CALIFORNIA ENERGY COMMISSION

COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION

DOCKET
09-IEP-1E
DATE
RECD. JAN 21 2010

FINAL STAFF REPORT

January 2010
CEC-200-2009-07SF

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Joel Klein
Principal Author

Ivin Rhyne
Manager
ELECTRICITY ANALYSIS OFFICE

Sylvia Bender
Deputy Director
ELECTRICIY SUPPLY ANALYSIS DIVISION

Melissa Jones
Executive Director

Acknowledgements

Many thanks are due to the following individuals for their contributions and technical support to this report:

Energy Commission Staff:

Al Alvarado
Paul Deaver
Barbara Byron
Gerald Braun
John Hingtgen
Barbara Crume
Steven Fosnaugh
Chris McLean
Margaret Sheridan

KEMA Consulting, Inc.:

Charles O'Donnell
Valerie Nibler

Aspen Environmental Group:

Will Walters
Richard McCann

Please use the following citation for this report:

Klein, Joel. 2009. *Comparative Costs of California Central Station Electricity Generation Technologies*, California Energy Commission, CEC-200-2009-017-SD

Table of Contents

List of Tables

List of Figures

Page

Abstract

The 2009 *Comparative Cost of California Central Station Electricity Generation Technologies Report* updates the levelized cost of generation estimates that were prepared for the *2007 Integrated Energy Policy Report* (*IEPR*). The California Energy Commission staff provides revised levelized cost estimates, including the cost assumptions for 21 central station generation technologies: 6 gas-fired, 13 renewable, nuclear, and coal-integrated gasification combined cycle. All levelized costs are developed using the Energy Commission's Cost of Generation Model. The levelized costs are useful for evaluating the financial feasibility of a generation technology and comparing the cost of one particular energy technology with another.

The analysis presented in the report is an improvement over the 2007 report in five ways. First, the staff presents a range of cost estimates (low, medium, and high) that can be expected for each of these technologies. The calculated range will allow users to consider the associated risks and uncertainties that may affect project development. Second, the staff examined the variables that may change in the future to develop a range of forward levelized cost estimates—a shortcoming identified in the *2007 IEPR*. Third, the model now calculates levelized costs using a cash-flow accounting method for merchant projects, instead of the revenue requirement approach that was used for the *2007 IEPR*. The revenue requirement accounting method can overstate the cost of merchant alternative technologies by as much as 30 percent. Fourth, the staff estimates transmission transaction costs and the cost of transmission to the first point of interconnection. Fifth, the model has the option to carry forward taxes to the following years in addition to the traditional option to take taxes in the current year. This option is used herein for the high-cost case.

Keywords: Cost of Generation, cost of electrical generation, cost of wholesale electricity, levelized costs, instant cost, overnight cost, installed cost, fuel cost, forecasting natural gas prices, fixed operation and maintenance, variable O&M, heat rate, technology, annual, alternative technologies, renewable technologies, combined cycle, simple cycle, combustion turbine, integrated gasification, coal, fuel, natural gas, nuclear fuel, heat rate degradation, capacity degradation, financial variables, capital structure, cost of capital, cost of debt, debt period, cost of equity, corporate taxes, tax benefits, depreciation period, tax credits, merchant, IOU, POU, and CPUC

Executive Summary

The goal of the staff levelized cost of generation project is to have a single set of the most current levelized cost estimates and supporting data that would contribute to energy program studies at the California Energy Commission (Energy Commission) and other state agencies. The levelized cost of a resource represents a constant cost per unit of generation that is commonly used to compare one unit's generation cost with other resources over similar periods. These levelized costs are useful for comparing the financial feasibility of different electricity generation technologies. Since most studies involving new generation or transmission require an assessment of the comparative cost of generation for various generation technologies, the data provided in this report is essential for any resource planning study.

There are numerous studies that provide levelized cost estimates for individual generation technologies, but it is difficult to compare the merits of these different estimates without understanding the underlying assumptions. Since plant characteristics, capital costs, plant operations, financing arrangements, and tax assumptions can vary, different assumptions will produce significantly different levelized cost estimates. It is, therefore, important to have a consistent set of assumptions to be able to compare the merits of each generation technology.

