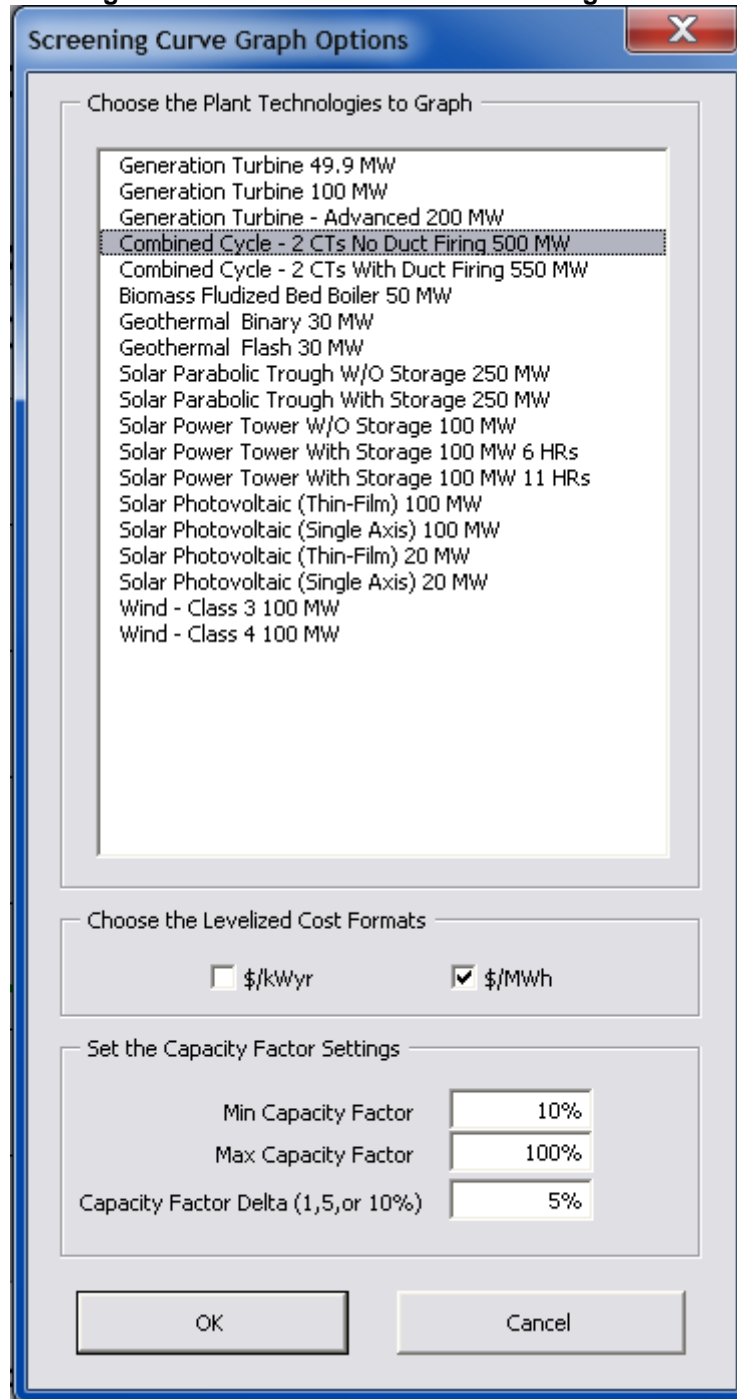
Screening curves allow the user to view the levelized cost for multiple capacity factors, rather than the singular capacity factor typical of cost of generation models. This allows the user to estimate levelized costs for specific assumption of capacity factor. It also allows the user to assess the cost risk of incorrectly estimating the capacity factor and for the comparison of various technologies as a function of capacity factor (i.e., at what capacity factor one technology becomes less costly than another).

The levelized costs of the screening curves can be shown as \$/MWh or \$/kW-yr. **Figure 8** illustrates a \$/MWh screening curve for a combined cycle (CC) unit with duct firing. **Figure 9** shows the corresponding interface window.



Source: Energy Commission.

Figure 9: Interface Window for Screening Curve



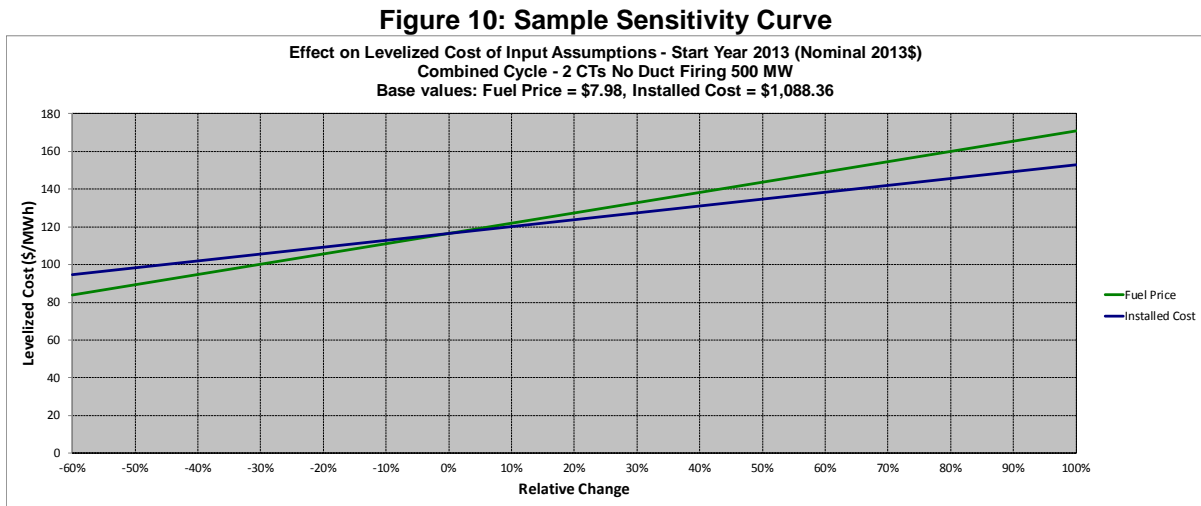
Source: Energy Commission

Sensitivity Curve Function

Although the screening curves are useful, they address only one variable when estimating levelized costs—the capacity factor. The new sensitivity curves address multiple assumptions: capacity factor, fuel prices, installed cost, discount rate weighted average cost of capital (WACC), percent equity, cost of equity, cost of debt, and other variables. Sensitivity curves show the effect on total levelized cost by varying any of these parameters in three formats:

- Levelized cost (\$/MWh or \$/kW-yr)
- Change in levelized cost as a percentage
- Change in levelized cost as incremental levelized cost from the base value (\$/MWh or \$/kW-yr).

Figure 10 illustrates a sample sensitivity curve. Figure 11 shows the interface window for the above sensitivity curve.



Source: Energy Commission.

Figure 11: Interface Window for Sensitivity Curves

Sensitivity Analysis Chart Options

Choose the Plant Technology

- Generation Turbine 49.9 MW
- Generation Turbine 100 MW
- Generation Turbine - Advanced 200 MW
- Combined Cycle - 2 CTs No Duct Firing 500 MW
- Combined Cycle - 2 CTs With Duct Firing 550 MW
- Biomass Fluidized Bed Boiler 50 MW
- Geothermal Binary 30 MW
- Geothermal Flash 30 MW
- Solar Parabolic Trough W/O Storage 250 MW
- Solar Parabolic Trough With Storage 250 MW
- Solar Power Tower W/O Storage 100 MW
- Solar Power Tower With Storage 100 MW 6 HRs

Choose the Levelized Cost Value

\$/MWh \$/kW-Yr

Choose the Ordinate Type

Levelized Cost

Change in Levelized Cost (%)

Change in Levelized Cost (\$/MWh)

Choose the Variables

Capacity Factor Percent Equity

Fuel Price Cost of Debt

Installed Cost Cost of Equity

Discount Rate (WACC) Fixed O&M

Loan Term Variable O&M

Book Life

Set Variable Parameters

Minimum Change in Variable -60%

Maximum Change in Variable 100%

Delta 10%

OK Cancel

Source: Energy Commission.

Yearly Costs Function

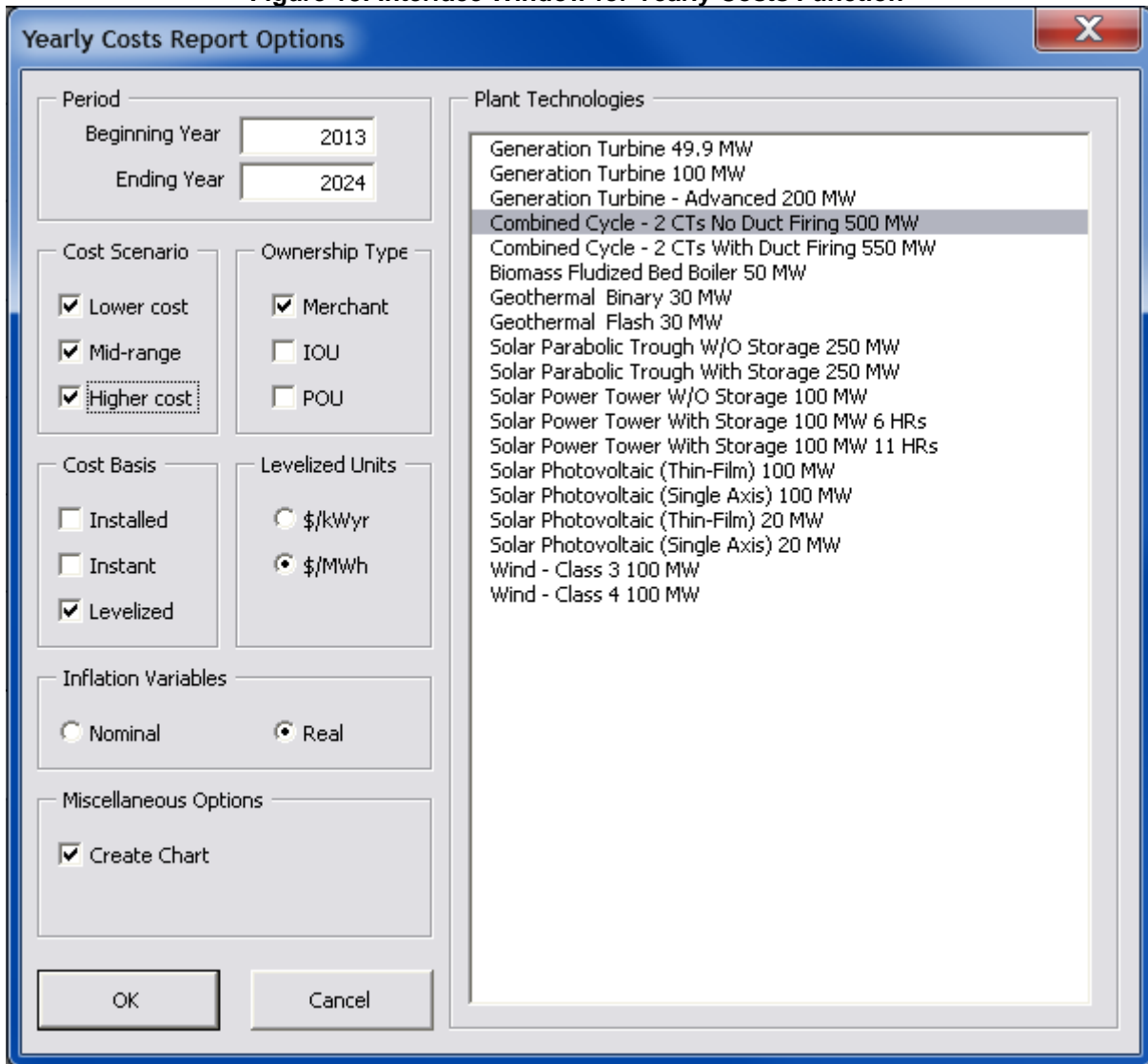
The yearly costs function calculates and plots instant, installed, and levelized over a range of years, across developer types, technology types, and cost levels. **Figure 12** illustrates the output and **Figure 13** the interface window.

Figure 12: Yearly Costs Function—Levelized Costs



Source: Energy Commission.

Figure 13: Interface Window for Yearly Costs Function



Source: Energy Commission.

Print Tables Function

The print tables function calculates levelized costs and the components for a specified year for all technologies, and presents them by developer in both \$/kW-Year and \$/MWh. This function allows for two scenarios to be run so that their difference, both numerically and by percentage, are apparent.

CHAPTER 4: Detailed Description of Worksheets

This chapter provides detailed descriptions of the components of the COG Model worksheets that have not been provided elsewhere. This does not include all items in the model as some are self-evident. Terminology not defined herein is defined in Appendix A: Definitions.

Input-Output Worksheet


The input-output worksheet has four components:

- Input Selection Panel
- Input Base Conditions
- Output Results Table
- Summary of Data Assumptions

Input Selection Panel

Figure 14 is a detailed description of the input selection panel (same as **Figure 6**).

Figure 14: Input Selection Panel

| <u>INPUT SELECTION</u> | |
|--|---|
| Step 1: Select Developer and Financing | Merchant Fossil |
| Step 2: Select Start-Year | 2013 |
| Step 3: Select Technology | Combined Cycle - 2 CTs No Duct Firing 500 MW |
| Step 4: Select Tax Loss Treatment | Tax Minimum Equals Zero |
| <u>FOR GAS-FIRED UNITS ONLY</u> | |
| Step 5: Select Carbon Price | Carbon Price Mid |
| Step 6: Select Natural Gas Price | CA Average |
| Step 7: Select Plant Site Region | CA - Avg. |
| Step 8: Click the Execute Button |  |

Source: Energy Commission.

- Developer and Financing—allows the macro to select the financing assumptions particular to the developer, depending on whether the technology is gas-fired or renewable as follows:
 - Merchant Fossil—a gas-fired technology that is merchant financed
 - Merchant Alternative—a renewable technology that is merchant financed
 - IOU Fossil—a gas-fired technology that is financed by an IOU
 - IOU Alternative—a renewable technology that is financed by an IOU
 - POU—a gas-fired or renewable technology that is financed by a POU
- Start-Year—the year the technology goes online and generates power. The start year sets the beginning of the study period and the year for which the levelized costs are reported.
- Technology—allows the macro to select the technology and associated fuel type.
- Select Tax Treatment—three options:
 - Tax Equity Financing: The developer takes full advantage of the tax incentives.
 - Tax Minimum Equals Zero: The developer takes partial advantage of the tax incentives.
 - Recovered Through Federal Tax Grant: An option from the 2009 IEPR that is no longer applicable and is provided for reference only.

- Carbon Price—sets the carbon price as mid, high, or low case value. The 2013 IEPR COG study used mid case, only. High and low case LCOEs were developed on a probabilistic basis using ACAT.
- Natural Gas Price—mid, high, or low case values as appropriate.
- Plant Site Region—sets the regional ERC values and water supply costs.

Input Base Conditions

The input base conditions panel is shown in **Figure 15**. These conditions affect this LCOE operation and others discussed later. For this LCOE function, these are generally set as shown.

Figure 15: Input Base Conditions
INPUT BASE CONDITIONS

| | |
|--|---------------------------------|
| Cost Scenario (Select) | Mid Case |
| General Assumptions (Select) | Default |
| Base Year (All Costs In 2011 Dollars) | 2011 |
| Fuel Type (Accept Default) | Natural Gas |
| <i>Data Source</i> | <i>Aspen 2-20-13</i> |
| Study Perspective (Select) | At Interconnection Point |
| Reported Construction Cost Basis (Select) | Instant |

Source: Energy Commission.

Only the last two functions affect the discussed LCOE function:

- Study Perspective—can be set to any of the following physical locations, but is generally set to "At Interconnection Point":
 - At bus-bar plant side—low side of the power plant uplift transformer
 - At bus-bar transmission side—high side of the power plant uplift transformer
 - At Interconnection Point—where the power plant interconnects with the existing transmission system
- Reported Construction Cost Basis—can be either of the following (for the present studies, it is set to "Instant").
 - Instant—costs entered on the PTA worksheets are instant, not installed costs
 - Installed—costs entered on the PTA worksheets are installed, not instant costs. As the COG Model is presently set up, it will not work correctly with this option. The data and operation would have to be altered dramatically. The ancillary costs, such as transmission, are set for instant costs and would need to be revised. The installed costs would have to be set to a singular value, but in reality, they vary depending on the developer. So no IOU or POU installed costs could be developed at the same time.

Output Results Panel

The following is a description of the terms used in the output results panel (LCOE), repeated from **Table 6**. This table shows the LCOEs as both \$/kW-yr and \$/MWh. The \$/kW-yr come

from the income worksheets. The \$/MWh values are then calculated by multiplying the \$/kW-yr value by gross capacity and then dividing by the study energy explained below. Fixed cost calculations are typically calculated as \$/kW-yr and variable costs are typically calculated as \$/MWh. The model uses \$/kW-yr.

Table 6: Output Results Panel

| OUTPUT RESULTS - Summary of Levelized Costs | | | | | | |
|---|-----------------|-----------------|------------------|-----------------|-----------------|----------------|
| Combined Cycle - 2 CTs No Duct Firing 500 MW | | | | | | |
| Merchant Fossil | Mid Case | | High Case | | Low Case | |
| Start Year = 2013 (2013 Dollars) | \$/kW-Yr | \$/MWh | \$/kW-Yr | \$/MWh | \$/kW-Yr | \$/MWh |
| Capital & Financing - Construction | \$114.37 | \$24.16 | \$190.21 | \$57.88 | \$63.93 | \$10.67 |
| Insurance | \$7.72 | \$1.63 | \$8.76 | \$2.67 | \$6.09 | \$1.02 |
| Ad Valorem Costs | \$11.19 | \$2.36 | \$11.91 | \$3.62 | \$8.54 | \$1.43 |
| Fixed O&M | \$43.23 | \$9.13 | \$94.65 | \$28.80 | \$17.69 | \$2.95 |
| Corporate Taxes (w/Credits) | \$37.77 | \$7.98 | \$71.90 | \$21.88 | \$8.81 | \$1.47 |
| Fixed Costs | \$214.28 | \$45.27 | \$377.43 | \$114.85 | \$105.06 | \$17.54 |
| Fuel & GHG Emissions Costs | \$333.39 | \$70.44 | \$283.59 | \$86.29 | \$267.61 | \$44.69 |
| Variable O&M | \$3.75 | \$0.79 | \$7.49 | \$2.28 | \$1.50 | \$0.25 |
| Variable Costs | \$337.14 | \$71.23 | \$291.08 | \$88.57 | \$269.10 | \$44.94 |
| Total Levelized Costs At Interconnection Point | \$551.42 | \$116.51 | \$668.51 | \$203.42 | \$374.16 | \$62.48 |

Source: Energy Commission.

- Capital and Financing Costs—all capital costs plus associated financing costs. The capital cost includes all equipment, land, permitting, and interconnection costs. Financing costs are those incurred through debt and equity financing and are incurred annually by the developer. The costs shown are the levelized cost of these annual costs.
- Insurance Cost—the cost of insuring the power plant. For a merchant/POU the first year cost is estimated as a percentage of the installed cost per kilowatt (kW) and then escalated by forward inflation throughout the book life (period of the calculations). For an IOU plant, the annual cost is a percentage of the book value/rate base, and the subsequent yearly cost decreases over time.
- Ad Valorem Cost—annual property tax payments that are paid as a percentage of the assessed value and usually transferred to local governments. POU power plants are generally exempt from these taxes but may pay in-lieu fees. The assessed values for power plants are set by the Board of Equalization as a percentage of book value for an IOU and as depreciation-factored value for a merchant facility.
- Fixed O&M Costs—annual costs regardless of how much the plant operates. These are not uniformly defined but generally include staffing, overhead, equipment (including leasing), regulatory filings, and other direct costs.
- Corporate Taxes—state and federal taxes, which are not applicable to a POU. The federal taxes are reduced by the state taxes similar to adjustment rates for a homeowner.

- Fuel Cost—the cost of fuel used by the power plant is commonly expressed in \$/MWh. For a thermal power plant, it is the heat rate (British thermal unit per kilowatt-hour [Btu/kWh]) multiplied by the cost of the fuel (\$/MMBtu). This includes start-up fuel costs and on-line operating fuel usage. Allowance is made for the degradation of the heat rate over time.
- Variable O&M—these costs are a function of the hours of operation of the power plant, including annual maintenance and overhauls. Variable O&M also includes repairs for forced outages, consumables, water supply, and annual environmental costs.³

The costs are reported as mid, high, and low case LCOEs. Only the mid case is meaningful for this report. The high and low case LCOEs reflect the effect of all high/low cost values occurring simultaneously, which is highly unlikely. For high and low case LCOEs in the COG Report, the probabilistic analysis of the ACAT is used, which is a combination of the COG Model and Lumina's Analytical Model.

Summary of Data Assumptions

The following is a description of the terms used in the data assumptions panel (repeated here as **Table 7**), corresponding to the 2013 CC selection above. The data is brought forward from other worksheets in the COG Model for convenience.

³ Consumables refer to the variable costs of disposable materials associated with running the plant that is not otherwise accounted for.

**Table 7: Summary of Data
Assumptions—Combined Cycle with Start-Year 2013**

| DATA ASSUMPTIONS ASSOCIATED WITH YOUR INPUT SELECTION | | | | | | |
|--|--------------------------|----------------------------|--------------------------|----------------------------|--------------------------|----------------------------|
| Cost Case Assumptions | Mid Case | | High Case | | Low Case | |
| Capital & Operating Costs | Base Yr 2011 | Start Yr 2013 | Base Yr 2011 | Start Yr 2013 | Base Yr 2011 | Start Yr 2013 |
| Instant Cost (\$/kW) | \$956 | \$1,000 | \$1,093 | \$1,144 | \$779 | \$816 |
| Installed Cost (\$/kW) | \$1,040 | \$1,088 | \$1,257 | \$1,316 | \$805 | \$843 |
| Ratio of Installed Cost to Instant Cost | | 1.088 | | 1.150 | | 1.033 |
| Ratio of Installed Cost to Component Cost | | 1.2365 | | 1.467 | | 1.1519 |
| Fixed O&M Cost (\$/kW-Yr) | \$32.69 | \$34.56 | \$77.96 | \$82.42 | \$13.04 | \$13.79 |
| Variable O&M Cost (\$/MWh) | \$0.58 | \$0.61 | \$1.79 | \$1.89 | \$0.18 | \$0.19 |
| Total O&M (\$/MWh) | \$7.13 | \$7.54 | \$24.04 | \$25.42 | \$2.28 | \$2.41 |
| Total O&M (\$/kW-Yr) | \$35.59 | \$37.62 | \$84.23 | \$89.06 | \$14.16 | \$14.97 |
| Insurance (\$/kW-Yr) | \$6.24 | \$6.53 | \$7.54 | \$7.89 | \$4.83 | \$5.06 |
| Ad Valorem (\$/kW-Yr) | \$11.30 | \$11.83 | \$13.39 | \$14.01 | \$8.75 | \$9.16 |
| Operational Performance | Factor | Hours | Factor | Hours | Factor | Hours |
| Scheduled Outage Factor (SOF) | 6.02% | 527.4 | 6.02% | 527.4 | 6.02% | 527.4 |
| Forced Outage Rate (FOR) | 2.24% | 114.4 | 2.24% | 80.3 | 2.24% | 142.5 |
| Operational (Service) Hours Per Year | | 4,993.2 | | 3,504.0 | | 6,219.6 |
| Equivalent Availability Factor | 91.87% | | 91.87% | | 91.87% | |
| Capacity Factor | 57.00% | | 40.00% | | 71.00% | |
| Fuel Use Summary | 2013 | Levelized | 2013 | Levelized | 2013 | Levelized |
| Average Heat Rate (Btu/kWh) | 7,250 | 7,383 | 7,480 | 7,595 | 7,030 | 7,117 |
| Fuel Use (MMBtu) | 18,100,350 | 18,100,350 | 13,104,960 | 13,104,960 | 21,861,894 | 21,861,894 |
| Fuel Price (\$/MMBtu) | \$4.56 | \$7.11 | \$6.67 | \$9.32 | \$2.79 | \$3.83 |
| Financial Information | Cap Structure | Cost of Capital | Cap Structure | Cost of Capital | Cap Structure | Cost of Capital |
| Weighted Avg. Equity | | 13.25% | | 15.00% | | 10.41% |
| Equity | 33.0% | 13.25% | 60.0% | 15.00% | 20.0% | 10.41% |
| Tax Equity | 0.0% | 0.00% | 0.0% | 0.00% | 0.0% | 0.00% |
| Debt Financed: | 67.0% | 4.52% | 40.0% | 6.63% | 80.0% | 4.64% |
| Discount Rate (WACC) | 6.17% | 4.53% | 10.57% | 8.84% | 4.28% | 2.68% |
| Inflation Rate From Base Yr. To Start Yr. | 2.31% | | 2.31% | | 2.31% | |
| Inflation Rate From Start Year Forward | 1.56% | | 1.59% | | 1.56% | |
| Loan/Debt Term (Years) | 10 | | 7 | | 20 | |
| Equipment Life (Years): | 30 | 12/31/2042 | 20 | 12/31/2032 | 30 | 12/31/2042 |
| Economic/Book Life (Years) | 30 | | 20 | | 30 | |
| Federal Tax Life (Years) | 20 | | 20 | | 20 | |
| State Tax Life (Years) | 20 | | 20 | | 20 | |
| Capacity and Energy | Effective | Energy | Effective | Energy | Effective | Energy |
| Gross (Dependable) | 500.0 | 2451.7 | 500.0 | 1725.5 | 500.0 | 3071.7 |
| Net Capacity - Plant Side | 485.5 | 2380.6 | 480.0 | 1656.5 | 490.0 | 3010.3 |
| Net Capacity - Transmission Side | 483.1 | 2368.7 | 477.6 | 1648.2 | 487.6 | 2995.2 |
| At Interconnection Point | 482.6 | 2366.5 | 476.1 | 1643.1 | 487.4 | 2994.3 |
| | | | | | | |
| Merchant Fossil | Mid-Cost Case | | High-Cost Case | | Low-Cost Case | |
| Debt Service Coverage Ratios - Average | 1.52 | | 2.61 | | 1.37 | |
| Debt Service Coverage Ratios - Minimum | 1.42 | | 2.48 | | 1.27 | |

Source: Energy Commission.

Most values in **Table 7** are self-explanatory. Less evident are:

- Instant Costs—total instant cost including all ancillary costs such as land, permitting, and licensing.
- Installed Cost—instant cost plus financing and developmental costs (predevelopment expenses, construction insurance, and installation, commitment fee, and debt arrangement fees).
- Ratio of Installed Cost to Instant Cost—ratio of the two values above.
- Ratio of Installed Cost to Component Cost—ratio of the above installed cost to component instant cost (without ancillary costs, such as land and licensing). These ratios are often useful in tracking costs.
- Total O&M—since different estimates reflect different portions of the O&M split into fixed and variable components, total O&M allows the only logical basis for comparison of estimates. Total O&M is calculated both in \$/kW-Year and \$/MWh.⁴
- Schedule outage factor (SOF) and forced outage rate (FOR) are informational only as they do not affect the calculated levelized costs. SOF and FOR are as defined by North American Electric Reliability Council/GADS. For simplicity, this value is stated in terms of full outages; however, the values provided include both full and partial outages. A more complete definition can be found in **Appendix A**.
- Average Heat Rate—calculated based on actual operating data (California Energy Commission [CEC] Quarterly Fuels and Energy Report [QFER] data), and represents start-up and variations in power level during operation. It is the nominal known actual operating value.
- Capacity Factor (CF)—data is collected as net capacity factor (NCF) (CEC QFER data), measured at the net output bus bar value. In the COG Model, the net and gross capacity factors are identical.
- Discount Rate (WACC)—stated and applied as the after tax WACC.
- Inflation Rate From Base Yr. To Start Yr. and Inflation Rate From Start Year Forward—to simplify inflation calculations, singular values are used. Singular values are calculated as the average annual values for the respective periods, taking into account the start year and book life.

Physical Data Worksheet

This worksheet holds key data that the model's macro collects from the assumptions worksheets, and in some cases performs minor calculations. There are three tables on this worksheet:

- Plant Capacity and Energy Data Table—capacity, energy, and losses
- Operational Performance Data Table—percent output, percent of year operational, outage, capacity, and availability factors

⁴ To convert from \$kW-Year to \$/MWh multiply by gross MW and divide by study gigawatt hour (GWh).

- Fuel Use Data Table—heat rates, degradation factors, and startup fuel use

Plant Capacity and Energy Data Table

Table 8 shows the plant capacity and energy data for the 500 MW CC with no duct-firing technology.

Table 8: Plant Capacity and Energy Data

| Plant Capacity & Energy Data | | Effective Capacity (MW) | Average Annual Energy (GWh) |
|--|---------------|-------------------------|-----------------------------|
| Gross Capacity (MW) | 500.00 | 500.00 | 2451.71 |
| Plant Losses | 2.90% | | |
| Net Capacity (MW) - Plant Side | 485.50 | 485.50 | 2380.61 |
| Transformer Losses | 0.50% | | |
| Net Capacity (MW) - Transmission Side | 483.07 | 483.07 | 2368.71 |
| Generator Tie Lie Losses | 0.09% | | |
| Capacity at Interconnection Point (MW) | 482.62 | 482.62 | 2366.51 |
| Annual Capacity Degradation Rate | 0.18% | | |
| STUDY PERSPECTIVE | 482.62 | 482.62 | 2366.51 |

Source: Energy Commission.

- Gross Capacity—capacity at the generation level. For solar technologies, this is the direct current (DC) power level, which is not typically measured. The turquoise shaded area shows the gross MW as taken from the plant type assumptions worksheet. Effective capacity reflects the average MW when running. Average annual energy is generated by the plant allowing for capacity degradation. If the capacity degradation is set to zero, then the energy will equal the gross MW times the capacity factor times 8.76. The calculation of this energy allowing for capacity degradation is described under “**Calculation of Energy Allowing for Capacity Degradation.**”
- Plant Losses—the percentage of power consumed for on-site uses plus any DC to AC conversion losses (applicable to non-photovoltaic [PV] solar technologies only). Solar PV has been revised to AC output, thus removing the need for plant side losses in its calculation.
- Net Capacity-Plant Side—capacity at the power plant busbar, allowing for plant losses. This is at the low side of the uplift transformer. The effective capacity and energy calculations are the same as for the gross MW, except they are now based on net capacity MW.
- Transformer Losses—power lost in the uplift transformer that converts the power plant voltage to transmission line voltage.
- Net Capacity-Transmission Side—capacity at the transmission busbar, which is the high side of the uplift transformer. Associated values are calculated the same as before except they are based on the new lower available capacity.

- Transmission Interconnection Losses—losses associated with the interconnection equipment (from the power plant to the interconnection with the existing transmission system).
- Annual Capacity Degradation Rate—power lost due to degradation of the generating equipment. This is an average annual value that allows for periodic improvement due to maintenance overhauls, and is described below. For geothermal, this also captures the degradation of the steam field. At present the same value is used for the annual heat rate degradation rate.
- Study Perspective—power at the various perspectives as chosen by the user: at busbar—plant side, at busbar—transmission side, or at interconnection point. The last option will typically be selected.
- The effective capacity column is the same data but multiplied by the average output percent. It is in effect average MW.

Calculation of Energy Allowing for Capacity Degradation

The average annual energy values are the energy quantities as affected by capacity degradation. Absent capacity degradation, this would be the gross MW times the capacity factor times 8.76. However, the actual energy quantity is complicated by the effect of capacity degradation. The energy quantity with capacity degradation is calculated using the following formulas, where payment function (PMT) is the annual payment, which is the levelized cost. To be assured that this is a valid computation without examining the calculations, verify that the value in cell E19 (in this case 2,451.71 GWh) is identical to the value in cell D7 of the cash-flow and income revenue requirement worksheets.

- Average Annual Energy for Gross Capacity— $PMT(\text{rate}, \text{nper}, \text{pv})$
 - Rate (Interest Rate) = DiscountRate
 - Nper (number of periods) = BookLife
 - Pv (Present Value) = $PV((1 + \text{DiscountRate}) / (1 - \text{AnnCapDegredationRate}) - 1, \text{BookLife}, \text{OpHrsPerYr} * \text{GrossMW} / 1000 * \text{AverageOutputPct})$
- Average Annual Energy for Net Capacity—Plant Side: $PMT(\text{rate}, \text{nper}, \text{pv})$
 - rate (interest rate) = Discount Rate
 - nper (number of periods) = Book Life
 - pv (Present Value) = $PV((1 + \text{DiscountRate}) / (1 - \text{AnnCapDegredationRate}) - 1, \text{BookLife}, \text{OpHrsPerYr} * \text{OpCapMW} / 1000)$
- Average Annual Energy for Net Capacity—Transmission Side: $PMT(\text{rate}, \text{nper}, \text{pv})$
 - rate (interest rate) = DiscountRate
 - nper (number of periods) = BookLife
 - pv (Present Value) = $PV((1 + \text{DiscountRate}) / (1 - \text{AnnCapDegredationRate}) - 1, \text{BookLife}, \text{OpHrsPerYr} * \text{OpCapMW} * \text{TransformerLosses} / 1000)$

In each of the above cases, an average energy value, PMT, is determined by first calculating a net present value (NPV) of the actual energy values and then using that NPV to find the levelized energy value, PMT, similar to what is done in the income statement worksheet for

dollar values. This calculation of the NPV is subtle and can best be illustrated using simplified nomenclature. If E_t is the annual decreasing energy values for years (t), 0 through N, then $E_t = E_c(1-CD)^t$, where E_c is the annual energy in the absence of capacity degradation and CD is the capacity degradation factor. Each of the annual degraded values of this energy series can be converted to a present value by dividing by the factor $(1+DR)^t$, where DR is the discount rate and t is number of the year. The NPV of the entire series can be represented as:

$$NPV = \sum_{t=1}^N \frac{E_t}{(1+DR)^t} = \sum_{t=1}^N \frac{E_c(1-CD)^t}{(1+DR)^t}$$

This can be easily rearranged to:

$$NPV = \sum_{t=1}^N \frac{E_c}{(1+DR)^t / (1-CD)^t} = \sum_{t=1}^N \frac{E_c}{[(1+DR)/(1-CD)]^t}$$

Adding 1 and subtracting 1 in the denominator, as shown, does not change the value but puts this in a more usable form:

$$NPV = \sum_{t=1}^N \frac{E_c}{[1 + (1+DR)/(1-CD) - 1]^t} = \sum_{t=1}^N \frac{E_c}{(1+i)^t}; \text{ where } i = [(1+DR)/(1-CD)] - 1$$

The formula is now a present value of constant value E_c , where the interest rate is equal to

$$[(1+DR)/(1-CD)] - 1$$

To illustrate how this works in Excel, the gross MW energy case is:

- $pv = (\text{rate}, \text{nper}, \text{pmt})$
 - $\text{rate} = i = [(1+DR)/(1-CD)] - 1 = [(1+\text{DiscountRate})/(1-\text{AnnCapDegradationRate})] - 1$
 - $\text{nper} = \text{BookLife}$
 - $\text{pmt} = E_c = \text{OpHrsPerYr} * \text{GrossMW} / 1000 * \text{AverageOutputPct}$
- Average Annual Energy for Gross Capacity—PMT (rate, nper, pv)
 - rate (Interest Rate) = DiscountRate
 - nper (number of periods) =, BookLife,
 - npv (Net Present Value) = NPV ((1+DiscountRate)/ (1-AnnCapDegredationRate)-1, BookLife, OpHrsPerYr*GrossMW/1000* AverageOutputPct))

The final division by “(1-AnnCapDegradation)” is for aligning the yearly values of the degradation factor with those of the discount rate.

Operational and Performance Data

Table 9 shows the operational and performance data table for the CC unit without duct-firing technology.

Table 9: Operational and Performance Data

| Operational Performance Data | | Hours/Yr |
|--|---------|----------|
| Average Percent Output | 100.00% | |
| Scheduled Availability (Economic & Physical) | 58.3% | 5,108 |
| Number Of Annual Starts | 25 | |
| Scheduled Outage Hours | 527 | |
| OR Scheduled Outage Factor | 6.02% | |
| Modeled Scheduled Outage Factor | 6.02% | 527 |
| Final Planned Operational Hours | | 5,108 |
| Forced Outage Rate (FOR) | 2.24% | 114 |
| Operational (Service) Hours Per Year | | 4,993 |
| Total Operating Hours Over Life Of Plant | | 149,796 |
| Equivalent Availability Factor | 91.87% | |
| Net Capacity Factor (NCF) | 57.00% | |

Source: Energy Commission.

- Average Percent Output—used for generating technologies, such as solar and wind, with variable outputs. This factor estimates the average MWs for these units during operation. For example, a solar PV may have the potential to achieve 100 MW, but will typically be below that value so that it is assigned an average of 85 MW over the year. Accordingly, the average output is 85 percent ($85/100 = 0.85 = 85$ percent).
- Scheduled Availability—used to capture the effect of economic dispatch and to adjust the capacity factor for any unit with limited operational hours due to economic dispatch. Scheduled availability is used primarily for conventional generating units as renewable technologies are allowed to run base loaded in the model (that is, they are not curtailed by economic dispatch). The model uses net CF, forced outage factor, and SOF as inputs to calculate the planned percentage of year operational factor (scheduled availability).
- Scheduled Outage Hours and Factor—scheduled outage hours (SOH) are those hours when the power plant is on scheduled maintenance. This includes annual maintenance and forced or “maintenance outages” that can be delayed beyond the next weekend. These definitions are created by the North American Electric Reliability Council’s Generating Availability Data Service (GADS) unit, and are explained in Appendix A. The outages calculated as a percentage of the total year are called SOF. In the COG Model, $SOF = SOH / 8,760$ hours.
- Final Planned Operational Hours—hours when the plant is not on annual maintenance.
- Outage Hours and Rate—the forced outage hours (FOH) and forced outage rate (FOR) are a measure of the power plant’s reliability. FOH are those hours when a power plant is forced out of operation due to equipment failure. For the simplest case when a plant is either operating at full power or forced off-line, the FOR is the ratio of the FOH to those hours when the plant is operational (FOH+service hours [SH]). Hours when the plant is not called on to operate are not applicable to the calculation.

Accordingly, $FOR = FOH / (FOH + SH)$, where SH is the service hours. For simplification, these terms are used in the COG Model, but they are not strictly accurate in that there are partial outages where the plant operates at partial power. To capture this subtlety, equivalent FOH and FOR should be entered into the model. FOR becomes equivalent forced outage rate (EFOR) and the formula becomes more complicated, but in its simplest form, it is $EFOR = (FOH + EFDH) / (FOH + SH + EFDHRS)$.⁵ The exact formula has been further complicated by recent North American Electric Reliability Council/GADS definitions. The formula is further defined in Appendix A.

- Operational (Service) Hours Per Year (SH)—the number of hours that the plant is operational in any one year.
- Total Operational Hours Over the Life of Plant—yearly operational hours times the number of years in the study.
- Equivalent Availability Factor (EAF)— the percentage of the year that the plant is available to operate, if called upon. That is, the percentage of the year that the plant is not on maintenance and not forced out, calculated as: $AF = (1 - FOR) * (1 - SOF)$. Recall that FOR is really EFOR and SOF is really Equivalent SOF (ESOF). For this more exact case, AF becomes EAF. This formula is further defined in Appendix A.
- Net Capacity Factor—how much the plant is used. This factor is equal to the ratio of the energy generated by the power plant to the energy that could be generated if it operated at full power for the entire year. The word “Net” signifies that the net capacity is used—although in the model, the same CF is applicable both on the gross and net MW level.

Fuel Use Data

Table 10 shows fuel use for the CC without duct-firing technology.

Table 10: Fuel Use Table

| Fuel Use | | | Efficiency |
|--------------------------------|------------|-------------|------------|
| Annual Average Heat Rate (HHV) | | | |
| Operating Heat Rate | 7,250 | Btu/kWh | 47.1% |
| Adjusted Net Of Startup | 7,236 | Btu/kWh | 47.2% |
| Annual Heat Rate Degradation | 0.18% | | |
| Fuel Consumption/Hour | 3,618 | MMBtu/Hr | |
| Start Up Fuel Use | 1,400 | MMBtu/Start | |
| Average Annual Fuel Use | 18,100,350 | MMBtu | |

Source: Energy Commission.

⁵ EFDH is equivalent forced derated hours, and EFDHRS is equivalent forced derated hours during reserve shutdown.

- Annual Average Heat Rate (high heating value):
 - Operating Heat Rate—the average heat rate provided in the plant type assumptions worksheet is automatically populated in this table by the macros. The gas-fired heat rates are calculated based on regressions of the QFER data base, calculated as the total BTUs used divided by the kWh generated. This captures the effect of operational variation and startups.
 - Adjusted Net of Startups—the heat rate that would occur not accounting for the energy used in startups; as such, it is a better heat rate (smaller number). This is estimated by assuming an annual number of startups and the fuel used in each. The estimate has no effect on the actual average heat rate as that rate is calculated based on QFER data, which captures all fuel usages including startup fuel. The heat rate net of startups is calculated by backing out the estimated startup fuel usage (number of starts multiplied by the fuel per start).
- Annual Heat Rate Degradation—the decrease in heat rate due to degradation of the generating equipment. This is an average annual value that allows for periodic improvement due to maintenance overhauls. This calculation is identical to the annual capacity degradation rate; both are defined under “Calculation of the Capacity and Heat Rate Degradation Rate.”
- Fuel Consumption/Hour—the operating heat rate (net of startups) times CF, times gross MWs.
- Start-Up Fuel Use—calculated exogenous to the COG Model (using the Commission’s Production Cost Model output) and entered into the plant type assumptions tables.
- Average Annual Fuel Use—the sum of the operating fuel use and the start-up fuel use taken from the revenue income statement.

Annual Capacity and Heat Rate Degradation for Gas-Fired Units

As the plant ages, both the capacity and heat rate degrade. These are measured as degradation factors that represent the percentage per year that the capacity will decrease and the heat rate will increase. The increases are driven by normal wear and tear on the generation turbine, but are mitigated by maintenance. The heat rate degradation for units other than the CC and CT was provided by Aspen Environmental Group, as documented in the 2013 IEPR Cost of Generation Report. The heat rate degradation for the gas-fired units is a function of capacity factor and was calculated for the 2013 IEPR as summarized in

Table 11. The counterintuitive relationship of the low degradation factors being higher than the high degradation factors due to the relative CFs, is explained below.