The *2009 Comparative Cost of California Central Station Electricity Generation Technologies Report* updates the levelized cost of generation estimates that were prepared for the *2007 Integrated Energy Policy Report* (*IEPR*). The Energy Commission staff retained the services of KEMA, Inc., to derive a set of cost drivers for renewable, coal-integrated gasification combined cycle, and nuclear generation technologies.[1] Consultants from Aspen provided the cost assumptions for natural gas generation and assisted in the development of the modeling. The Energy Commission staff used the generation technology characterizations to update the levelized cost estimates for plants that may be developed by merchants, investor-owned utilities (IOUs), and publicly owned utilities (POUs). The average levelized cost of generation results for projects starting in 2009 are summarized in **Table 1** and **Figure 1.**[2]

Merchant facilities are plants financed by private investors and sell electricity to the competitive wholesale power market. IOU plants are built by the utility and are typically less expensive than merchant facilities due to lower financing costs. However, there appear to be instances where IOU construction costs are higher. Furthermore, some merchant renewable technology plants, such as solar units, can be less expensive due to the effect of cash-flow financing with tax benefits. The POU plants are, in general, the least expensive

[1] The characterization of the different generation technologies and supporting documentation are presented in a Public Interest Energy Research (PIER) interim project report prepared by KEMA, Inc., *Renewable Energy Cost of Generation Update* (CEC-500-2009-084), July 2009.

[2] Nuclear Westinghouse AP1000, ocean-wave, and offshore wind technologies are assumed to not be viable in California until about 2018. Tables and figures for 2009 exclude these technologies.

because of lower financing costs and tax exemptions. As shown in the table and figure, POUs can build and operate a simple cycle power plant at less than one-half the cost of either of the other two developers. However, where tax benefits are large, as in the early years of this study, a merchant or IOU can build and operate a renewable technology power plant at a lower cost than the POU.

In this report, the Energy Commission staff incorporates two directives from the *2007 IEPR* and the *2008 Update Report*. First, staff now provides a range of levelized cost estimates, illustrated in **Figure 2**. These ranges reflect not only the wide array of various component costs and operational factors, such as capacity factor, but also the cost of financing and the unpredictability of future tax benefits. This figure shows that the range of costs of a technology can be more significant than the differences in average costs between generation technologies. Looking at this figure it is difficult to know for sure which of the first 13 technologies is the least costly. These large ranges demonstrate that choosing one set of assumptions leading to a point estimate of levelized cost value may not reflect actual market dynamics and possible range of costs when evaluating resource development options. The uncertainty of these costs also implies that other factors, such as environmental impact and system diversity, should be prominent considerations in system planning.

The high values and wide ranges of the simple cycle units deserve special explanation. The high cost of these units reflect their extensive use as peaking units and, as such, are not comparable to the other load-following and base load units. The wide cost ranges for the conventional simple cycle units primarily reflect the variation in potential capacity factors, which emphasizes the importance of applying reasonable operating levels for estimating levelized costs. The wide range of the hydroelectric units reflects the unusually large variation in capital costs of the various potential hydro projects.

The other IEPR directive was to determine the long-term changes in cost variables that determine levelized cost, the most significant of which is instant cost. Instant cost, sometimes referred to as *overnight cost*, is the initial capital expenditure. **Figure 3** summarizes staff's long-term projection of instant costs in real 2009 dollars. Most of the units have little or no expected improvement in terms of real cost over the 20-year period except for two of the renewable technologies that are important to California's resource development, wind and solar, which show a significant cost decline. Solar photovoltaic, which has seen cost reductions since the *2007 IEPR*, is projected to show the most improvement of all the technologies, bringing its capital cost within range of the gas-fired combined cycle units near the end of the study period.