Table 11: Summary of Capacity and Heat Rate Degradation Factors

| Technology Case | Owner | Degradation Factors | | |
|--|------------|---------------------|--------|--------|
| | | Mid | High | Low |
| Conventional Combustion Turbine (Both Sizes) | Merchant | 0.055% | 0.082% | 0.027% |
| | POU | 0.082% | 0.153% | 0.044% |
| | IOU | 0.011% | 0.011% | 0.011% |
| Advanced Combustion Turbine | Merchant | 0.082% | 0.124% | 0.042% |
| | POU | 0.124% | 0.230% | 0.066% |
| | IOU | 0.016% | 0.016% | 0.016% |
| Conventional Combined Cycle | All Owners | 0.178% | 0.240% | 0.108% |
| Conventional Combined Cycle w/Duct Burners | All Owners | 0.178% | 0.240% | 0.108% |

Source: Energy Commission.

These degradation estimates are based on a December 7, 2005, email from James Shoonmaker to Will Walters, which incorporates General Electric Technical Bulletin GER-3567H (Attachment C). General Electric’s rule is that SC units degrade 3 percent every 24,000 hours, at which time they receive an overhaul and return to 1 percent degradation (that is, they recover two-thirds of the degradation). The degradation factors are therefore a function of CF. This calculation can be illustrated using the CFs from the 2013 IEPR shown in **Table 12**. Based on these CFs the duration between overhaul can be calculated for the mid cost case as shown in **Table 13**.

Table 12: Natural Gas Technologies Capacity Factors for the 2013 IEPR

| Technology Case | Owner | Assumed Capacity Factor | | |
|--|------------|-------------------------|-------|------|
| | | Mid | High | Low |
| Conventional Combustion Turbine (both sizes) | Merchant | 5.0% | 7.5% | 2.5% |
| | POU | 7.5% | 14.0% | 4.0% |
| | IOU | 1.0% | 1.0% | 1.0% |
| Advanced Combustion Turbine | Merchant | 7.5% | 11.3% | 3.8% |
| | POU | 11.3% | 21.0% | 6.0% |
| | IOU | 1.5% | 1.5% | 1.5% |
| Conventional Combined Cycle | All Owners | 57% | 71% | 40% |
| Conventional Combined Cycle w/Duct Burners | All Owners | 57% | 71% | 40% |

Source: Energy Commission.

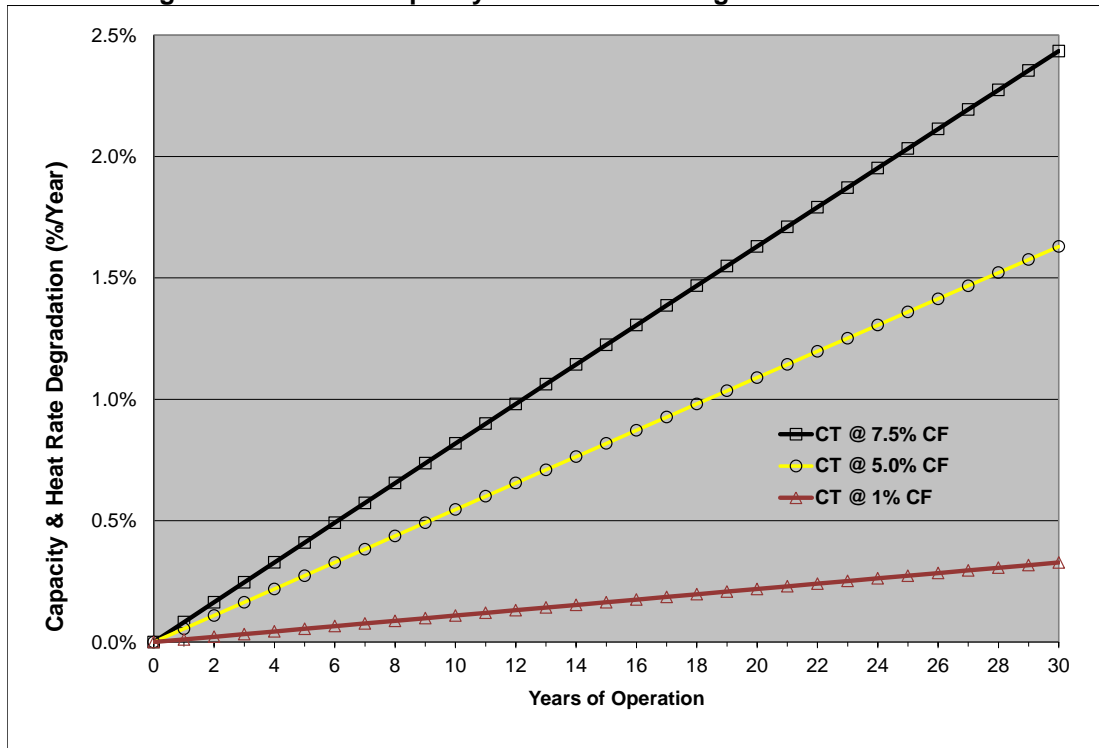
Table 13: Years Between Overhauls vs. Capacity Factor—Mid Cost

| Technology | Assumed Capacity Factor | Years Between Overhauls |
|------------------------------|-------------------------|-------------------------|
| Merchant Combustion Turbines | 5% | 55 |
| IOU Combustion Turbines | 1% | 274 |
| POU Combustion Turbines | 7.5% | 37 |
| Advanced Combustion Turbines | 7.5% | 37 |
| Combined Cycle Units | 57% | 4.8 |

Source: Energy Commission.

None of the SC units will require an overhaul during the 30 year book life used in the COG Model, so the calculation of their degradation factors is simple. For the Merchant SC mid case capacity factor of 5 percent, an overhaul will not be necessary for 55 years ($24,000 \text{ hrs}/(8760 \times 0.05 \text{ hrs/yr}) = 54.8 \text{ yrs}$) and the degradation factor can be calculated a 0.055 percent a year ($1.64\%/30 \text{ years} = 0.055\%$). The IOU and POU degradation factors can be similarly calculated at 0.011 percent and 0.082 percent, respectively. These degradation factors are illustrated in **Figure 16**.

Figure 16: Turbine Capacity and Heat Rate Degradation—Mid Cost

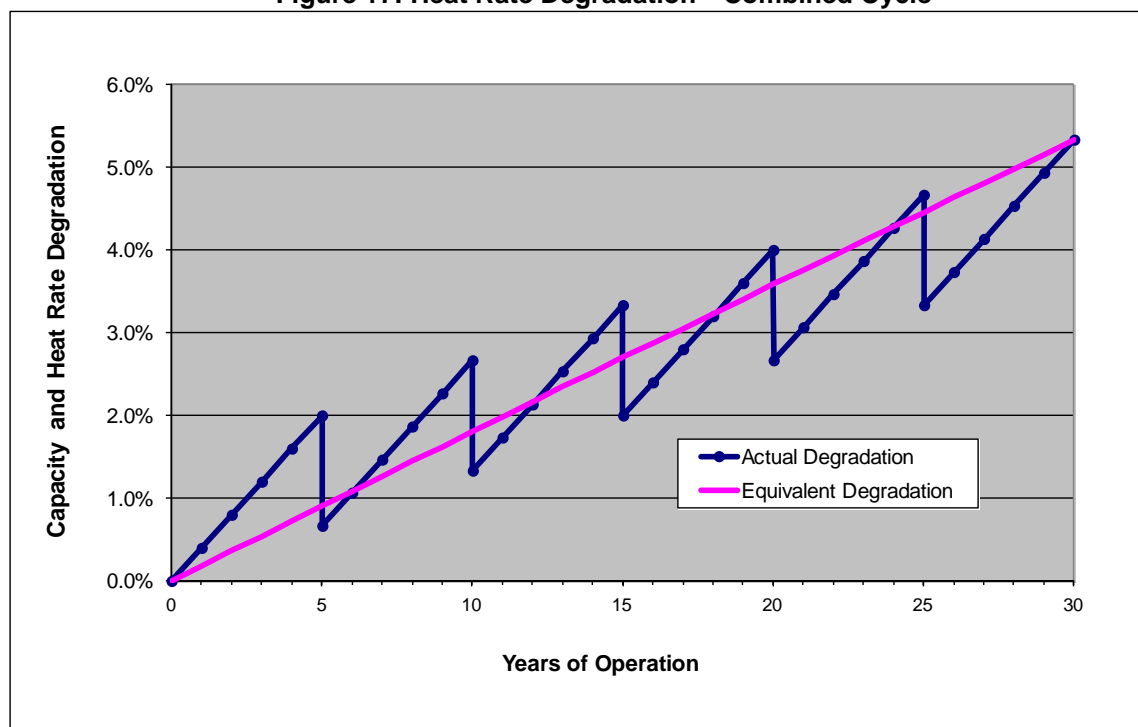


Source: Energy Commission.

The computation for the CC units is more complex due to its higher CF, estimated to be 57 percent for all developers, which calls for an overhaul every 4.8 years. Approximating this as 5 years results in 5 major overhauls during its 30-year book life, as shown in **Figure 17**. Since the steam generator portion remains essentially stable, the overall system deteriorates 2 percent ($2/3 \times 3$ percent) during the 5-year period and recovers two-thirds of its deterioration (1.33 percent) during the overhaul (net degradation of 0.67 percent). Each subsequent end of degradation point and recovery point is 0.667 percent higher than the last. This gives an end point at 30 years of 5.33 percent. The equivalent degradation of 0.18 percent can be calculated as the slope of the line that has the equivalent area under the curve ($5.33\text{percent}/30 = 0.1778$ percent).

Note that these are approximations; there are alternative approximations proposed by others. The point is that, for the gas-fired technologies, the effect of degradation is quite small so that approximations account for very small errors. **Table 14** is a summary of the combined effect of capacity and heat rate degradation for the technologies under study. For the gas-fired technologies, the effect on \$/MWh LCOE is to increase it by 1.5 percent or less depending on the developer. Any error in replicating the gas-fired technology degradation will be a percentage of that—not worthy of additional effort.

Figure 17: Heat Rate Degradation—Combined Cycle



Source: Energy Commission.

Table 14: Effect of Capacity and Heat Rate Degradation on LCOE

| In-Service Year =2013 (Nominal 2013\$) | Size | Merchant | | IOU | | POU | |
|--|------|----------|--------|----------|--------|----------|--------|
| | MW | \$/kW-Yr | \$/MWh | \$/kW-Yr | \$/MWh | \$/kW-Yr | \$/MWh |
| Generation Turbine 49.9 MW | 49.9 | -0.2% | 0.3% | -0.1% | 0.4% | -0.1% | 0.7% |
| Generation Turbine 100 MW | 100 | -0.2% | 0.3% | -0.1% | 0.4% | -0.1% | 0.7% |
| Generation Turbine - Advanced 200 MW | 200 | -0.3% | 0.5% | -0.2% | 0.6% | -0.1% | 0.9% |
| Combined Cycle - 2 CTs No Duct Firing 500 MW | 500 | -0.8% | 1.1% | -0.6% | 1.1% | -0.8% | 1.5% |
| Combined Cycle - 2 CTs With Duct Firing 550 MW | 550 | -0.8% | 1.1% | -0.6% | 1.1% | -0.8% | 1.5% |
| Biomass Fluidized Bed Boiler 50 MW | 50 | -0.3% | 0.7% | -0.2% | 0.7% | -0.2% | 1.1% |
| Geothermal Binary 30 MW | 30 | -2.8% | 2.0% | -2.4% | 2.4% | -2.4% | 4.2% |
| Geothermal Flash 30 MW | 30 | -0.8% | 4.0% | -0.5% | 4.4% | 0.8% | 7.5% |
| Solar Parabolic Trough W/O Storage 250 MW | 250 | -2.3% | 2.5% | -1.8% | 3.1% | -1.1% | 5.5% |
| Solar Parabolic Trough With Storage 250 MW | 250 | -2.5% | 2.3% | -2.0% | 2.9% | -1.6% | 5.0% |
| Solar Power Tower W/O Storage 100 MW | 100 | -2.3% | 2.5% | -1.9% | 3.0% | -1.3% | 5.3% |
| Solar Power Tower With Storage 100 MW 6 HRs | 100 | -2.4% | 2.4% | -1.9% | 2.9% | -1.4% | 5.2% |
| Solar Power Tower With Storage 100 MW 11 HRs | 100 | -2.6% | 2.2% | -2.1% | 2.7% | -1.8% | 4.7% |
| Solar Photovoltaic (Thin Film) 100 MW | 100 | -4.6% | 4.4% | -3.7% | 5.4% | -2.9% | 9.6% |
| Solar Photovoltaic (Single Axis) 100 MW | 100 | -2.9% | 2.3% | -2.4% | 2.9% | -2.1% | 5.1% |
| Solar Photovoltaic (Thin Film) 20 MW | 20 | -4.3% | 4.7% | -3.4% | 5.7% | -2.4% | 10.3% |
| Solar Photovoltaic (Single Axis) 20 MW | 20 | -2.7% | 2.5% | -2.2% | 3.1% | -1.7% | 5.5% |
| Wind - Class 3 100 MW | 100 | -1.7% | 1.3% | -1.7% | 1.2% | -1.9% | 2.0% |
| Wind - Class 4 100 MW | 100 | -1.7% | 1.3% | -1.7% | 1.2% | -1.9% | 2.0% |

Source: Energy Commission.

Financial Data Worksheet

Besides a results summary, the financial data worksheet has three information tables:

- The Financial Information table
- The Tax Information table
- Tax and Production Incentives table

Financial Information Table

Table 15 shows the Financial Information table for the 500 MW CC without duct-firing with merchant financing. These entities are explained using the numbers shown.

Table 15: Financial Information

| Financial Information | | |
|--|-------------------|-----------------|
| | Capital Structure | Cost of Capital |
| Equity Financed Share & Rate of Return | 33.0% | 13.25% |
| Developer Equity Financed Share & Financing Rate | 100.0% | 13.25% |
| Tax Equity Financed Share & Financing Rate | | |
| Debt Equity Share & Interest Rate | 67.0% | 4.52% |
| Discount Rate (WACC) | 6.17% | 4.53% |
| Inflation Rate From Base Yr. To Start Yr. | 2.31% | |
| Inflation Rate From Start Year Forward | 1.56% | |
| Debt Coverage Ratio - Average | 1.37 | |
| Debt Coverage Ratio - Minimum | 1.37 | |
| Loan/Debt Term (Years) | 10 | |
| Equipment Life (Years): | 30 | 12/31/2042 |
| Economic/Book Life (Years) | 30 | |
| Federal Tax Life (Years) | 20 | |
| State Tax Life (Years) | 20 | |

Source: Energy Commission.

Equity Financed Share and Rate of Return

The value shown as 33 percent is the percentage of capital raised that is financed through stock investments. The value shown as 13.25 percent is the interest paid to the investors.

Debt Share and Interest Rate

The value shown as 67 percent is the percentage of capital raised that is financed through bank loans, and the value shown as 4.52 percent is the average interest paid on the loan.

Discount Rate

The value shown as 6.17 percent is the discount rate and is assumed to be equal to the weighted average cost of capital (WACC). The WACC is adjusted for tax reduction in federal taxes for state taxes and is calculated as:

$$\text{WACC} = \text{Capital Structure Equity \%} * \text{Cost of Capital Equity \%} + \text{Capital Structure Debt Financed \%} * \text{Cost of Capital Debt Financed \%} * (1 - \text{Total Tax Rate})$$

Real Discount Rate

The value shown as 4.53 percent is the real discount rate, which is used in the overhaul calculation that is described in detail in the section on the overhaul worksheet. Real discount rate = $(1 + \text{Nom DR}) / (1 + \text{Inflation}) - 1$.

Inflation Rate from Base Year To Start Year

The equivalent average inflation rate for the period from the base year to the start year.

Inflation Rate from Start Year Forward

The equivalent average inflation rate for the period from the start year to the end of the book life.

Debt Service Coverage Ratio—Average

The debt service coverage ratio (DSCR) is equal to the ratio of expected cash flow to debt service. As the amount of debt on a project increases (or the cost of the debt increases), the DSCR decreases. On a forecast basis, lenders typically look at both the average and minimum DSCRs. Average DSCR is the simple average of all the DSCRs of the book life.

Debt Service Coverage Ratio—Minimum

The Minimum DSCR is the minimum observed value during the book life.

The rest of these terms are self-explanatory and will not be explained further herein.

Tax Information Table

Table 16 shows the tax information.

Table 16: Tax Information

| Tax Information | |
|---|--------|
| Federal Tax = | 35.0% |
| CA State Tax = | 8.84% |
| Total Tax Rate = | 40.7% |
| CA Avg. Ad Valorem Tax = | 1.10% |
| Municipal in-lieu payment of property taxes | Y |
| Sales & Use Tax Rate (CA Average) = | 7.94% |
| Proportion of Installation Costs Subject to Sales & Use Tax | 60.00% |

Source: Energy Commission.

State and federal taxes are common to merchant and IOU power plants but not to POU plants, which are exempt from both taxes. The total tax rate for merchant and IOUs is calculated as the total of the federal and state tax rates, allowing for the reduction in the federal rate for the state taxes—the idea being that the state taxes should not have to be paid twice.

Total Tax Rate = Federal Tax Rate (1-State Tax Rate) + State Tax Rate

Ad valorem taxes are calculated differently for all three developers. Merchant plants pay the shown rate based on installed cost. IOU plants pay the shown rate based on the rate base value, which depreciates over the lifetime of the power plant. POU power plants are not required to pay ad valorem, but generally make “in-lieu” payments.

The sales and use tax rate shown is a California average; however, rates vary throughout the state. Only the equipment portion of the installed costs are subject to sales tax, the labor portion is exempt. The number shown is an estimate.

Renewable Tax Benefits Information Table

Table 17 is the renewable tax benefits table. It works in conjunction with the financial worksheet to define deductions and tax credits on the income statement worksheet.

Table 17: Tax Benefits

| Tax & Production Incentives | | |
|---|----|-------|
| Eligible For BEITC | Y | |
| ITC Expiration | | |
| % Subject to ITC | | |
| Eligible For Geothermal Depletion Allowance | N | |
| Eligible For REPTC | Y | |
| PTC Expiration | | |
| Eligible For REPI | N | |
| REPI Expiration | | |
| Business Energy Investment Tax Credit (ITC) | N | |
| BETC Limit (\$) | | |
| BETC Depreciation Adjustment | | |
| BETC Limit (% Of Remaining Taxes) | | 100% |
| BETC Calculation | | \$0 |
| Geothermal Depletion Allowance | N | |
| Percentage Depletion | | |
| Limit (% Of Remaining Taxes) | | |
| Renewable Energy Production Tax Credit (REPTC) | N | |
| Duration | | |
| REPTC Base Year | | |
| REPTC In Start Year \$/kWh | | 0.000 |
| REPI Tier | | |
| REPI Tier I Proportion Paid | 0% | |
| REPI Tier II Proportion Paid | 0% | |
| REPI Duration | | |
| REPI Base Year | | |
| REPI In Start Year \$/kWh | | 0.000 |
| California Property Tax Solar Credit (Tax Exempt) | | |
| % Taxed at 25% of Full Value | | |
| California Solar Initiative \$/kWh | | |
| CSI Duration (years) | | |
| Solar installed capacity forecast at time of construction | 50 | MW |
| California Self-Generation Incentive Program | | /kW |

Source: Energy Commission.

Construction Costs Worksheet

This worksheet calculates the instant and installed costs for the base-year and start-year. It consists of five tables:

- Instant Capital Cost Table (Base Year \$)
- Capital Construction Costs by Year (Nominal \$)
- Summary of Capital Costs (\$/kW-yr)
- Environmental Impact Costs—ERCs
- Development Costs

Instant Capital Cost Table

Table 18 shows the instant capital cost panel for a 500 MW CC unit without duct-firing. All costs are for the start-year selected, but given in base year dollars. For the CC the start-year is 2013 and the base year is 2011.

There six categories of costs:

- Component Costs—generator, boilers, pipeline, and control system costs; all costs including construction costs, with the exception of the following costs and construction loan costs
- Land Costs—acquisition and preparation cost
- Development Costs—predevelopment, insurance, and commitment fee
- Permitting Costs—building, environmental, and ERC costs
- Interconnection Costs—transmission, fuel,water, and sewer costs
- Environmental Control Costs—air emission controls, and water treatment and cooling controls costs
- Total Component Costs - sum of costs shown as component costs; often a single line data entry so that it is duplicative of that value
- Input Override Capital Costs—this cell (shaded in turquoise) allows the user to insert a single value for the instant/installed cost and not provide the detailed components of the cost; not commonly used but useful for scenario work
- Default Total Capital Cost—either the sum of the above component costs and ancillary costs or, if a value is entered in the above item, that cost

Table 18: Instant Capital Costs

| Start-Year (2013) Instant Costs | In (2011 Dollars) |
|---|--------------------------|
| Financial Transaction Costs | 0.0% |
| Component Cost | |
| Total Overnight Cost | \$420,416,255 |
| Total Component Cost | \$420,416,255 |
| Land Costs | |
| Acreage/MW | |
| Acreage/Plant | 25.00 |
| Additional Occupied Acreage | |
| Total Acres | 25 |
| Cost Per Acre | \$70,000 |
| Acquisition Cost | \$1,750,000 |
| Land Prep Costs/Acre | |
| Total Land Prep Costs | \$0 |
| Total Land Costs | \$1,750,000 |
| Permitting Costs | |
| Local Building Permits | |
| Environmental Permits | \$6,900,000 |
| Emission Reduction Credits Costs | \$18,326,036 |
| Total Permitting Costs | \$25,226,036 |
| Interconnection Costs (Linears) | |
| All connection costs | \$30,445,500 |
| Transmission interconnection | |
| Fuel / water / sewer costs | |
| Total Interconnection Costs | \$30,445,500 |
| Air Emission Controls | |
| Installation Costs | \$0 |
| Total Air Emission Controls Costs | \$0 |
| Water Treatment & Cooling Controls | |
| Installation Costs | \$0 |
| Total Water Treatment & Cooling Controls Costs | \$0 |
| Total Environmental Controls Costs | \$0 |
| Total Component Cost | \$420,416,255 |
| INPUT OVERRIDE CAPITAL COST - Instant | |
| TOTAL CAPITAL COST - Instant | \$477,837,791 |

Source: Energy Commission.

Capital Construction Costs by Year Table

Table 19 is the panel that converts instant cost to installed cost. Each line in the column construction costs by year is in nominal dollars for the year shown and represents the total cost of the dollars expended in that year. The total cost is the sum of the money borrowed, including the Development Costs shown in **Table 19**, plus the loan interest allowance for funds used during construction (AFUDC rate). The final value (in red) is in start year in nominal dollars (2013 dollars). The AFUDC rate is assumed to be equal to the WACC for an IOU, and equal to debt rate for the merchant and POU plants.

The column entitled “Cumulative Construction Cost by Year” uses the following approximation formula based on the assumption that costs are distributed equally throughout the year:

Previous Years Costs (1+AFUDC) + % Costs current year X Instant Cost x Months/12

Where: Months/12 approximates the distributed costs over the year

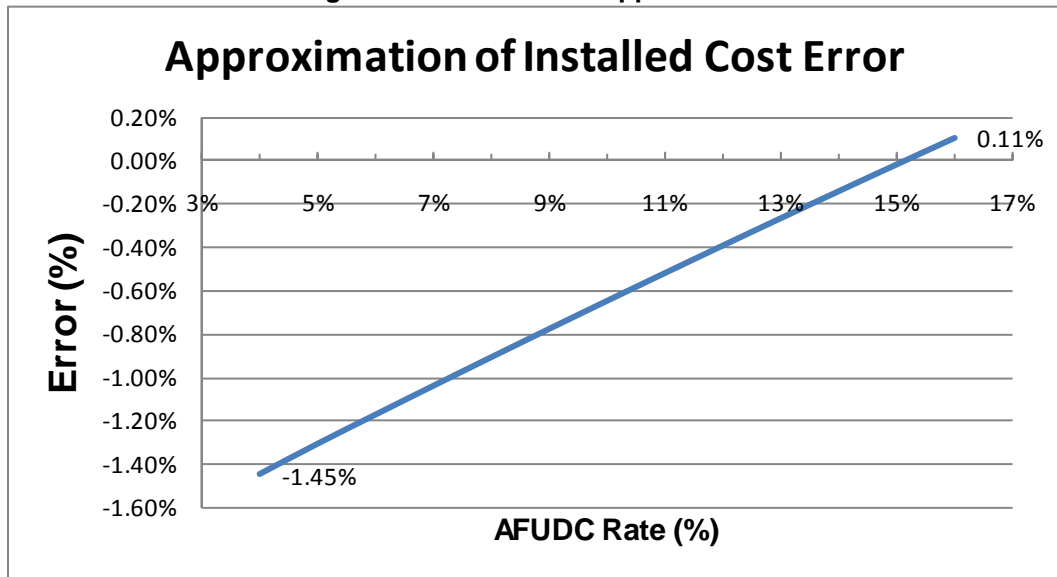
The error due to using this approximation is shown in **Figure 18**, which can be anywhere from understating the actual costs by 1.45 percent (POU financing for low cost case) to overstating the actual costs by 0.11 percent (merchant financing for high cost case). A model is by nature a series of approximations; this one is quite small and can be easily ignored considering that the assumption of equal regular costs is itself a much larger assumption.

Table 19: Converting Instant to Installed Cost

| Capital Construction Costs by Year (Nominal \$) | | | |
|--|----------------------------|---|------------------------------------|
| Escalation in Capital Costs | 0.00% | | |
| AFUDC Rate | 4.52% | | |
| Year | Cost % in Each Year | Cumulative Construction Costs by Year (Nominal \$) | Months in Construction Year |
| 2008 (-5) | 0% | \$0 | 0 |
| 2009 (-4) | 0% | \$0 | 0 |
| 2010 (-3) | 0% | \$0 | 0 |
| 2011 (-2) | 0% | \$0 | 0 |
| 2012 (-1) | 25% | \$128,512,768 | 12 |
| 2013 (0) | 75% | \$544,179,018 | 12 |

Source: Energy Commission.

Figure 18: Error Due to Approximation Formula



Source: Energy Commission.

Summary of Capital Costs

Table 20 converts the instant and installed costs in total dollars to instant and installed cost in \$/kW.

Table 20: Converting Instant to Installed Cost

| Start-Year Capital Costs (\$/kW) | | | |
|----------------------------------|---------|--|--|
| INPUT OVERRIDE | | | |
| Installed Cost (2013 Dollars) | | | |
| Instant Cost (2011 Dollars) | \$956 | Ratio of Installed to CapCostTotal | Ratio of Installed to ComponCost |
| Installed Cost (2011 Dollars) | \$1,040 | | |
| Instant Cost (2013 Dollars) | \$1,000 | | |
| Installed Cost (2013 Dollars) | \$1,088 | 1.088 | 1.237 |

Source: Energy Commission.

- Installed Cost (2013 dollars)—the turquoise block, input override, allows the user to override all the calculations and enter the installed cost in start-year nominal dollars directly
- Instant Cost (2011 dollars)—calculated by dividing the total instant costs by gross MW. This is a 2013 value in real 2011 dollars
- Installed Cost (2011 dollars)calculated by dividing the total installed cost by gross MW, and deflating the value back to 2011 dollars
- Instant Cost (2013 dollars)—calculated by inflating the above 2011 instant cost to 2013 dollars
- Installed Cost (2013 dollars)—calculated by dividing the total installed cost by gross MW

Development Costs

Table 21 shows 5.2 percent in development cost fees. These costs are included in the Table 20 calculations.

Table 21: Development Costs

| Development Costs | |
|------------------------------------|------------------------|
| Predevelopment Expenses | |
| Construction Insurance & Installat | 2.20% |
| Commitment Fee | |
| Debt Arrangement Fees | 3.00% |
| Total Development Costs | \$24,847,565.13 |

Source: Energy Commission.

Environmental Impact Costs

Table 22 shows the environmental impact cost table. These costs are for the specified start-year and are in base-year dollars.

Table 22: Environmental Impact Costs Table

| Air Emissions | Emissions | | Total Air Emission Costs - Year 2013 (2011dollars) | |
|---------------------------|-----------|-----------|--|---------------------|
| | (Lbs/MWh) | Tons/Yr | Fixed - Emission Reduction \$/Ton-Yr | (%) |
| NOx | 0.1105 | 131.56 | 64,182 | 8,443,840 |
| VOC/ROG | 0.0379 | 45.11 | 21,086 | 951,122 |
| CO | 0.3284 | 390.92 | 0 | - |
| CO2 | 848.8 | 1,010,369 | 0 | - |
| H2S | | 0.00 | 0 | - |
| CH4 | | | 0 | - |
| NH3 | | | 0 | - |
| SOx | 0.008 | 9.40 | 17,227 | 161,887 |
| PM10 | 0.0584 | 69.54 | 126,105 | 8,769,187 |
| Air Emission Costs | | | | \$18,326,036 |

Source: Energy Commission.

Operation and Maintenance Costs Worksheet

This worksheet has five tables:

- Fixed O&M Table
- Variable O&M Table
- Cost Factors Table
- Transmission Costs Table
- Maintenance Costs Table

Fixed O&M Cost, Table 23 , shows an illustrative table for fixed O&M, for the 500 MW CC. These are employee salaries, overhead, and equipment (including leasing), regulatory filings and other direct costs.

Table 23: Fixed O&M Costs Table

| FIXED O&M COSTS | | | |
|---|----------------|---------------------------|--------------|
| Employees | FTE | Hours/Year | Wages |
| Management Occupations | 2.26 | | \$118,920 |
| Production Occupations | 10.22 | 2,080 | \$33.08 |
| Installation, Maintenance and Repair Occupations | 3.17 | 2,080 | \$30.35 |
| Building and Grounds Cleaning and Maintenance Occupations | 0 | 2,080 | \$17.69 |
| Office and Administrative Support Occupations | 2.38 | 2,080 | \$21.36 |
| Protective Service Occupations | 2.18 | 2,080 | \$23.19 |
| Total W-2 Wages, adjusted to Base Year | \$1,382,970 | | |
| Overhead Multiplier | 1.634 | | |
| Annual Salary W/ Overhead (\$) | \$2,259,973 | | |
| Annual Salary W/ Overhead (\$/kW-Yr) | \$4.52 | | |
| Non-labor Fixed O&M including ODC \$/kW/Yr | \$28.17 | | |
| INPUT OVERRIDE | | | |
| Fixed O&M (\$/kW-Yr) | 32.69 | ← Overrides above values. | |
| Total Fixed O&M (\$/kW-Yr) | \$32.69 | | |

Source: Energy Commission.

Fixed O&M is calculated within the table, but it must also be entered as an override value in the plant type assumptions worksheet to facilitate the mechanism in the print table worksheet that summarizes the O&M costs. The same value would have been arrived at by allowing the table to calculate the value. That is, \$4.52 for salaries plus \$28.17 for non-labor costs equals \$32.69. This redundant table calculation is done for all gas-fired power plants. Other technologies rely solely on the override value being input on the plant type assumptions worksheet.

Table 24, Variable O&M Cost Table, is an illustrative example for the same CC technology without duct firing. As with the fixed O&M cost table, costs may be either entered in detail, or as an override value—shown here as 0.58 \$/MWh. In this case, the component costs do not add up to the override value because the component costs have not been updated. The override value is the result of the most recent effort to quantify this cost. The override value is input on the plant type assumptions worksheet and used for all technologies. The component costs are self-evident; however, clarification is provided below.

Table 24: Variable O&M Cost

| VARIABLE O&M COSTS | | |
|---|---------------|----------------------------|
| Water Supply Costs | | |
| Water Supply (\$/Acre Foot) | \$586 | |
| Consumption (AF/MWh) | 0.001 | |
| Water Supply Costs (\$/MWh) | 0.398 | |
| Make-Up Water (AF) | | |
| Reservoir Management | \$0 | |
| Total Annual Maintenance Costs(\$/MWh) | \$6.46 | |
| Total Environmental Costs (\$/MWh) | \$0.00 | |
| INPUT OVERRIDE | | |
| Variable O&M (\$/MWh) | 0.58 | <- Overrides above values. |
| Total Variable O&M (\$/MWh) | \$0.58 | |

Source: Energy Commission.

Water Supply Costs

Calculated as a function of the region. The cost per acre-foot is taken from the plant site air and water data worksheet. The total cost of water is then calculated as cost per acre-foot times the acre-foot consumption, which is taken from the technology assumptions worksheet, via a macro.

Total Annual Maintenance Costs

The sum of three maintenance cost types:

- Routine—periodic maintenance that is less than annual
- Scheduled—periodic maintenance that is both annual and greater than annual
- Unscheduled—maintenance that results from a forced outage

Total Environmental Costs

The sum of total annual environmental O&M costs and variable—reclaimed trading credits (RTC) and mitigation fees.

Total Annual Environmental Operation and Maintenance Costs

The sum of three components:

- Total Annual Air Emissions Costs (Excluding Capital)—annual costs of replacement, consumables, and labor
- Total Annual Water Treatment Costs (Excluding Capital)—annual costs of replacement, consumables, and labor
- Total Annual Solid Waste Disposal Costs—collection, hauling, landfill tipping, and dumping

Cost Factors Table

Table 25 shows the cost factors that are used in the income statement worksheet:

- Real Labor Escalation (percentage)—estimates the real escalation of labor costs for use in calculating fixed O&M costs in the income statement worksheet

- Real O&M Escalation (percentage)—estimates the real escalation of O&M costs for use in calculating variable O&M in the income statement worksheet
- Insurance Costs (percentage)—estimates the cost of insurance used in the fixed cost calculation in the income statement worksheet

Table 25: Cost Factors Table

| Cost Factors - Used in Income Statement | | |
|---|--------|------------------|
| Labor Escalation Cost (Above Inflation) | 0.500% | (Fixed Costs) |
| O&M Escalation (Above Inflation) | 0.500% | (Variable Costs) |
| Insurance | 0.600% | (Fixed Costs) |

Source: Energy Commission.

Income Statement Worksheets

This section describes the income statement worksheets in detail. It defines the components and explains the mechanics, including a detailed description of the algorithms. Due to the immense size of this worksheet, figures are not shown. There are two types of income statements in the COG Model:

- Income Cash-Flow for Merchant plants
- Income Revenue Requirement for IOU and POU plants

These two sheets are similar and differ only with regard to how the equity payments are made to stock holders. Both are described here in general and the differences in mechanics are explained later.

The income statement worksheets calculate the final levelized costs calculated by the COG Model. These costs are broken out into the following categories:

- Levelized Fixed Costs
 - Capital & Financing (Construction Costs)
 - Insurance
 - Ad Valorem (Property Taxes)
 - Fixed O&M Costs
 - Corporate Taxes (Federal & State)
- Levelized Variable Costs
 - Fuel Costs
 - Variable O&M Costs

In all cases, yearly values must be calculated for the book life of the power plant, which are then converted to present values so that the levelized cost can be calculated.

Levelized Fixed Costs

Capital and Financing

The capital and financing costs cover the capital cost of the equipment and facilities plus the cost of constructing and financing the power plant. The capital cost is calculated in the Construction Cost worksheet, first as instant cost, which covers the cost of the equipment and all related facilities including licensing, and then as installed cost, which covers the construction costs. These costs are calculated both in the base year and the in-service year as \$/kW and are used in the Income Statement Worksheet to calculate the financing costs (debt and equity).

Insurance

Insurance is calculated using a percentage rate that is set at 1.1 percent. This percentage rate is designated as “InsurancePct” and comes from the physical data worksheet, which gets data from the plant type assumptions worksheet.

For an IOU, the percentage rate is applied against the book value, and since the book value decreases over the life of the calculation, the insurance payments are higher in the early years and lower in the later years.

For a merchant and municipal plant, the percentage rate is applied against the installed cost per kW. The installed cost per kW is calculated on the construction cost worksheet as a base year value. This product is then escalated first to the start year using historical inflation and then throughout the book life of the project using the forward inflation.

Ad Valorem

Ad valorem, which is the traditional name for property taxes, is calculated differently for municipal, IOU, and merchant plants. For a municipal plant, the property taxes are zero by definition. For an IOU, it is calculated as the ad valorem tax rate (financial data worksheet) times the depreciated value of the plant. For a merchant plant, it is calculated as ad valorem Tax rate times the installed cost per kilowatt. Also for merchant-owned plants installed cost is escalated at the Proposition 13 limit =2 percent.

Fixed Operation and Maintenance

The base year value is calculated in the O&M Costs worksheet. The yearly values are then escalated to the start year using historical inflation and then throughout the book life using the forward inflation rate. Both use the same normal inflation, but each has its own real escalation factor: Fixed O&M uses labor escalation rate whereas variable O&M uses O&M escalation rate. These factors can be found on the O&M worksheet on the cost factors table, and originate on the general assumptions worksheet.

Corporate Taxes

Corporate taxes are state and federal taxes. They are individually but similarly calculated as a tax rate (financial data worksheet) times the quantity before tax income (operating income) minus deductions, this quantity must then be reduced by the tax credits—similar to

personal taxes. The deductions for state are interest on the loan and depreciation. It is the same for the federal taxes except that there is also the standard deduction for state taxes (so that state taxes are not paid twice, similar to personal taxes). All technologies are eligible for the Tax Deduction for Manufacturing Activities (TDMA). Geothermal plants are eligible for Geothermal Depletion Allowance (GDA). There are also tax credits available, such as Business Expense Tax Credit (BETC), Renewable Energy Production Tax Credit (REPTC), and Renewable Energy Production Incentive (REPI). Conceptually this seems straight forward but is complicated by the subtleties in the calculation of the Operating Income as explained below.

Levelized Variable Costs

Fuel Cost

Fuel cost is calculated only for fossil-fueled generators, nuclear, gasified coal, and biomass generators. Geothermal fuel cost is considered to be captured in the purchase price. The number of Btu used is calculated on a yearly basis as the heat rate (physical data worksheet) times the energy generated (same sheet). These yearly values would be the same except for the yearly heat rate degradation value (same sheet). The fuel cost is calculated as the number of Btu times the fuel price (fuel price forecasts worksheet).

There is a subtlety to the calculation of fuel use as it relates to the heat rate for gas-fired units. The model shows the fuel use for startups. This is informational only. It is not calculated and then added to the running heat rate. The startup heat rate is calculated and then subtracted from the total average heat rate to estimate the running heat rate. The heat rate is calculated from a regression of actual fuel use (Btu) used and energy generated (GWh), from the Energy Commission's QFER database.

Variable O&M

This is calculated similarly to fixed O&M above.

Cost of Generation Model Mechanics and Definitions

All the above cost categories are calculated in a straightforward manner except for the fact that corporate taxes are based in part on revenue. At the same time, the revenue is a function of corporate taxes. The COG Model solves for this by assuming that the revenue will be enough to cover all expenses, including loan and equity payments. This is accomplished by the COG Model's algorithms, which are explained below. To understand these algorithms, it is necessary to understand standard financial accounting terms as well as the relationship between them.

Operating Expenses—Operating

Expenses are all the above items except capital and financing costs and corporate taxes. It includes insurance, ad valorem, fixed and variable O&M, and fuel cost.

Revenue Requirement

This is the total income for the plant that must be sufficient to pay all costs: operating expenses, taxes, debt, and equity (stock holders). Another way to say this is that the revenue requirement is equal to the operating expenses plus the operating income. As explained above, this is determined as the sum of all the costs it must cover. That is, the revenue requirement must be equal to the levelized cost of generation.

Operating Income/Before Tax Income

A key element in the income statement is the calculation of the operating income. The operating income, which is the same thing as the before tax income, is equal to the revenue requirement minus the operating expenses. That is, it is the amount of money that the developer must have on hand after paying operating expenses to pay the taxes, retire the debt, and pay the stock holders (equity payments).

After Tax Income

After tax income is the income remaining after state and federal taxes are paid. This residual amount must be sufficient to retire the debt and pay the stock holders. It is equal to the operating income minus the tax payments.

Modeling Algorithms

The algorithms for the Income Statement Worksheet depend on whether the accounting is done on a revenue requirement or cash-flow basis. Revenue requirement accounting is common to IOUs and POUs—except POUs have neither taxes nor equity payments to account for. Cash-flow is most common to merchant plants. The difference between using revenue requirement or cash-flow is small for technologies with little or no tax benefits but can be quite large where tax benefits are applicable.

The complexity of these algorithms grows out of the fact that the revenue requirement is undefined in the general case and is therefore set to an amount that is just adequate to meet all expenses. This leads to the dilemma that the state and federal taxes cannot be calculated before the revenue is known, and the revenue requirement cannot be known until the state and federal taxes are calculated. Mathematically this is stated as:

$$R = \text{Function}(T_s \ \& \ T_f)$$

$$T_s \ \& \ T_f = \text{Function}(R)$$

Where R = Revenue Requirement

And $T_s \ \& \ T_f$ = State and Federal Taxes

This leads to the need for simultaneous equations that the COG Model can solve in circular references are avoided.

Revenue (R) must equal the sum of:

- Operating Expenses (OE):

- Fixed O&M costs
- Insurance and ad valorem (Property Taxes)
- Fuel cost
- Variable O&M
- State and federal taxes (T_s & T_f):
- Cost of debt (**Dt**) and equity (**Eq**)

$$\text{Equation 1: } R = OE + T_s + T_f + Dt + Eq$$

Taxable income is calculated separately for state and federal as:

- Taxable state income: before tax income (BTI)—state deductions (D_s)
- Taxable federal income: before tax income (BTI)—federal deductions (D_f)
- State deductions (D_s): state depreciation and interest on debt
- Federal deductions (D_f): federal depreciation, interest on debt, manufacturing activities (TDMA), geothermal depletion allowance (GDA)⁶
- Federal tax credits (C_f): BETC, REPTC & REPI
- Taxes are equal to tax rates times taxable income - tax credits (C)

$$\text{Equation 2: Federal Taxes: } T_f = t_f(BTI - D_f - T_s) - C_f$$

$$\text{Equation 3: State Taxes: } T_s = t_s(BTI - D_s) - C_s$$

There are no state tax credits.