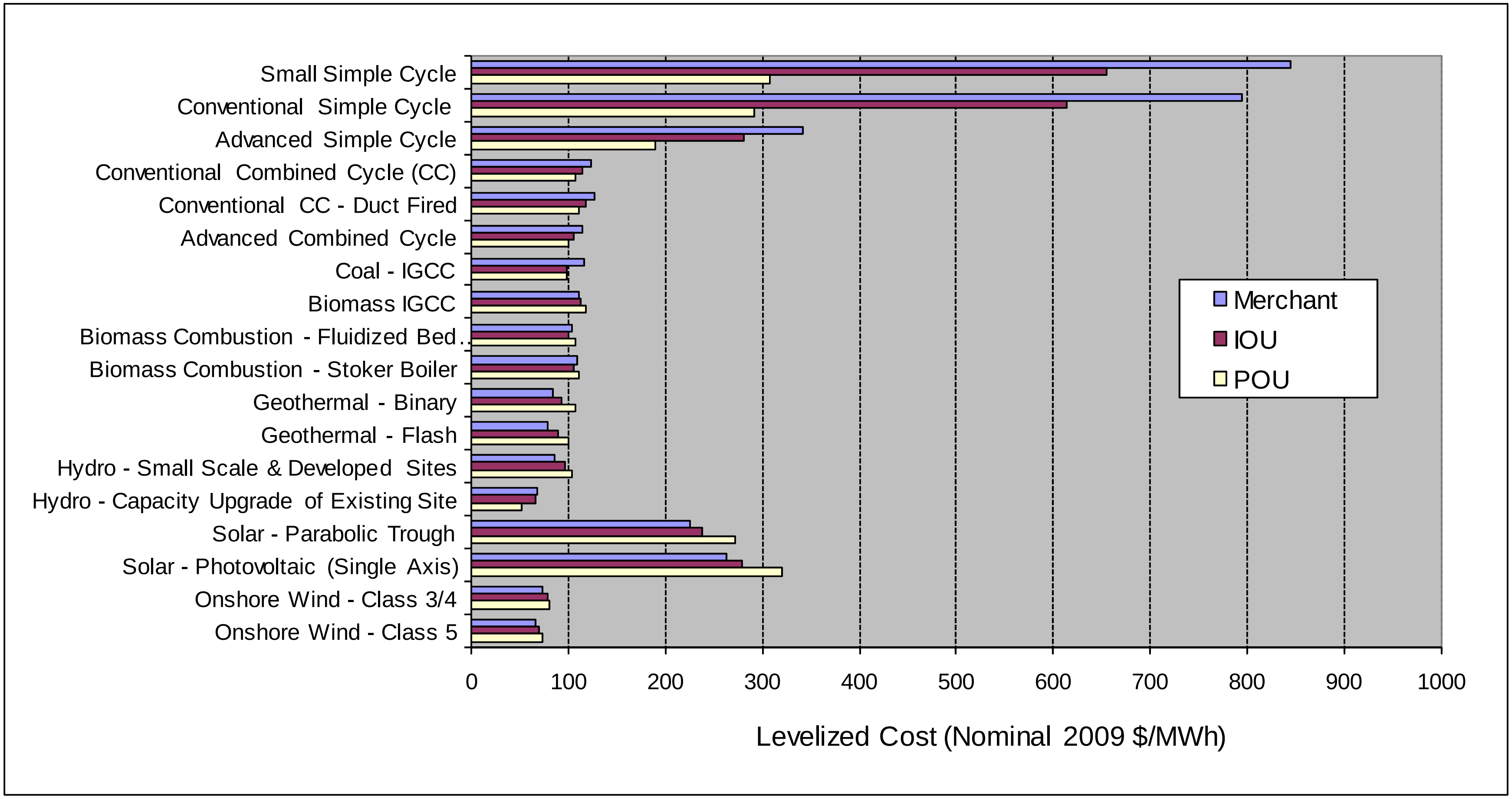
The effect of instant cost on levelized cost depends on the complicated and unpredictable assumptions of financing, operational costs and, most importantly, tax credits. Tax credits are both complicated and uncertain and are discussed within the main body of the report. The uncertainty of these assumptions can change the levelized costs dramatically.

Table 1: Summary of Average Levelized Costs—In-Service in 2009

In-Service Year = 2009 (Nominal 2009 $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Small Simple Cycle	49.9	346.91	844.31	84.43	269.31	655.69	65.57	252.90	308.01	30.80
Conventional Simple Cycle	100	326.51	794.67	79.47	252.53	614.84	61.48	239.02	291.10	29.11
Advanced Simple Cycle	200	280.91	341.84	34.18	230.86	281.03	28.10	234.37	190.29	19.03
Conventional Combined Cycle (CC)	500	758.01	123.84	12.38	701.17	114.76	11.48	657.95	107.91	10.79
Conventional CC - Duct Fired	550	727.66	127.38	12.74	670.88	117.64	11.76	627.39	110.25	11.03
Advanced Combined Cycle	800	699.97	114.36	11.44	649.05	106.23	10.62	610.57	100.14	10.01
Coal - IGCC	300	747.38	116.83	11.68	628.75	98.32	9.83	629.53	98.49	9.85
Biomass IGCC	30	656.89	109.99	11.00	666.72	111.65	11.16	701.86	117.58	11.76
Biomass Combustion - Fluidized Bed Boiler	28	683.49	104.02	10.40	661.87	100.75	10.08	698.48	106.42	10.64
Biomass Combustion - Stoker Boiler	38	726.41	108.25	10.83	710.28	105.87	10.59	740.14	110.42	11.04
Geothermal - Binary	15	427.95	83.11	8.31	475.41	93.52	9.35	505.80	106.91	10.69
Geothermal - Flash	30	422.60	78.91	7.89	467.95	88.51	8.85	494.92	100.59	10.06
Hydro - Small Scale & Developed Sites	15	165.65	86.47	8.65	181.77	95.54	9.55	189.61	103.50	10.35
Hydro - Capacity Upgrade of Existing Site	80	135.40	66.96	6.70	131.31	65.39	6.54	99.17	51.29	5.13
Solar - Parabolic Trough	250	376.70	224.70	22.47	399.04	238.27	23.83	452.71	271.52	27.15
Solar - Photovoltaic (Single Axis)	25	439.58	262.21	26.22	466.76	278.71	27.87	533.55	320.00	32.00
Onshore Wind - Class 3/4	50	203.33	72.41	7.24	217.56	77.75	7.78	220.99	80.52	8.05
Onshore Wind - Class 5	100	208.69	65.47	6.55	222.94	70.19	7.02	225.69	72.44	7.24