The calculation of debt and equity can then be calculated as follows:

- Debt: the principle and interest portions must be calculated separately in order to provide the interest portion available for deduction on taxes.
 - Principle portion of debt calculated as Excel function PPMT
 - Interest portion of debt calculated as Excel function IPMT
 - Total debt calculated as SUM of PPMT and IPMT, but could have been calculated using the Excel function of PMT
- Equity calculation depends on type of revenue accounting
- Income revenue requirement for IOUs and POUs
- Income cash flow for merchant plants

Up to this point, there was still no difference between revenue requirement and cash flow. The difference between revenue requirement and cash flow is in how the equity payments are calculated. This affects only the fixed costs and in only two categories: capital and financing cost and corporate taxes (state and federal taxes).

⁶ GDA is ignored in the model as developers cannot use both GDA and REPTC. Using REPTC is more advantageous as default.

Revenue Requirement

In the revenue requirement income sheet, equity and debt payments are known—unlike the revenue cash flow sheet where the equity payments must be determined through simultaneous equations. This makes the calculations much more straight forward:

- Federal taxes: $T_f = t_f(BTI - D_f) - C_f = t_f(ATI + T_f - D_f) - C_f$

$$\text{Solving for } T_f: T_f = \frac{t_f(ATI - D_f) - C_f}{(1 - t_f)}$$

- State taxes: $T_s = t_s(BTI - D_s) - C_s = t_s(ATI + T_f + T_s - D_s) - C_s$

$$\text{Solving for } T_s: T_s = \frac{t_s(ATI + T_f - D_s) - C_s}{(1 - t_s)}$$

Note that the federal taxes look like the conventional calculation except that BTI is replaced by ATI and there is a $(1 - t_f)$ factor in the denominator. The state taxes are similar but notice the T_f value in the equation.

Cash-Flow

In the cash-flow income statement, the equity payments must be calculated using a minimization method, where a uniform stream of revenue payments (increasing or decreasing depending on contractual terms) is created while meeting the net present value of the equity payments over the economic life of the plant necessary to compensate the investors. Because the revenue level is a function of after-tax income plus taxes, and taxes are a function of the before-tax income, and the revenue amount must be a relatively level stream over the years, the model must solve for how equity income will vary among years to achieve the net present value target for equity return over the entire period, not one year at a time. In other words, unlike the revenue requirement method, the equity return in any year is not independent of the return in other years.

The Southern California Edison Company (SCE) Cost of Generation Model, which was further developed by E3 for use in the California Public Utilities Committee Market Price Referent, uses the Excel© Goal Seek function to change the projected revenue by changing the contract price so that the net present value of the equity return equals the target equity return after paying taxes. The Black & Veatch (B&V) Cost of Generation Model, used for the Energy Commission's Renewable Energy Transmission studies, uses the Excel table function that makes a linear estimate of how the net revenue function changes with the contract price paid. Both Excel functions produce similar results because the Goal Seek function uses a similar linear estimate method duplicated in the table function setup. Staff elected to use the table function similar to the B&V Cost of Generation model because it allows for automatic adjustment of the target contract price without having to run goal seek separately for each change in technology, assumptions, or scenarios. However, staff found that the change in net revenue was not a linear function over the full range of contract prices due to the more complex representation of expenses and taxes in the Energy

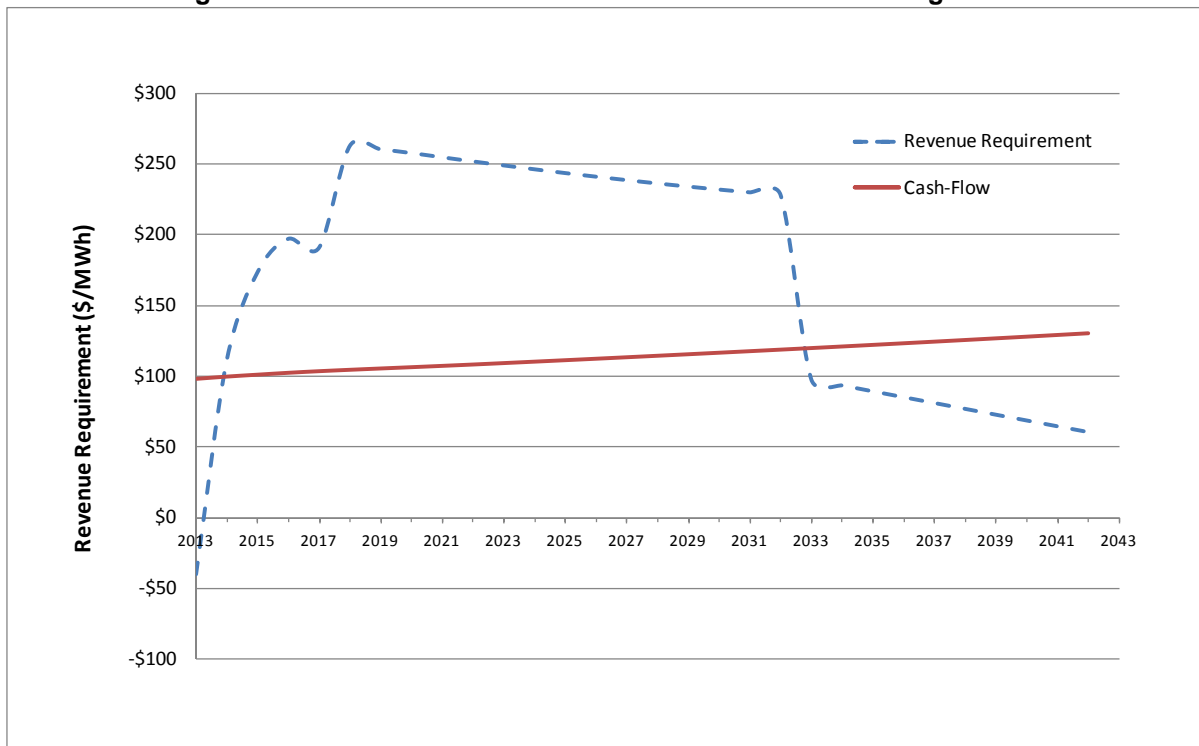
Commission COG Model compared to the B&V RETI model. Instead a piecewise linear function was created using the Excel table function to capture the nonlinear relationship.⁷

For two reasons, the revenue requirements and cash flow may not arrive at the same value. The first reason is since the revenue requirement calculates the annual revenue separately for each year, changes in the relationships among years do not affect the revenue requirement within an individual year. The annual revenue requirement is a function of the weighted average cost of capital that equals the discount rate used to calculate the levelized cost of capital. For the cash flow method, cost components are discounted by three discount rates—the interest rate for debt, the rate of return for equity for the profit, and the weighted average of these two for expenses. The resulting net present value of each of these streams of values is a nonlinear function of each discount rate. The sum of nonlinear functions does not equal the nonlinear function of the sums. The former is the cash flow method, the latter is the revenue requirement function. The second reason is that tax incentives typically are applied to nominal values asset values and income streams. Moving the net present value of income from one period to another can have secondary tax consequences that then change the revenue target, which in turn changes the tax looping back and forth. The difference between the cash flow and revenue requirement results is not Typically large, but it becomes significant when large tax incentives are applicable to a technology.

Figure 19 illustrates the difference in the annual costs of cash-flow vs. revenue requirements for a 100 MW solar PV single axis technology, going online in the year 2013.

⁷ The table function calculation can be found on the income-cash flow worksheet in the COG Model, starting at cell B190. Since it works in discrete increments, it is using discrete points, the distance between can only be approximated as a straight line.

Figure 19: Annual Revenue Stream for 100 MW Solar PV Single Axis



Source: Energy Commission.

The two curves show the annual total costs for the two methods. The revenue requirement is irregular due to tax credits. The drop of in 2033 reflects the end of the debt payments. The cash-flow is more regular due to the table function, which works to the benefit of a merchant plant by taking the entire benefit of the tax credit in the first year, but paying the equity back on a slowly increasing scale.

Overhaul Worksheet

The overhaul worksheet is used only where component variable O&M costs are calculated. This was designed to work of the gas-fired technologies only. At present, this is not being used for gas-fired, or any, technologies. All the overhaul worksheet requires special treatment due to the inclusion of irregular maintenance intervals. In addition, the COG Model has a special requirement of having to develop base year values for use in the income statement worksheet. This section describes how these irregular maintenance costs are converted into the necessary base year values for use in the income statement worksheet.

The income statement worksheets each have an item called variable O&M, which requires base year dollars as a starting point for its calculations. The base year is the most recent year for which there is known data, and is therefore the initial point of calculation. Variable O&M has several component costs that are calculated in the O&M costs worksheet, and then combined together to get the total base year cost. Four of these components are not readily

available in Base Year dollars and require a special—somewhat subtle—treatment to be converted to base year dollars:

- Major Overhaul Costs
- Minor Overhauls Costs
- Air Emission Equipment Replacement Costs
- Water Treatment & Cooling Equipment Costs

The income statement worksheet takes the base year value and escalates it to cover real escalation (O&M escalation and labor escalation) and nominal (historical and forward) Inflation. It then calculates the present values of all yearly values, and finally calculates the levelized cost.

The overhaul worksheet first calculates the PV of the irregular maintenance, and then calculates a payment value (PMT), which is the necessary base year value.

$$\text{PMT}((1+\text{RealDiscountRate})/(1+\text{OMEscalation})-1, \text{BookLife}, \text{SUM}(E5:AE5) / (1+\text{DiscountRate})) * ((1+\text{InflationRate}) * (1+\text{OMEscalation})) / ((1+\text{HistInflationRate}) * (1+\text{OMEscalation}))^{(\text{StartYr}-\text{BaseYr})}$$

For descriptive purposes, this can be represented as:

$$\text{PMT}(\text{InterestRate}, \text{BookLife}, \text{PV}) / ((1+\text{HistInflationRate}) * (1+\text{OMEscalation}))^{(\text{StartYr}-\text{BaseYr})}$$

The division of term in the second line which is the inflation from base year to start year, $((1+\text{HistInflationRate}) * (1+\text{OMEscalation}))^{(\text{StartYr}-\text{BaseYr})}$. That is, since multiplying the base year value by this term inflates the value to the start year, dividing by this same value deflates a start year value back to the base year. The explanation of the necessary “InterestRate” is more subtle but it essentially takes the payment value back to the start year. That is, it has to undo the inflation and real escalation so that these values can be reconstructed in the income statement worksheet. It does this by first reducing the discount rate by the inflation rate, which gives us real discount rate, which is the real portion of the discount rate. Mathematically, the real discount rate is constructed as follows:

$$(1+\text{RealDiscountRate}) = (1+\text{DiscountRate}) / (1+\text{Inflation})$$

$$\text{RealDiscountRate} = [(1+\text{DiscountRate}) / (1+\text{Inflation})] - 1$$

Similarly the Real Escalation must be removed:

$$(1+\text{InterestRate}) = (1+\text{RealDiscountRate}) / (1+\text{OMEscalation})$$

$$\text{InterestRate} = [(1+\text{RealDiscountRate}) / (1+\text{OMEscalation})] - 1$$

This final manipulation will be recognized by some as calculating the asset rental value (Carlton and Perloff 1990), but definitions are of less importance here than understanding the intent of the manipulations. One way to help understand this is to realize that if the present value calculated on the overhaul worksheet could be moved to the present value

cell on the income statement, this manipulation would not be necessary. However, it would create an inconsistency in the format and would be complicated by several components of variable O&M that must be first be added together and then divided by annual energy for this to be complete.

The following is a more rigorous treatment of this same issue, which will be helpful to those that are comfortable with mathematics. The procedure first shows the mechanism of the income statement worksheet and then explains how the overhaul worksheet prepares the present values of the overhaul worksheet to create the necessary base year value.

In the income statement worksheet, the model goes through the following steps. The inflation is first calculated from the base year to the start year (in service year), using HistInflation for general inflation and Real Escalation to cover the real component of escalation. The total inflation of variable O&M is therefore calculated as:

$$((1+\text{HistInflationRate})*(1+\text{RealEscalation}))^{(\text{StartYr} - \text{BaseYr})}$$

It is then inflated year by year from the start year to the end of the period (typically 20 years, such that the exponent assumes values from 0 to 19):

$$(1+\text{InflationRate})*(1+\text{RealEscalation})^{(\text{Year} - \text{StartYr})}$$

For a base year value designated herein as base year variable O&M, each yearly value can therefore be calculated as:

$$\text{BaseYearVarO\&M} * [(1+\text{HistInflationRate})*(1+\text{RealEscalation})]^{(\text{StartYr} - \text{BaseYr})} * [(1+\text{InflationRate})*(1+\text{RealEscalation})]^{(\text{Year} - \text{StartYr})}$$

If the following substitutions are made, this formula can be simplified for illustration:

$$a = \text{BaseYearVarO\&M}$$

$$b = [(1+\text{HistInflationRate})*(1+\text{RealEscalation})]^{(\text{StartYr} - \text{BaseYr})}$$

$$c = [(1+\text{InflationRate})*(1+\text{RealEscalation})]$$

Using the distributive law, the annual costs can then be represented by the formula:

$$\text{Variable O\&M} = a * b * (c^0 + c^1 + c^2 + c^3 + c^4 + c^5 + \dots + c^{n-1} + c^n)$$

And the present value can be calculated using discount rate "D" as:

$$\begin{aligned} & \text{Present Value of } a * b * (c^0 + c^1 + c^2 + c^3 + c^4 + c^5 + \dots + c^{n-1} + c^n) \\ & = a * b * \text{Present Value of } (c^0 + c^1 + c^2 + c^3 + c^4 + c^5 + \dots + c^{n-1} + c^n) \\ & = a * b * \{ [c^0 / (1+D)^0 + c^1 / (1+D)^1 + c^2 / (1+D)^2 + c^3 / (1+D)^3 + c^4 / (1+D)^4 + c^5 / (1+D)^5 + \dots + c^{n-1} / (1+D)^{n-1} + c^n / (1+D)^n] / (1+D) \} \\ & = a * b * \{ [c / (1+D)]^0 + [c / (1+D)]^1 + [c / (1+D)]^2 + [c / (1+D)]^3 + [c / (1+D)]^4 + [c / (1+D)]^5 + \dots + [c / (1+D)]^{n-1} + [c / (1+D)]^n \} / (1+D) \end{aligned}$$

This is mathematically equivalent to: $(1-v^n)/(1/v-1)$, where $v = c/(1+D)$

$$= a*b* \{1 - [c/(1+D)]^n / 1/ [c/(1+D)] -1\}$$

$$= a*b* \{1 - [c/(1+D)]^n / [(1+D)/c] -1\}$$

If $c/(1+D)$ can be replaced with a term called *equivdiscountrate* = i , then

$$(1+i) = (1+D)/c = (1+D)/ ((1+InflationRate)*(1+RealEscalation))$$

$$i = [(1+D)/ [(1+InflationRate)*(1+RealEscalation)]] -1$$

Present value = $a*b* \{1 - [c/(1+D)]^n / [(1+D)/c] -1\}$

$$= a*b* \{1 - [1/(1+i)]^n / [(i -1)]\}$$

Solving for a gives us the inverse of PV, which is a levelized PMT:

$$a = 1/b * 1/ \{1 - [1/(1+i)]^n / [(i -1)]\} = 1/b * 1/ PV = 1/b * PMT$$

Or in Excel terminology:

$$a = 1/b * PMT(i, Life, PV)$$

$$\text{BaseYearVarO\&M} = 1/[(1 + \text{HistInflationRate}) * (1 + \text{RealEscalation})]^{(\text{StartYr} - \text{BaseYr})} * \text{PMT}(i, \text{Life}, \text{PV})$$

The PV of irregular costs is calculated in the overhauls worksheet, and then the payment value is also calculated, using traditional PV techniques. This PV is then calculated using this formula, giving the cost in start year dollars. And finally, that value is divided by the escalation, $[(1 + \text{HistInflationRate}) * (1 + \text{RealEscalation})]^{(\text{StartYr} - \text{BaseYr})}$, to bring the value back to base year dollars. **Table 26** illustrates how this works.

Table 26: Sample Overhaul Calculation

| Nominal Discount Rate | | 10% | | | |
|-------------------------|---|-----------------|---|---|--|
| Inflation Rate | | 2% | | | |
| Real Escalation Rate | | 0.5% | | | |
| Effective Discount Rate | | 7.31% | | | |
| Year | Nominal Cash Flows w/Real Escalation Rate | | Levelized Cash Flows with Nominal Discount Rate | Levelized Cash Flows with Effective Discount Rate | LCFs w/RDR Escalated at Inflation + Real |
| 1 | 0.00 | | \$20.49 | \$17.28 | 17.28 |
| 2 | 0.00 | | \$20.49 | \$17.28 | 17.72 |
| 3 | 0.00 | | \$20.49 | \$17.28 | 18.16 |
| 4 | 0.00 | | \$20.49 | \$17.28 | 18.62 |
| 5 | 110.42 | 75.42 | \$20.49 | \$17.28 | 19.08 |
| 6 | 0.00 | | \$20.49 | \$17.28 | 19.56 |
| 7 | 0.00 | | \$20.49 | \$17.28 | 20.05 |
| 8 | 0.00 | | \$20.49 | \$17.28 | 20.56 |
| 9 | 0.00 | | \$20.49 | \$17.28 | 21.07 |
| 10 | 125.00 | 53.01 | \$20.49 | \$17.28 | 21.60 |
| 11 | 0.00 | | \$20.49 | \$17.28 | 22.15 |
| 12 | 0.00 | | \$20.49 | \$17.28 | 22.70 |
| 13 | 0.00 | | \$20.49 | \$17.28 | 23.27 |
| 14 | 0.00 | | \$20.49 | \$17.28 | 23.86 |
| 15 | 141.49 | 37.26 | \$20.49 | \$17.28 | 24.45 |
| 16 | 0.00 | | \$20.49 | \$17.28 | 25.07 |
| 17 | 0.00 | | \$20.49 | \$17.28 | 25.70 |
| 18 | 0.00 | | \$20.49 | \$17.28 | 26.34 |
| 19 | 0.00 | | \$20.49 | \$17.28 | 27.00 |
| 20 | 160.16 | 26.19 | \$20.49 | \$17.28 | 27.68 |
| NPV-Nom | \$174.43 | \$174.43 | \$174.43 | | \$174.43 |

Source: Energy Commission.

GLOSSARY

| Acronym | Definition |
|-------------------|--|
| \$/MMBtu | Dollars per million British thermal units |
| \$/MWh | Dollars per megawatt hour |
| MMBtu | Million British thermal units |
| ACAT | Analytica Cost of Generation Analysis Tool |
| AFUDC | Allowance for funds used during construction |
| ARRA | American Recovery and Reinvestment Act |
| BETC | Business expense tax credit |
| B&V | Black and Veatch |
| BOE | Board of Equalization |
| BTI | Before tax income |
| Btu | British thermal unit |
| Btu/kWh | British thermal unit per kilowatt-hour |
| California ISO | California Independent System Operator |
| CC | Combined cycle |
| CF | Capacity factor |
| COG Model | Cost of Generation Model |
| CSI | California Solar Initiative |
| CT | Combustion turbine (simple-cycle) |
| DCR | Debt coverage ratio |
| DSCR | Debt service coverage ratio |
| EAF | Equivalent availability factor |
| EBITDA | Earnings before interest, taxes, depreciation and amortization |
| EFOR | Equivalent forced outage rate |
| Energy Commission | California Energy Commission |
| ERC | Emission reduction credit |

| | |
|-----------------|---|
| ESOF | equivalent scheduled outage factor |
| FO | Forced outage |
| FOH | Forced outage hours |
| FOR | Forced outage rate |
| FTE | Full time equivalent |
| GADS | Generating Availability Data Service |
| GDA | Geothermal depletion limit |
| GW/GWh | gigawatt/gigawatt-hour |
| IEPR | Integrated Energy Policy Report |
| ITC | Investment Tax Credit |
| IOU | Investor-owned utility |
| kW/kWh | Kilowatt/kilowatt-hour |
| LC | levelized cost |
| LCOE | Levelized cost of energy |
| MACRS | Modified accelerated cost recovery system |
| MMBtu | million British thermal units |
| MOH | maintenance outage hours |
| MOR | maintenance outage rate |
| MW/MWh | megawatt/megawatt-hour |
| NCF | Net capacity factor |
| NO _x | Nitrides of oxygen |
| NPV | net present value |
| O&M | Operation and maintenance |
| PM10 | particles of 10 micrometers |
| PMT | Payment function |
| POH | Planned outage hours |
| POU | Publicly owned utility |
| PTA | Plant type assumptions |

| | |
|-----------------|---|
| PV | Photovoltaic |
| QFER | Quarterly Fuels and Energy Report |
| RECLAIM | Regional Clean Air Incentives Market |
| REPI | Renewable energy production incentive |
| REPTC | Renewable energy production tax credit |
| RTC | RECLAIM trading credits |
| SCAQMD | South Coast Air Quality Management District |
| SCE | Southern California Edison Company |
| SCR | Selective catalytic reduction |
| SGIP | Self-Generation Incentive Program |
| SH | Service hours |
| SOF | Scheduled outage factor |
| SOH | Scheduled outage hours |
| SOR | scheduled outage rate |
| SO _x | Sulfides of oxygen |
| TDMA | Tax deduction for manufacturing activities |
| UO | unplanned outage |
| UOH | unplanned outage hours |
| WACC | Weighted average cost of capital |

APPENDIX A: Definitions

Accumulated Depreciation: A running total of the year by year depreciation.

$$\text{Accumulated Depreciation} = \text{Book Value/Rate Base} * \text{Sum (Cumulative Yearly Book Depreciation) through Year N}$$

Acquisition Costs: Total costs for acquiring the necessary land for the plant and dedicated infrastructure.

$$\text{Acquisition Costs} = \text{Total Acres} * \text{Cost Per Acre}$$

Ad Valorem Tax: Also called property taxes. In California, property tax is assessed differently based on ownership. Utility-owned plants pay based on the value assessed by the BOE, and are set to the net depreciated book value. The value reflects the market value of the asset, but may not increase in value at a rate faster than 2 percent per annum per Proposition 13. Municipal-owned plants are exempted from paying property taxes, but may pay a negotiated in-lieu fee. The calculation of ad valorem for any one year is:

If owner type = merchant, then:

$$\text{Ad Valorem Tax} = \text{Ad Valorem Tax Rate} * \text{Installed Cost (Year Calculation Is Done)} * \text{BOE Property Tax Depreciation Factor (1+ Forward Inflation Rate)}^{(\text{Year Calculation Is Done} - \text{Start Yr})}$$

If owner type = IOU, then:

$$\text{Ad Valorem Tax} = \text{Ad Valorem Tax Rate} * \text{Book Value/Rate Base}$$

Air Control Annual Consumables-Catalyst: The cost of the consumable inputs (for example, ammonia) used in the air emission control device, usually selective catalytic reduction (SCR).

Air Emissions Control Technology Capital Costs: It is the capital cost of purchasing and installing the air emissions control technology equipment.

$$\text{Air Emissions Control Technology Capital Costs} = \text{Air Emissions Control Installation Cost} * \text{Gross Capacity} * 1000^8$$

AFUDC Rate: The cost of the construction loan, insurance and taxes that is associated with construction period of the power plant. These costs are not recovered immediately through rates or sales, but are accumulated and recovered later along with the total capital investment. The AFUDC rate is usually set equal to the weighted average cost of capital (WACC), which is the case in the Energy Commission's COG Model.

⁸ Gross capacity is in MW while the calculation is done in kW, making it necessary to convert by multiplying by 1000.

Annual Average Heat Rate (Btu/kWh): A measure of the efficiency of power plants. It is the amount of heat supplied in Btu's to generate 1 kWh of electricity. The smaller the heat rate the greater the efficiency. The efficiency of a power plant can be calculated as 3,413 divided by the heat rate (3,413 being the conversion factor to convert 1 kWh into Btu). The model uses heat rates based on actual performance, primarily as reported in the Energy Commission's QFER database. The reported annual fuel use (Btu) is divided by the annual energy (GWh) to get the annual heat rate. Therefore, heat rate variability and start-up fuel are automatically captured.

Annual Average Operating Heat Rate Net of Startups (Btu/kWh): Although this quantity does not affect the calculation of heat rate in the COG Model as explained above, it is provided as a convenience to the COG Model user, in order to estimate the effect of start-ups on the average annual heat rate. Typically, this is small enough as to not be important, but sometimes it becomes significant for a combustion turbine. In any case, the effect is reported in the model should the user want to be cognizant of it.

$$\text{Average Operating Heat Rate (Net Of Startups)} = \{(\text{Annual Average Heat Rate} * \text{Gross Capacity} / 1000) * \text{Operational (Service) Hours/Year} - \text{Start Up Fuel Use} * \text{Number Of Annual Starts}\} / \text{Gross Capacity} / 1000 * \text{Operational (Service) Hours/Year}$$

Annual Capacity Degradation Rate (Percent): The annual average rate at which a power plant loses peak generating capacity, averaged over the expected lifetime of the facility. The rate typically is small initially, but accelerates with age. This degradation can be offset by regular maintenance and overhauls. Although this rate varies over time, it is captured in the COG Model as a constant value throughout the life of the project. This is explained in more detail in Chapter 4 of the User's Guide.

Annual Fuel Use: The estimated annual fuel used by a power plant.

$$\text{Annual Fuel Use} = \text{Gross Capacity} / (1 + \text{Annual Capacity Degradation Rate})^{(\text{Year Calculation Is Done} - \text{Start Yr})} * \text{Average Percentage Output} * \text{Operating Hours/Year} / 1000 * \text{Average Operating Heat Rate} * (1 + \text{Heat Rate Degradation})^{(\text{Year Calculation Is Done} - \text{Start Yr})} + \text{Start-Up Fuel} * \text{Number Of Annual Starts}.$$

Annual Heat Rate Degradation: The annual increase in heat rate due to aging of the equipment is called heat rate degradation, but is offset by periodic maintenance—in the COG Model, the heat rate degradation number reflects the effect of the maintenance. Similar to the capacity degradation rate, the heat rate degradation rate is given as a singular average value. In the COG Model, this makes heat rate and fuel consumption increase over time, but does not affect output (MW), which remains constant—unless annual capacity degradation rate is entered in the COG Model.

Annual Salary with Overhead (\$): Annual salaries with overhead included. This is calculated in the COG Model by applying an overhead multiplier.

**Annual Salary w/ Overhead = {(Manager Full Time Equivalent (FTE)*
 Manager Salary + Plant Operator FTE * Plant Operator Hrs*
 Plant Operator Wage + Mechanics FTE * Mechanics Hrs * Mechanics Wage +
 Laborer FTE * Laborer Hrs * Laborer Wage + Support Staff FTE * Support Staff
 Hrs * Support Staff Wage)}* Overhead Multiplier**

Annualized Air Emissions Replacement Cost: The levelized cost of replacing air emission equipment. This is calculated first as actual yearly costs, then as a present value of those annual costs, and then finally as a levelized cost. In Excel terminology the calculation is:

**Annualized Air Emissions Replacement Cost = -PMT((1+ Real Discount
 Rate)/(1+OM Escalation)-1, Book Life, Sum(Intermittent Values)/
 (1+Discount Rate))* ((1+ Inflation Rate)* (1+OM Escalation))/((1+ Historical
 Inflation Rate)* (1+OM Escalation) ^ (StartYr-BaseYr)**

Annualized Water Cooling Replacement Cost: The levelized cost of replacing water cooling equipment. This is calculated first as actual yearly costs, then as a present value of those annual costs, and then finally as a levelized cost. In Excel terminology the calculation is:

**Annualized Air Emissions Replacement Cost = -PMT((1+ Real Discount
 Rate)/(1+OM Escalation)-1, Book Life, Sum(Intermittent Values)/
 (1+Discount Rate))* ((1+ Inflation Rate)* (1+OM Escalation))/((1+ Historical
 Inflation Rate)* (1+OM Escalation) ^ (StartYr-BaseYr)**

Asset Rental Price: An alternative way of valuing property. For example, if a company owned a truck, it could value the truck at the same price it could rent the truck for. This is explained in detail in Attachment B.

**Asset Rental Rate = Foregone Interest + Depreciation – Price Appreciation
 (or Depreciation)**

Average Annual Energy (GWh): This is calculated at three points: power plant low side of the uplift transformer, the high side of the uplift transformer and at the point of interconnection. This would be calculated as the capacity at each point times the operating hours times the average percent output except for the fact that this is the point in the COG Model where the effect of capacity degradation is captured. This is a complex calculation that is described in Chapter 4.

Average Percentage Output (Percent): Expected average available capacity during hours of operation (for example, 100 percent for a CC unit, 66 percent for a wind unit, 100 percent for a combustion turbine even if unit is operated only during peak summer hours), including any periods of derated operation in this factor.

Base Year: The most recent year for which the power plant data is available. Data for subsequent years is scaled from the base year using inflation rates.

Before Tax Income (Operating Income or [EBITDA]): This means “Earnings Before Interest, Taxes, Depreciation and Amortization,” but after all product/service, sales and overhead

costs are accounted for. It is also sometimes referred to as operational cash flow or operating income and it serves as a sort of starting point to solve the problem that the models does not inherently compute revenues because no “market price” is provided. Instead, the revenues are computed on the assumption that the revenues just equal those required to make the power plant financially viable under the assumed terms included in the model. It is solved as the simultaneous solution of equations and is explained within the User’s Guide. The formula in all its complexity is:

$$\text{Before Tax Income} = \text{After Tax Return On Debt \& Equity} + \text{State Taxes} + \text{Federal Taxes}$$

Also,

$$\text{Before Tax Income} = \text{Revenue} - \text{Operating Expenses}$$

Book Depreciation: An accounting procedure that allocates the cost of a fixed asset over the estimated useful life of the asset. It is the amount of expense charged against earnings by a company to write off the cost of a plant or machine over its useful life, giving consideration to wear and tear, obsolescence, and salvage value. If the expense is assumed to be incurred in equal amounts in each business period over the life of the asset, the depreciation method used for state taxes is straight line, and for federal taxes is modified accelerated cost recovery system (MACRS) tables.

$$\text{If Owner Type} = \text{"Merchant"}, \text{Book Depreciation} = 0$$

$$\text{If Owner Type} = \text{"IOU, Municipal"},$$

$$\text{Book Depreciation} = \text{Installed Cost (Start Year)} * \text{Book Depreciation Rate}$$

Book Depreciation Rate: The rate at which book depreciation is collected. In the COG Model, this is modified accelerated cost recovery system for federal and 150 percent of declining balance for state.

Book Life (Years): The projected life of an asset upon which a depreciation schedule is based. From an accounting perspective, this is the period over which investors expect to recover their investments plus returns. The actual life of the power plant will likely exceed this by a number of years.

Book Value: A business' historical cost of assets less liabilities. The book value of a stock is determined from a company's records by adding all assets (generally excluding such intangibles as goodwill), then deducting all debts and other liabilities, plus the liquidation price of any preferred stock issued. The sum arrived at is divided by the number of common shares outstanding and the result is the book value per common share. Book value of the assets of a company may have little or no significant relationship to market value. Tangible book value is different than book Value in that it deducts from asset value intangible assets, which are assets that are not hard (for example, goodwill, patents, capitalized start-up expenses and deferred financing costs). Economic book value allows for

a book value analysis that adjusts the assets to their market value. This valuation allows valuation of goodwill, real estate, inventories, and other assets at their market value.

Business Energy Tax Credit (BETC): A tax credit that is available to businesses and is applicable to merchant facilities only. See Appendix D.

Byproduct Revenues and Costs: Incidental income and costs associated with the power plant operation.

Capacity and Energy: Capacity is the ability to generate, store or receive Energy. This can be more vividly illustrated in terms of a specific example: an electrical generation power plant, where capacity (MW) is the ability to generate energy (GWh). If a power plant with a Capacity of 1000 MW operates for one hour, it will generate 1000 MWh of Energy—or 1 GWh. If it operates for one year (8,760 hours) at this capacity, it will produce 8,760 GWh of energy.

Capital & Financing (Construction) Costs (\$/kW-yr): The costs of purchasing, installing and financing a power plant. It includes the cost of equipment and land purchases, any ERCs, the construction loan and the sales taxes. All these costs are ultimately financed through debt and equity, such that these costs can be defined as follows:

Capital & Financing Costs = Debt Payment +Equity Recovery

However, in the COG Model, this cost quantity is calculated in the construction cost worksheet as the sum of the instant costs converted to annual construction costs that are adjusted for inflation and sales taxes.

Capital Construction Costs By Year (\$): The construction takes place over a period of years. So the capital construction costs for each year is the construction cost in the year along with the financing (AFUDC) associated with the construction loan for that year. The Excel formula is calculated as:

Capital Construction Costs By Year = Cost %/Year * Total Instant Capital Cost * IF(Months In Construction Year>0,(1+AFUDCRate/(24/ Months In Construction Year)),0)+ Cumulative Construction Costs By Year *(1+ AFUDC Rate),Total Instant Capital Cost)*((1+Historical Inflation Rate)*(1+Capital Cost Escalation Rate))^(Start Yr-Base Yr)

Capital Structure (Percent): This refers to the percentage of financing a power plant that is raised through equity as opposed to debt financing. Also, it's the permanent long-term financing of a company. Capital structure normally includes common and preferred stock, long-term debt and retained earnings. It does not include accounts payable or short-term debt.

Table A-1 is a summary of the present (2013 IEPR) capital cost data. For an IOU ownership, 52 percent of the capital is raised through equity and 48 percent through debt; the cost of equity is 11.85 percent, and the cost of debt is 5.40 percent.

Table A-1: Capital Cost Data

| Owner Type | Capital Structure | | Cost Of Capital | |
|-----------------------|-------------------|------|-----------------|-----------|
| | Equity | Debt | Equity Rate | Debt Rate |
| Merchant Fossil | 60.0% | 40% | 14.47% | 7.49% |
| Merchant Alternatives | 40.0% | 60% | 14.47% | 7.49% |
| Default IOU | 52.0% | 48% | 11.85% | 5.40% |
| Default POU | 0% | 100% | 11.85% | 5.40% |

Source: Energy Commission.

It should be apparent that either the percentage debt or percentage equity defines the other:

$$\text{Debt Financed (\%)} = 1 - \text{Equity (\%)}$$

Commitment Fee: A fee paid to a debt financing entity to ensure that project financing is committed to a project.

Construction Insurance: The cost of insurance to cover the period during the construction of a power plant.

Consumption (Acre Foot/MWh): The water used by the power plant per MWh.

Corporate Taxes (W/Credits) (\$/KW-yr): The taxes, deductions and investment credits associated with the power plant. These are state and federal taxes. See state taxes and federal taxes.

$$\text{Corporate Taxes} = \text{State Taxes} + \text{Federal Taxes}$$

Cost of Capital (Percent): The cost to a company of acquiring funds to finance the company's capital investments and operations. In general, there are two components, debt and equity. See capital structure, debt and equity.

Debt (\$): Financing the cost of the power plant. Also, raising money through selling bonds, notes, or mortgages or borrowing directly from financial institutions. Borrowed money is paid in full, usually in installments, with interest. A lender incurs risk and charges a corresponding rate of interest based on that risk.

Debt Coverage Ratio (DCR): The debt coverage ratio is the ratio of the company's operating profit to its expenses. This ratio indicates its ability to cover its expenses using its profits from operations. If it is low, the company might encounter difficulties meeting financial expenses out of its current activities. A high ratio indicates relatively low expenses and a good financial position.

A financial institution often will require before issuing debt that a financial prospectus show that the average DCR over the life of a loan will exceed a certain ratio, for example, 1.8 is common and a minimum DCR for any single year of a smaller ratio, for example, 1.5 is preferred.

Debt Payment: Periodic repayment of debt or a loan.

$$\text{Debt Payment} = \text{Principal} + \text{Interest}$$

Debt Rate (Percent): The interest charged on a loan or debt issued.

Depreciation: Depreciation is the accounting of the deterioration of the physical and functional utility of a fixed asset due to usage and time. **Depreciation** can be explained in **economic** or **accounting** terms. The accounting depreciation methods are of two types: Book and tax depreciation.

Discount Rate (Percent): Used to calculate the present value of future cash flows as well as the levelized cost. The discount rate reflects not only the time value of money, but also the riskiness associated with the cash flows. The discount rate is calculated within the COG Model as the WACC.

Economic Life (Years): For accounting and depreciation, this term is synonymous with book life. More generally, this is the expected life of an asset over which it will be economically productive.

Effective Operating Capacity (MW): Adjustment to Net Capacity that accounts for intermittent operational limits, for example, wind variation, hydro drought conditions, that reduce the expected plant capacity in any moment.

$$\text{Effective Operating Capacity} = \text{Net Capacity} * \text{Average Percent Output}$$

Emission Reduction Credits (ERCs): Permit offsets purchases from other regional emitters to compensate for added emissions from a new power plant. The ERCs differ by air quality regulation district (for example, Southern California Air Management District [SCAQMD]) and constituent pollutant (for example, NO_x, SO_x, PM 10, and so forth.) The ERCs are for a one-time purchase so the costs are spread over the book life of the asset similar to other capital expenditures.

Equipment Life (Years): The estimated life of equipment. In the COG Model this is used to determine depreciation and the frequency of overhauls.

Equity (\$): The net worth of a firm or corporation. Equity can be both common stock and preferred stock. Equity can come from selling of stock or other assets. The ownership shares of a corporation authorized by its articles of incorporation, including preferred and common stock. This is also known as capital stock or equity holdings and is expressed as ownership or percentage of ownership in a company or items of value (that is, assets and liabilities). These funds are acquired for construction and operation with repayment terms subject to income performance by the asset.

Equity Rate (Percent): The rate that is used to calculate the cost of using a company's equity holdings to finance the power plant—as opposed to using long-term debt. This percentage in simplest terms is what it costs to pay the stock holders the necessary dividends plus expected capital appreciation, but it all includes all assets that can be used to raise money.

Equivalent Availability Factor (EAF) (Percent): A measure of a unit's reliability. In simplest terms, it can be thought of as the percent of time that a power plant is available to generate power. That is, those hours when it is not on scheduled maintenance or down due to a forced outage. In the COG Model, it is defined as

$$A = (1-FOR) (1-SOF)$$

Where: FOR = Forced Outage Rate

SOF = Scheduled Outage Factor

The above formula is simplistic as it applies only to the case where a unit is either completely on or completely off—never derated due to partial equipment failure. Although this formula is used in the model, it really implies the more general case where derates exist, and availability should be calculated as:

$$A = (1-EFOR) (1-ESOF)$$

Where: EFOR = Equivalent Forced Outage Rate

ESOF = Equivalent Scheduled Outage Factor

Equivalent Forced Outage Rate (EFOR): A power plant's rate if failure accounting for partial derates. FOR is simplistic in that it applies only to the cases where the power plant is either available at its full power or has completely failed. In actuality a power plant can be available at partial power; that is, derated. For this more complex case, the term EFOR is used to capture the effect of these derates.

$$EFOR = \frac{\text{Forced Outage Hours} + \text{Equivalent Forced Derated Hours}}{\text{Forced Outage Hours} + \text{Service Hours} + \text{Equivalent Forced Derated Hours during Reserve Shutdowns (RS) Only}} \times 100\%$$

Equivalent Scheduled Outage Factor (ESOF): A measure of a power plant's failure rate accounting for derates. Similar to EFOR, it accounts for scheduled maintenance that is performed while the plant is derated. Although annual maintenance, planned outage hours (POH) is typically performed with the power plant turned off, maintenance outages can be done during partial derates.

$$ESOF = (SOH+ESDH)/PH;$$

Where: SOH = POH+MOH

ESDH = EPDH+-EMDH

Escalation In Capital Costs (Percent): The cost of the power plant generally changes over time. This percentage value is the annual change in these costs. This escalation is used in the COG Model to translate known base year costs to the actual start year costs.

Federal Tax Depreciation: The depreciation allowance on capital assets provided in the Internal Revenue Code. The allowance is computed using the MACRS tax schedule.

Federal Tax Life (Years): The book life of the asset for purposes of computing federal tax depreciation and related tax items.

Federal Taxes: Taxes that the owner must pay to the federal government. These are calculated as follow (since POU's don't pay taxes, the REPI is taken out as it cannot be used):

If Owner Type = "Muni", Federal Taxes = -REPI
If Owner Type = "IOU, Merchant", Federal Taxes = Federal Tax Rate*(After Tax Return On Debt & Equity) -(Debt Interest+ Federal Tax Depreciation +TDMA+GDA--(BETC+REPTC)/ (1-Federal Tax Rate))

Final Planned Operating Hours/Year: Expected Hours in a year the unit is planned to be operating. The expected hours of operation per year minus the SOH.

Final Planned Operating Hours/Year = Minimum (Planned Percent of Year Operational*8760, 8760 - Scheduled Outage Hours.)

Financial Transaction Costs: Fees collected by financial institutions related to issuing debt and raising equity to finance construction and operation of a power plant.

Fixed Costs (\$/KW-yr or \$/MWh): These are the costs for power plants that occur regardless of whether it operates or not. Fixed costs include capital cost (including the financing costs), insurance, ad valorem and corporate taxes (federal and state taxes). In other words, all costs except variable O&M and fuel costs.

Fixed Costs = Capital & Financing (Construction) Costs + Insurance + Ad Valorem Costs + Fixed O&M Costs + Corporate Taxes (W/Credits)

Fixed O&M Costs (\$/KW-yr): These are the costs of operating and maintaining the power plant that occur regardless of how much the power plant operates. What is included in this category is not always consistent from one assessment to the other but always includes labor costs and the associated overhead. The most common characterization, and the one used in the Energy Commission's COG Model, includes both staffing costs and non-staffing costs. Non-staffing costs are comprised of equipment, regulatory filings, and other miscellaneous direct costs. The Commission's survey of costs found that for simple cycle and CC units, these costs (\$/kW-yr) vary with the size of the plant. The formula used in the COG Model to calculate the first year values of fixed O&M is:

Fixed O&M/kW-Yr (Base Year) = Annual Salary w/ Overhead+ Non Labor Fixed O&M/ Gross Capacity (MW)*1000

The annual cost is calculated in the COG Model as:

$$\text{Fixed O\& M Costs (Year Calculation Is Done)} = (\text{Fixed O\&M/kW-Yr} \\ (\text{Base Year}) * ((1 + \text{Historical Inflation Rate}) * (1 + \text{Labor Escalation}))^{(\text{Start Yr} - \text{Base Yr})} * \\ ((1 + \text{Forward Inflation Rate}) * (1 + \text{Labor Escalation}))^{(\text{Year Calculation Is Done} - \text{Start Yr})}$$

Fixed Operating Expense: The sum of fixed O&M costs, ad valorem, and insurance.

$$\text{Fixed Operating Expense} = \text{Fixed O\&M Costs} + \text{Ad Valorem} + \text{Insurance}$$

Forced Outage Hours: Forced outages (FO) are those outages where a plant must be taken out of service for unplanned repairs. The hours where a unit spends in this condition is called forced outage hours.

Forced Outage Rate (FOR): The power plant's rate of failure. This calculation ignores the period during reserve shutdown (economic shutdown) as this period tells us nothing about how the plant performs—because it was not asked to perform we cannot know how it would have done. It is based solely on when it is called upon. The GADS formula for this is:

$$\text{FOR} = \text{FOH} / (\text{FOH} + \text{SH})$$

Where: FOH = Forced Outage Hours (Hours Of Failed Operation)

SH = Service Hours (Hours Of Successful Operation)

Forward Inflation Rate: It is the average annual inflation rate from the start year to the year calculation is done.

Fuel Consumption/Hour (MMBtu/Hr): The amount of fuel used by a power plant in Millions of Btu per hour.

$$\text{Fuel Consumption/Hour} = \{ \text{Gross Capacity (MW)} * \text{Average Percentage} \\ \text{Output} * \text{Annual Average Operating Heat Rate (Net of Start Up)} \} / 1000$$

Fuel Cost (\$/kW-Yr): Fuel Cost is the cost of electricity. It is calculated as the fuel price (dollars per million British thermal units [\$/MMBtu]) times the fuel use (million British thermal units [MMBtu]). Fuel use is calculated as gross MW times the operating hours times the heat rate (Btu/kWh). This is the major component of variable cost for fuel-intensive sources for which fuel is purchased, for example, fossil fuels.

$$\text{Fuel Costs (\$/kW-Yr)} = \frac{\text{Fuel Price (\$/MMBtu)} * \text{Annual Fuel Use (MMBtu)}}{\text{Gross Capacity (MW)} * 1000}$$

Full-Time Equivalent: Equivalent number of employees working full time.

Geothermal Depletion Allowance: A federal tax deduction provided for exhausting or depleting (“depreciating”) a geothermal reserve. This allowance is similar to the oil depletion allowance in the federal tax code.

$$\text{GDA} = \text{Minimum (Geothermal Depletion Limit} * \text{Tax On Return On Equity,} \\ \text{Geothermal Depletion Percent} * \text{Equity Recovery)}$$

Geothermal Resource Royalty Payment: When a company or individual enters into a geothermal lease with the United States Government, that company or individual agrees to pay a share (royalty) of the value of production to the United States.

$$\text{Geothermal Resource Royalty Payment} = 0.1 * \text{Return On Equity} * \text{Gross Capacity (MW)} * 1000$$

Gross Capacity (MW): The capacity of the power plant without parasitic load. That is, the capacity of the power plant before it has to provide power to serve the load associated with the power plant. See net capacity.

Historical Inflation Rate: It is the average annual inflation rate from the base year to the start year.

Inflation: The rate of change in a price index (for example, the Consumer Price Index) over a certain period that reflects a general increase in all prices so that the relative costs of different goods and services remain essentially the same. Alternatively, inflation reflects the percentage reduction in the purchasing power of a dollar over a specified period, for example, a year.

Installed Costs (In-Service Costs) (Dollars per kilowatt [\$ /kW]): The total cost of building a power plant. It includes not only the instant costs, but also the costs associated with the fact that it takes time to build a power plant. Thus, it includes a building loan, insurance, sales tax and property taxes—as well as the costs associated with escalation of costs during construction.

$$\text{Installed Cost (Base Year)} = \frac{\text{Total Construction Cost} * (1 + \text{CA Sales Tax})}{\text{Gross Capacity} * 1000}$$

$$\text{Installed Cost (Start Year)} = \frac{\text{Total Construction Cost} * (1 + \text{CA Sales Tax})}{(\text{Gross Capacity} * 1000) * (1 + \text{Historical Inflation Rate})^{\text{Start Yr} - \text{BaseYr}}}$$

Instant Costs (\$/kW): The cost of a purchasing and building a power plant assuming that it could be built in an instant. In fact, the building may take several years and incur additional costs. See Installed Cost

$$\text{Instant Cost (Base Year)} = \frac{\text{Total Instant Capital Cost}}{(\text{Gross Capacity} * 1000)}$$

$$\text{Instant Cost (Start Year)} = \frac{\text{Total Instant Capital Cost}}{[(\text{Gross Capacity} * 1000) * (1 + \text{Historical Inflation Rate})^{\text{Start Yr} - \text{BaseYr}}]}$$

Insurance: The cost of insuring the project which is paid as an annual premium.

If Owner Type = "IOU", Insurance = Insurance % * Book Value Or Rate Base

If Owner Type = "Merchant, Municipal", Insurance = Insurance % * Installed Cost (Year Calculation Is Done) * (1 + Forward Inflation Rate)^(Year Calculation Is Done - Start Yr)

Start Yr)

Labor Escalation: The escalation in plant operation labor costs above the escalation in general economy-wide price levels or inflation.

Land Preparing Costs/Acre: The costs of preparing land before construction through clearing and infrastructure installation on a per acre basis.

Landfill Tipping Fees: The fees paid to dispose of solid waste.

Levelized Cost (LC): Levelized Cost is the singular most important objective of this model. It is the annual payment (same value all years) that is equivalent to all the costs incurred in the construction and operation of the power plant. If the Net Present Value of all these payments is calculated as NPV, then

$$LC = \frac{[NPV * I * (1+i)^n]}{[(1+i)^n - 1]}.$$

The corresponding Excel formula is PMT (discount rate, book life, PV).

For a series of unequal payments, the Excel formula is PMT (discount rate, book life, NPV (discount rate, yearly value 1, yearly value 2, ...,yearly value n).

This is the same principle used in determining the mortgage payment on a house. A mortgage payment is a levelized payment to repay the lump-sum loan amount, which is the equivalent of the net present value of the loan. For example, if the house cost \$100,000, the expected term of the payment is 20 years and the interest rate of 5 percent, the annual house payment is \$8,024.26.

Load Center: Load center is the physical location where the power is being received under contract. The model must account for the losses between the where the power is generated, at the generator busbar (low side of uplift transformer), and where it is delivered at the load center.

Load Center Delivered Capacity: The available generating capacity delivered to the typical retail meter or “load center.” It is the capacity net of the power plant uplift transformer losses and the transmission losses.

$$\text{Load Center Delivered Capacity} = \text{Net Capacity} * (1 - \text{Transmission Losses}) * (1 - \text{Ancillary Services \& Reserves})$$

Loan/Debt Term (Years): Length of loan for that portion of the financing of the power plant that is financed through long term debt. See cost of capital and capital structure.

MACRS Tax Tables: Federal tax depreciation tables reflecting the MACRS. These depreciation methods apply to assets placed in service after 1986; less favorable than the earlier Accelerated Cost Recovery System system.

Major Overhaul: These are repairs that are extensive and are done less than annually, such as every 2.5 years. The calculation of these costs on an annual basis is quite complicated and is not shown here, but can be found in the overhaul section of this User’s Guide.

Minor Overhaul: These are typically annual repairs that are much less extensive than major overhauls.

Major Overhaul Replacement Costs: It is the cost of replacing equipment associated with major overhauls.

Makeup Water: Water which is supplied (as to a steam boiler or cooling tower) to compensate for losses by evaporation and leakage.

Net (After-Tax) Income: Income after taxes are taken into account.

Net (After -Tax) Income = Before Tax Income - Taxes

Net Capacity (MW): The capacity as it leaves the power plant structure, net of losses and providing station service. This is the usable power that leaves the power plant at the busbar and is sent over the transmission lines.

Net Capacity = Gross Capacity (1 - Plant Site Uses & Losses %)

Net Capacity Factor (NCF): This term is equivalent to CF. CF is calculated as the energy generated by the plant divided by the energy that could have been generated had it operated at full output for the entire year (8,760 hours). This denominator is an unlikely value as it assumes that there is no maintenance, no forced outages and no reserve shutdown during the entire year. In the COG Model it becomes equivalent to Availability for a base load unit because the COG Model assumes that there are no reserve shutdown hours. But for a CT, solar or wind unit, it will be less.

For a SC unit (CT), it will be less as the operational hours are constrained to reflect its intended low CF - this is done using plant percent of year operational. For a solar or wind unit, NCF will be less due to its operating capacity being derated to reflect the variability of its fuel source (sunlight for solar and adequate wind for wind units)

Net Capacity Factor (NCF) = Operational Hrs/Yr*Effective Operating Capacity (MW)/(8760*Net Capacity (MW))

Net Revenues (\$): The revenue that is left after all costs are deducted.

Net Revenues = Revenues - Costs

Number of Annual Starts: The number of times a power plant is started during the year.

O&M Escalation: The real portion of O&M inflation. That is, the escalation in plant operation and maintenance non-labor costs above or below the escalation in general economy-wide price levels.

Operational (Service) Hours/Year: Number of hours in a year the power plant operates.

Operational Hours/Year = Planned Operating Hours/Year - Forced Outage Hours

Overhaul Labor (Hours): The labor costs incurred in scheduled maintenance overhauls

Overhauls: Costs incurred for large-scale scheduled maintenance. See **major overhauls** and **minor overhauls**.

Overhead Multiplier: This multiplier is applied to the total labor salaries incurred to account for the added non-salary costs such as benefits and employment taxes.

Period Hours (PH): Generating and data systems terminology for the number of hours in a year.

Planned Percent of Year Operational: This factor is derived from either historical data or modeling results, both external to this model. Expected percent of year that unit is planned to be operating. This percentage times the average output during operation will be the primary factors determining annual generation. For example: a solar plant may be operational 100 percent of the year with a 25 percent average output, a peaking unit will have a 100 percent average output with a 10 percent planned percent of year operational.

Plant Scheduling Costs: Costs incurred to sell and schedule power plant output to the grid, for example, for day-ahead and real-time sales to the California ISO. This cost can vary by technology and load-following type (for example, peaking vs. baseload). This cost measure is appropriate for comparison to distributed generation and demand side management measures when computing costs at the load center.

Plant Losses (Percent): The percentage of onsite load required to operate a power plant. This load typically includes pumps, lighting and other local services.

Predevelopment Expenses: Expenses incurred by the project developer in preparation for design, financing and construction.

Present Value (PV): The value of periodic payments discounted to the base year. Mathematically, each year's value is multiplied by $PV = 1 / (1+i)^n$, where **i** is interest (the value of money) and **n** is the number of years of discount. If the series of values are identical, the formula becomes $PV = [(1 - (1+i)^n)] / i$. Excel has a present value function called **PV**. If the series of payments are different, $PV = 1 / (1+i)^n$ must be multiplied against each yearly value - the corresponding Excel Formula is NPV.

Rate Base: The value of a regulated public utility and its operations as defined by its regulators and on which the company is allowed to earn a particular rate of return.

Book Value Or Rate Base = Installed Cost (Start Year) - Accumulated Depreciation.

Real Discount Rate: The real discount rate reflects the nominal or apparent discount net of inflation. The real discount rate is applied to present value calculations in economics, finance and engineering that use constant or real dollars. The proper discount rate to use depends on whether the benefits and costs are measured in real or nominal terms. This term is used in the model to facilitate the calculation of overhaul costs, air emissions, water treatment and cooling equipment replacement costs.

- A real discount rate that has been adjusted to eliminate the effect of expected inflation should be used to discount constant-dollar or real benefits and costs. A real

discount rate can be approximated by subtracting expected inflation from a nominal interest rate.

- A nominal discount rate that reflects expected inflation should be used to discount nominal benefits and costs. Market interest rates are nominal interest rates in this sense.

The real discount rate is calculated in the COG Model as follows:

$$\text{Real Discount Rate} = (1 + \text{Nominal Discount Rate}) / (1 + \text{Inflation Rate}) - 1$$

Renewable Energy Production Incentive (REPI): A tax credit that is available to Municipal facilities only. See Appendix D

Renewable Energy Production Tax Credit (REPTC): A tax credit that is available to merchant and IOU facilities. See Appendix D

Reservoir Management: Costs incurred in royalties and other fees for managing a geothermal steam or hot water reservoir or water rights associated with a reservoir or lake used to provide water to a hydropower plant.

Return Of Equity: A term used only by IOUs, to break the more commonly used term "Return on Equity" into two parts return on equity and return of equity. Return of equity is that portion that will exactly repay the sum of the initial investment without any profit.

If Owner Type = "IOU", Return Of Equity = Equity Rate % * Book Depreciation

Return On Equity: In general, this term represents the portion of financing that is done through issuing stock as opposed to debt financing. For IOUs, it has a subtler meaning: It is the annual time value of money lent above and beyond the return of equity. In other words, this is the profit that shareholders accrue from having made the initial investment. It is calculated differently based on ownership.

If Owner Type = "IOU", Return On Equity = Equity Rate % * Book Value Or Rate Base * Equity Percent

If Owner Type = "Merchant", Return On Equity = -PMT((Equity Rate, Book Life, Equity Percent * Installed Cost Per kW)

Return On Ratebase: Measured as net income as a percentage of net book value (total assets minus intangible assets and liabilities). This is performance measure for a regulated utility.

$$\text{Return On Ratebase} = \frac{\text{Return On Equity}}{(\text{Equity \%} * \text{Book Value Or Rate Base})}$$

Revenue Requirement: The revenues required to cover the total cost of constructing and operating a power plant: Operating expenses, taxes and debt and equity payments. These types of utilities typically have posted prices prescribed by a regulatory commission or government council that do not directly reflect market forces.

$$\text{Revenue Requirement} = \text{After Tax Return On Debt \& Equity} + \text{Total Operating Expense} + \text{Total Taxes}$$

Reclaim Trading Credits (RTCs) & Mitigation Fees: SCAQMD RTCs and per pound of emission or per hour of operation mitigation fees paid to local air quality regulation districts. RTCs are bought and sold among several hundred industrial facilities to allow variations in NOx and SOx emissions from initial permitted levels. Mitigation fees are typically charged when a facility or power plant exceeds its permitted level of operation or emissions in a set period of time (for example, 12 months or a calendar year).

Scheduled Outage Factor (SOF): The ratio of SOH to the hours in a year (8,760). That is, the percentage of the year that a plant is on scheduled maintenance. If a plant has 876 hours of maintenance, then its SOF is 10 percent. This is more or less synonymous with the more commonly used modeling term Maintenance Outage Rate (MOR).

$$\text{SOF} = \text{SOH/PH} \quad \text{Where: SOH} = \text{POH} + \text{MOH}$$

Scheduled Outage Hours: GADS define scheduled outages (SO) as the combination of planned outages and maintenance outages (MO). For those purposes when Maintenance Outage Hours (MOH) are still included with the FO, the term Unplanned Outages (UO) is applicable.

$$\begin{aligned} \text{Scheduled Outage (SO)} &= \text{PO} + \text{Maintenance Outage (MO)} \\ \text{Unplanned Outage (UO)} &= \text{FO} + \text{Maintenance Outage (MO)} \\ \text{Planned Outage (PO)} &= \text{Yearly Planned Maintenance} \end{aligned}$$

The corresponding hours for Scheduled Outages (SO) and UO are Scheduled Outage Hours (SOH) and Unplanned Outage Hours (UOH). These are illustrated below, relative to POH, MOH and Forced Outage Hours (FOH).

$$\begin{aligned} \text{SOH} &= \text{POH} + \text{MOH} \\ \text{UOH} &= \text{FOH} + \text{MOH} \end{aligned}$$

In the COG Model, only SOH are used.

Scheduler Costs: Costs for bidding and scheduling a power plant in the electricity market, for example, delivery of power to the California ISO).

Service Hours (SH): This is GADS terminology. In our model we use operational (service) hours/year.

Spark Spread: This is a measure of the financial viability of a power plant. In its common form, it compares the energy payments available to a power plant against its cost of operation (fuel cost times heat rate)—and is sometimes expressed as a heat rate difference. In the COG Model, it is characterized in a less common manner where the revenue is compared against the cost of operation in the form of a heat rate difference. It is calculated of heat rate differences:

$$\text{Spark Spread} = [\text{Revenue} - (\text{Fuel Cost}) * (\text{Heat Rate})] * \text{Gross MW/Annual Energy}$$

Start Year: The year that the power plant is in service and available to generate power for the grid. This is also the first year in the present value and levelized cost calculations. In the model start year is synonymous with in service year.

Start-Up Fuel Use (MMBtu/Start): Prior to a thermal power plant being connected to the power system, it consumes fuel—most of which is associated with warming the power plant components, for example, boilers. This warm up period can take anywhere from a few minutes to over a day, depending on the power plant. The fuel consumed is the start-up fuel.

State Tax Depreciation: The depreciation allowance on capital assets provided in state law, in particular for California in the COG Model. The allowance is computed using the California tax schedules from the Franchise Tax Board.

State Tax Life (Years): The book life of the asset for purposes of computing state tax depreciation and related tax items.

State Taxes: Corporate income taxes that the owner must pay to the state government, California in particular in the COG Model. These are calculated as below.

If Owner Type ="Muni", State Taxes = -CSI - SGIP

If Owner Type = "IOU, Merchant", State Taxes = State Tax Rate*(After Tax Return On Debt & Equity+ Federal Taxes- (Debt Interest+ State Tax Depreciation)-(CSI+SGIP)/ (1- State Tax Rate))

We included California Solar Initiative (CSI) and Self-Generation Incentive Program (SGIP) in the formula for the User although the COG Model does not use them in the calculations.

Time To Major Overhaul: The period between major overhauls.

Time To Major Overhaul = $\frac{\text{Hours To Major Overhaul}}{\text{Operational (Service) Hours/Year}}$

Total Acres: The total acreage of the power plant.

Total Acres = If (Isnumber (Acre Per MW), Acre Per MW * Gross MW, Acre Per Plant) +Additional Acreage

Total Air Emission Cost Conversion: Total air emission costs can be calculated as below:

Air Emissions from Lbs/MWh to Tons/Yr = Lbs Air Emissions * Annual Net Energy (GWh) *1000 / 2000

Total Annual Air Emission Costs (Excluding Capital): The total annual costs of operating the air emission equipment.

Total Annual Air Emission Costs (Excluding Capital) = Calculated Air Emissions Replacement Cost + Air Control Annual Consumables Catalyst* Annual Net Energy (GWh)*1000 + Laborer Wage*Overhead Multiplier* Air Control Annual Labor (Hours/Year)

Total Annual Environmental O&M Costs: The sum of the annual air emissions costs, water cooling costs and solid waste disposal costs.

$$\text{Total Annual Environmental Costs} = \text{Total Annual Air Emissions Costs (Excluding Capital)} + \text{Total Annual Water Treatment \& Cooling Costs (Excluding Capital)} + \text{Total Annual Solid Waste Disposal Costs}$$

Total Annual Maintenance Costs: It is the sum of the consumable maintenance costs, periodic routine maintenance costs, other routine maintenance costs, well field costs, scheduled maintenance costs and other unscheduled maintenance costs.

$$\text{Total Annual Maintenance Costs} = \text{Total Consumable Maintenance Costs} + \text{Periodic Routine Maintenance Costs} + \text{Total Other Routine Maintenance Costs} + \text{Total Well Field Costs} + \text{Total Scheduled Maintenance Costs} + \text{Total Unscheduled Maintenance Costs.}$$

Total Annual Solid Waste Disposal Costs: The total annual costs to dispose solid waste.

$$\text{Total Annual Solid Waste Disposal Costs} = \text{Total Non - Hazardous Material Disposal Costs} + \text{Hazardous Material Disposal Costs}$$

Total Annual Water Treatment Costs (Excluding Capital): The total annual costs of cooling the power plant net of water purchases. Water purchases are included in fixed O&M, and other operating costs.

$$\text{Total Annual Water Cooling Costs (Excluding Capital)} = \text{Calculated Water Treatment \& cooling Replacement Cost} + \text{Water Control Annual Consumables Catalyst* Annual Net Energy (GWh)*1000} + \text{Laborer Wage*Overhead Multiplier* Water Control Annual Labor (Hours/Year)}$$

Total Component Costs (\$): The cost for individual power plant components, for example, turbine sets, boilers, generators, control room. Reported costs may only show a sum total of all of these components.

Total Construction Costs (\$): The total cost of a power plant that includes both the instant capital cost (\$) and the financing of the construction loan.

Total Consumable Maintenance Costs: Maintenance costs associated with consumption of materials, such as lubricating oils. These costs typically are incurred on a recurring, almost daily, basis. Either formula below can be used for calculating the total consumable maintenance cost.

$$\text{Total Consumable Maintenance Costs} = \text{Consumable Maintenance Period} * \text{Total Consumable Cost Per Period,}$$

$$\text{Total Consumable Maintenance Costs} = \text{Oil Cost} + \text{Consumables Cost} + \text{Consumable Maintenance Labor}$$

Total Cost Per Overhaul: The total cost of the overhaul.

**Total Cost Per Overhaul = Major Overhaul Labor (Hrs) *
Mechanics Wage/Hour* Overhead Multiplier + Major Overhaul Replacement.**

Total Development Costs: Pre-construction costs incurred by project developers for land acquisition and preparation and project financing. These costs are recovered within the Capital Cost expenditures.

**Total Development Costs = Predevelopment Expenses + Construction
Insurance & Installation + Commitment Fee.**

Total Environmental Costs (\$/MWh): The annual costs environmental discharge control devices, such as SCR devices to reduce air emissions and cooling water discharge control measures.

**Total Environmental Costs = (Total Annual Environmental O&M Costs +
Variable RTC's & Mitigation Fees)/Load CenterEnergy (GWh)*1000**

Total Environmental Control Installation Costs: The costs of installing necessary environmental discharge control devices, such as SCR devices to reduce air emissions and cooling water discharge control measures. These costs are in addition to the permitting costs incurred to acquire the necessary environmental compliance fees.

**Total Environmental Control Costs = Total Air Emissions Control Costs +
Total Water Treatment & Cooling Control Costs**

Total Hazardous Material Disposal Costs: The total costs associated with the disposal of hazardous materials.

**Total Hazardous Material Disposal Costs = Hazardous Material Tons/Year
*(Hazardous Collection & Hauling Cost + Hazardous Landfill Tipping Cost)**

Total Instant Capital Cost (\$): The cost of purchasing and building a power plant assuming that it could be built instantaneously: Component costs, land costs, development costs, permitting costs, interconnection costs, total environmental controls costs.

**Total Instant Capital Cost = (Total Component Cost + Total Land Costs + Total
Development Costs+ Total Permitting Costs + Total Interconnection Costs +
Total
Environmental Controls)* (1+Financial Transaction Costs* Debt Financed (%))**

Total Interconnection Costs: Costs incurred to connect the power plant to the power grid beyond the busbar. These costs are highly project specific, but general values may be reported that represent "typical" cases for each technology.

**Total Interconnection Costs = Transmission Interconnection +
Fuel/Water/Sewer Costs**

Total Land Costs: The costs to acquire and develop the land necessary to construct a power plant of a particular technology. The costs shown are typical for the setting in which a technology is most likely to be developed (for example, urban for fuel cells, ranch land for

wind, industrial-zoned for gas-fired.) It is the sum of the acquisition costs and total land preparation costs.

$$\text{Total Land Costs} = \text{Acquisition Costs} + \text{Total Land Preparing Costs}$$

Total Land Preparing Costs: The total costs associated with preparing the land in advance of the erection of the power plant.

$$\text{Total Land Preparing Costs} = \text{Total Acres} * \text{Land Preparing Costs/Acre}$$

Total Net Revenues = Total Net Revenues are calculated as follows:

$$\text{Total Net Revenues} = \text{Net Revenues} * \text{Net Capacity} * \text{Annual Production of Byproducts (Lbs/kW)}$$

Total Non-Hazardous Material Disposal Costs: The total costs associated with the disposal of non-hazardous materials.

$$\text{Total Non-Hazardous Material Disposal Costs} = \text{Non Hazardous Material Tons/Year} * (\text{Non Hazardous Collection \& Hauling Cost} + \text{Non-Hazardous Landfill Tipping Cost})$$

Total Operating Expense: The total of fixed operating expense and variable operating expense.

$$\text{Total Operating Expense} = \text{Fixed Operating Expense} + \text{Variable Operating Expense}$$

Total Operating Hours Over The Life Of The Plant: The projected total hours of plant operations over the economic life of the power plant. This value is used to compute the number of maintenance cycles required.

$$\text{Total Operating Hours Over The Life Of The Plant} = \text{Equipment Life (Years)} * \text{Operational Hours/Year}$$

Total Periodic Routine Maintenance Costs: The sum of periodic routine maintenance costs incurred on a regular, expected basis. These costs may be captured in the total routine maintenance costs (see below), but this category is included in the model for flexibility purposes, and for situations that may apply to specific technologies, for example, replacement of the fuel core in fuel cells.

Total Permitting Costs: Costs incurred in applying for necessary local-use and environmental compliance permits, including direct permit fees. These costs do not include the costs of installing and operating environmental controls.

$$\text{Total Permitting Costs} = \text{Local Building Permits} + \text{Environmental Permits} + \text{Emission Reduction Credits Costs}$$

Total Return on Debt & Equity: The total net income over the entire amount, both debt and equity, invested in the power plant.

$$\text{Total Return on Debt \& Equity} = \text{Debt Payment} + \text{Equity Recovery} + \text{Total Taxes}$$

Total Routine Maintenance Costs: These are costs for significant parts and labor incurred during the year. They are more frequent but less costly than major and minor overhauls. In the COG Model, these costs are applicable to all technologies except geothermal and wind, which have their costs delineated under total other routine maintenance costs.

$$\text{Total Routine Maintenance Costs} = \text{Total Consumable Maintenance Costs} + \text{Total Periodic Routine Maintenance Costs} + \text{Total Other Routine Maintenance Costs} + \text{Total Well Field Costs}$$

Total Other Routine Maintenance Costs: These costs similar in nature to the above defined total routine maintenance cost, with added categories for certain technologies such as geothermal and wind. The listed items are specific to the technologies as provided by technology specialists. Definitions of those items should be collected from such specialists, and are beyond the scope of this guide.

Total Scheduled Maintenance Costs: The sum of the major overhaul costs and the minor overhaul costs. See **major overhauls** and **minor overhauls**.

$$\text{Total Scheduled Maintenance Costs} = \text{Major Overhaul Cost} + \text{Minor Overhaul Cost}$$

Total Tax Rate: This is the total of the state and federal taxes.

$$\text{Total Tax Rate} = \text{Federal Tax Rate} * (1 - \text{State Tax Rate}) + \text{State Tax Rate}$$

Total Unscheduled Maintenance Costs: Expected average annual costs for repairing a power plant after a forced outage or other unforeseen outage.

$$\text{Total Unscheduled Maintenance Costs} = \text{Mechanics Wage/Hour} * \text{Overhead Multiplier} * \text{Hours of Labor} + \text{Parts Costs}$$

Total Well Fields Costs: Costs incurred at geothermal plants for maintenance and operation of steam and hot-water reservoir well fields.

Transformer Losses (Percent): In the process of a transformer uplifting or down lifting the voltage, some of the power is lost. These losses are called transformer losses.

Transmission Losses (Percent): Losses incurred in the transmission lines during the transmission of electricity, usually in the form of heat or a voltage drop.

Variable Costs (\$/kW-ur or \$/MWh): Costs that change as a function of power plants use; that is, fuel costs and variable O&M (hourly labor, supply purchases). As the time horizon of the analysis expands, more costs become variable. More specifically for a power plant, these are all costs which are a function of the operation of the plant—if the plant has a zero CF, then theoretically these costs are zero.

$$\text{Variable Costs} = \text{Fuel Costs} + \text{Variable O\&M}$$

Variable O&M Costs (\$/MWh): O&M costs that are a function of the operation of the power plant (yearly maintenance and overhauls). In the Energy Commission’s COG Model, the annual costs are calculated by the following formula:

$$\begin{aligned} &\text{Variable O\&M Costs (\$/MWh)(Year Calculation Is Done)} \\ &= (\text{Variable O\&M/MWh (Base Year)} * ((1 + \text{Historical Inflation Rate}) * (1 + \text{O\&M} \\ &\text{Escalation})(\text{Start Yr} - \text{Base Yr})) * ((1 + \text{O\&M Escalation}) * (1 + \text{Forward Inflation} \\ &\text{Rate})(\text{Year Calculation Is Done} - \text{Start Yr})) \end{aligned}$$

To convert from \$/MWh to (\$/kW-yr):

$$\frac{\text{Variable O\&M Costs (\$/MWh)} * \text{Annual Load Center Energy (GWh)}}{\text{Gross Capacity (MW)}}$$

Variable Operating Expense: The same as variable costs—the sum of fuel cost and variable O&M.

Water Supply Costs (\$/Acre-Foot): The costs of acquiring water supplies in the listed region. Costs reported represent typical industrial water delivery rates found in the Regional Cost Differences report for the California ISO in 2002.

To convert the Water Supply Costs into (\$/MWh):

$$\text{Water Supply Costs} = (\text{Water Supply Costs/Acre Foot}) * \text{Water Consumption (Acre Foot)}$$

Water Treatment & Cooling Control Technology Capital Costs: It is the capital cost of purchasing and installing the water treatment and cooling control technology equipment.

$$\text{Water Treatment \& Cooling Control Technology Capital Costs} = \text{Water Cooling Control Installation Cost} * \text{Gross Capacity} * 1000$$

Water Treatment & Cooling Control Technology—The method used to cool a power plant. Different technologies use different intensities of water consumed per MWh of output, with installation and operating costs increasing as less water is used.

Weighted Average Cost Of Capital (WACC): The average cost of financing the construction of a power plant. The weighted average is calculated by multiplying the percentage of the incremental capital used for financing that comes from debt instruments and equity sources by their respective interest rates.

$$\text{WACC} = \text{Percent Equity} * \text{Cost of Equity}(\%) + \text{Percent Debt} * \text{Cost of Debt}(\%) * (1 - \text{Total Tax Rate})$$

The WACC is also used as the AFUDC rate and the discount rate—used to calculate the present value of future cash flows as well as the LC.

APPENDIX B: Federal Tax Incentives

Figure B-1 summarizes the presently available Federal tax credits. However, it should be kept in mind that these tax credits are subject to change, and may not be realizable by all power plants.

Figure B-1: Summary of Tax Credits—2013 IEPR

| Federal Renewable Energy Tax Incentives - 2008 EPAct and 2009 ARRA | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|--|------------------------|----------------|----------------------|----------------|----------------|-------------------------|----------------|----------------|--------------------|----------------|----------------|----------------|----------------|----------------------------|------|--|--|--|--|--|--|--|--|--|--|--|--|------------------|-----|-------|--|--|--|--|--|--|--|--|--|--|--|--------------------|-----|--|--|--|--|--|--|--|--|--|--|--|--|------------------|-----|-------|--|--|--|--|--|--|--|--|--|--|--|--------------------|-----|--|--|--|--|--|--|--|--|--|--|--|--|
| Technology | Coal IGCC ¹ | Wind | Biomass | | MSW / Landfill | Geothermal ² | Small Hydro | Ocean Wave | Solar ³ | Fuel Cells | Small Wind | CHP | Micro-turbines | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | Open Loop (Ag waste) | Closed Loop | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Production Tax Credit | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Credit (2008S)/MWH | | \$21 | \$10 | \$21 | \$10 | \$21 | \$10 | \$10 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Credit (1993S)/MWH | | \$15 | \$7.50 | \$15 | \$7.50 | \$15 | \$7.50 | \$7.50 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Duration (Years) | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Expiration ⁵ | 2010 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Eligibility | Merchant | Merchant | Merchant | Merchant | Merchant | Merchant | Merchant | Merchant | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Investment Tax Credit | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Credit | 20% | | | | | 10% | | | 30%/10% | 30% | 30% | 10% | 10% | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Depreciable value reduced | 10% | | | | | 5% | | | 15%/5% | 15% | 15% | 5% | 5% | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Expiration ⁵ | 2010 | | | | | NA | | | 2017 | 2017 | 2017 | 2017 | 2017 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Loss Carryforward Period (Yrs) | 20 | | | | | 20 | | | 20 | 20 | 20 | 20 | 20 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Eligibility | Merchant / IOU | | | | | Merchant / IOU | | | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant / IOU | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| ARRA Grant | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| ITC in-lieu of PTC | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Expiration ⁵ | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2017 | 2014 | 2014 | 2014 | 2014 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Eligibility | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant / IOU | Merchant / IOU | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Production Incentive⁴ | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Tier I Payment | | \$0.0 | | \$0.0 | | \$0.0 | | \$0.0 | \$0.0 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Tier II Payment | | | \$0.0 | | \$0.0 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Duration (Years) | | 10 | 10 | 10 | 10 | 10 | | 10 | 10 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Expiration ⁵ | | 2027 | 2027 | 2027 | 2018 | 2027 | | 2027 | 2027 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Eligibility | | POU/Coops | POU/Coops | POU/Coops | POU/Coops | POU/Coops | | POU/Coops | POU/Coops | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Property Tax Exemption | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Expiration ⁵ | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Notes | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 1 - IGCC Production Credit separate from REPTC. Based on "refined coal" = \$4.375/(13900 Btu/ton for anthracite / HR*(1+ParasiticLoad) for IGCC). Expiration date for ARRA ITC unclear. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 2 - Geothermal ITC does not expire. Unclear as to whether the ARRA increased the ITC for geothermal to 30% until 2014, and whether self-sales are eligible. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 3 - Solar ITC reverts to 10% in 2016. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 4 - REPI payments assumed = 0% as these have not been funded since 2009. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 5 - Expiration formulas are expressed as start year < expiration year so all years are given as the year following the expiration data. For example, for a credit with an expiration date of 12/31/2013, it is listed as 2014. | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| <table border="1"> <tr> <td>REPI Payment Shares</td> <td>2011</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> <tr> <td>REPI Tier 1 Paid</td> <td>\$0</td> <td>0.00%</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> <tr> <td>REPI Tier 1 Unpaid</td> <td>\$0</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> <tr> <td>REPI Tier 2 Paid</td> <td>\$0</td> <td>0.00%</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> <tr> <td>REPI Tier 2 Unpaid</td> <td>\$0</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> </tr> </table> | | | | | | | | | | | | | | REPI Payment Shares | 2011 | | | | | | | | | | | | | REPI Tier 1 Paid | \$0 | 0.00% | | | | | | | | | | | | REPI Tier 1 Unpaid | \$0 | | | | | | | | | | | | | REPI Tier 2 Paid | \$0 | 0.00% | | | | | | | | | | | | REPI Tier 2 Unpaid | \$0 | | | | | | | | | | | | |
| REPI Payment Shares | 2011 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| REPI Tier 1 Paid | \$0 | 0.00% | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| REPI Tier 1 Unpaid | \$0 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| REPI Tier 2 Paid | \$0 | 0.00% | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| REPI Tier 2 Unpaid | \$0 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| <p>REPI in U.S. Code: http://www.law.cornell.edu/uscode/text/42/13317 REPI CFR pdf & REPI_Q-A.pdf Tax Sources: http://dieselusa.org/incentives/incentive.cfm?incentive_Code=US13E http://www.dieselusa.org/incentives/incentive.cfm?incentive_Code=US02F http://esd.fhl.gov/sa/emp/ports/nln1-16426.pdf</p> | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

Source: Aspen Environmental.

Notes:

1. GCC Production Credit separate from REPTC. Based on "refined coal" = \$4.375/(13900 Btu/ton for anthracite/HR*[1+ParasiticLoad] for Integrated Gasification CC). Expiration date for American Recovery and Reinvestment Act Investment Tax Credit (ITC) unclear.

2. Geothermal ITC does not expire. Unclear as to whether the ARRA increased the ITC for geothermal to 30 percent until 2014, and whether self-sales are eligible.

3. Solar ITC reverts to 10 percent in 2016.

4. REPI payments scaled based on 2007 shares of paid to applications.

ATTACHMENT I: Reference for Degradation Factors

Pacific Group Electric Power LLC

Memorandum

From James L. Schoonmaker

DATE: Wednesday, December 07, 2005

TO: Will Walters

Aspen E.G.

SUBJECT: Gas Turbine Performance Degradation with Time

Below is a brief summary of the situation with regard to gas turbine and CC power plant degradation due to simple aging. The General Electric Technical Bulletin is typical of the current understanding, and is similar to views expressed by Siemens/Westinghouse, ABB and Mitsubshi.

Some general statements:

Degradation usually happens gradually over time. The root causes include deposit of airborne material - particularly silica - on turbine blades at high temperature, erosion/corrosion of blading due to other airborne salts - particularly sodium, maintenance practices such as regular blade washing - on line or offline, number of starts and operating hours. Occasional use of oil fuel also has major negative impact, as does poor air filtration and unusual airborne contaminant load.

The usual degradation pattern is "saw tooth" shaped; from initial operation to the first hot gas inspections a modern frame turbine may lose 3 percent of its capacity and heat rate. The cleaning at the hot gas inspection will recover 1 ½ to 2 percent of original (leaving 1 to 1 ½ percent loss from initial operation). There will be a further 3 percent loss over the next 24,000 hours to the second gas path inspection, and cleaning will recover most, so at the end of the second inspection the machine will lose approximately 2 to 3 percent of its original capacity. This saw tooth shaped degradation continues until gas path parts are replaced to bring the machine to original performance - typically this never occurs in practice as machines have reached their useful life cycle by the time economics would become attractive.

The description above is typical of frame turbines in California at many locations. A turbine located near the ocean may experience 5 to 6 percent loss between hot gas inspections. A turbine near a steel mill in California suffered very serious losses in the first year. A desert environment machine properly filtered to protect against silica intrusion may experience 2 percent loss. Machines subject to frequent starting cycles may degrade more quickly than

typical due to the moisture generated by cold temperatures in starting as well as differing chemistry on blade surfaces.

Typically aeroderivative turbines degrade on the high end of that of frame turbines, although repair by replacement allows easier correction of the degradation.

In a CC plant the gas turbines usually account for about 2/3 of the total plant output, so total plant performance degradation may be 2/3 or even less than gas turbines alone.

Below is the relevant portion of the Technical Bulletin reference:

General Electric Technical Bulletin GER-3567H

Last update 2000

General Electric proprietary material.


“All turbomachinery experiences losses in performance with time. Gas turbine performance degradation can be classified as recoverable or non-recoverable loss. Recoverable loss is usually associated with compressor fouling and can be partially rectified by water washing or, more thoroughly, by mechanically cleaning the compressor blades and vanes after opening the unit. Non-recoverable loss is due primarily to increased turbine and compressor clearances and changes in surface finish and airfoil contour. Because this loss is caused by reduction in component efficiencies, it cannot be recovered by operational procedures, external maintenance or compressor cleaning, but only through replacement of affected parts at recommended inspection intervals. Quantifying performance degradation is difficult because consistent, valid field data is hard to obtain. Correlation between various sites is impacted by variables such as mode of operation, contaminants in the air, humidity, fuel and diluent injection levels for NO_x . Another problem is that test instruments and procedures vary widely, often with large tolerances. Typically, performance degradation during the first 24,000 hours of operation (the normally recommended interval for a hot gas path inspection) is 2 percent to 6 percent from the performance test measurements when corrected to guaranteed conditions. This assumes degraded parts are not replaced. If replaced, the expected performance degradation is 1 percent to 1.5 percent. Recent field experience indicates that frequent off-line water washing is not only effective in reducing recoverable loss, but also reduces the rate of non-recoverable loss. One generalization that can be made from the data is that machines located in dry, hot climates typically degrade less than those in humid climate.

ATTACHMENT D: Asset Rental Prices

MODERN INDUSTRIAL ORGANIZATION

Dennis W. Carlton
University of Chicago

Jeffrey M. Perloff
University of California, Berkeley

 HarperCollins *Publishers*

TURNING AN ASSET PRICE INTO A RENTAL RATE

The appropriate cost concept to apply to capital (anything that lasts, for example, a piece of equipment, knowledge) is the rental price. So, for example, the relevant cost to a firm that has purchased its own truck is the rental rate it could earn on that truck. The analyst imagines the firm paying that rent to itself. The problem is that, although some equipment can be rented (and so data exist on the rental rate), for other equipment only a purchase price may be available. This appendix shows how to convert a purchase price to a rental price.

- Let $R(t)$ = rental price for 1 unit of capital at time t ,
 $p(t)$ = purchase price for 1 unit of capital at time t ,
 $K(t)$ = amount of capital remaining at time t , if 1 unit was purchased at time 0,
 r = interest rate,
 δ = rate of depreciation; the rate at which capital declines in its productive capacity ($\delta = -\dot{K}/K$, where a dot indicates differentiation with respect to time).

Assume that $p(t)$ is observable and you wish to calculate $R(t)$. It is a fundamental law of capital theory that the price of an asset equals the discounted present value of the rentals one could obtain from the asset. If the rental rate at time t is $R(t)$ and if $K(t)$ units of capital remain at time t , then total rental at time t is $R(t) K(t)$. Therefore,

$$p(0) = \int_0^{\infty} R(t) K(t) e^{-rt} dt, \quad [3A.1]$$

where $K(0) = 1$.

This formula for the asset price applies not just at time, 0, but at any time, y . Hence,

$$K(y) p(y) = \int_y^{\infty} R(t) K(t) e^{-r(t-y)} dt. \quad [3A.2]$$

By taking the derivative of Equation 3A.2 with respect to y , one obtains

$$\begin{aligned} \dot{K}(y) p(y) + K(y) \dot{p}(y) &= -R(y) K(y) + r \int_y^{\infty} R(t) K(t) e^{-r(t-y)} dt \\ &= -R(y) K(y) + r p(y) K(y), \end{aligned}$$

or

$$R(y) = r p(y) - \frac{\dot{K}(y) p(y)}{K(y)} - \dot{p}(y).$$

or

$$R(y) = (r + \delta - \frac{\dot{p}}{p}) p(y). \quad [3A.3]$$

In summary, the rental rate equals forgone interest plus depreciation minus any price appreciation (or decline).