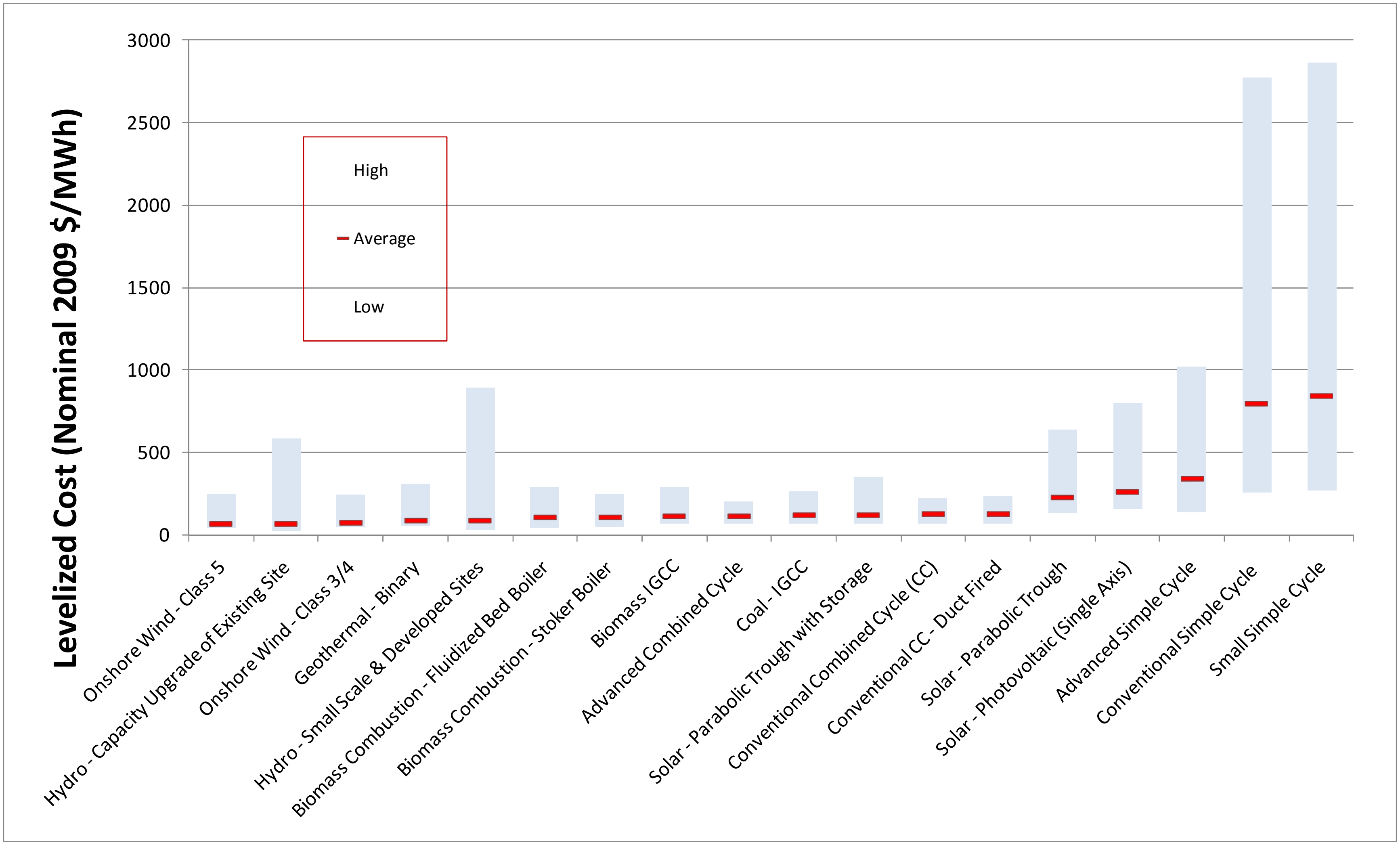
Source: Energy Commission

Figure 1: Summary of Average Levelized Costs—In-Service in 2009



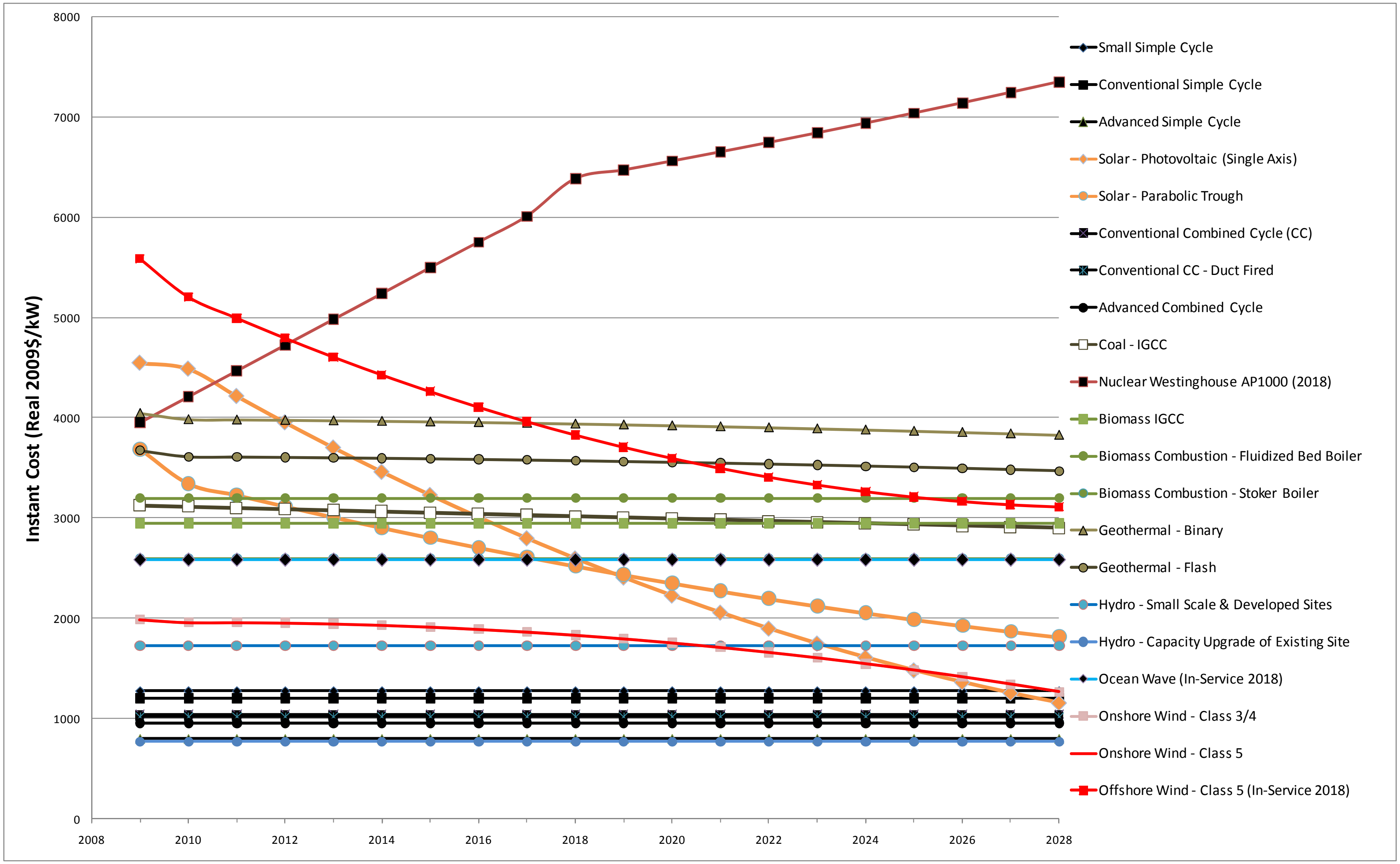
Source: Energy Commission

Figure 2: Range of Levelized Cost for a Merchant Plant In-Service in 2009



Source: Energy Commission

Figure 3: Average Instant Cost Trend (Real 2009 $/kW)

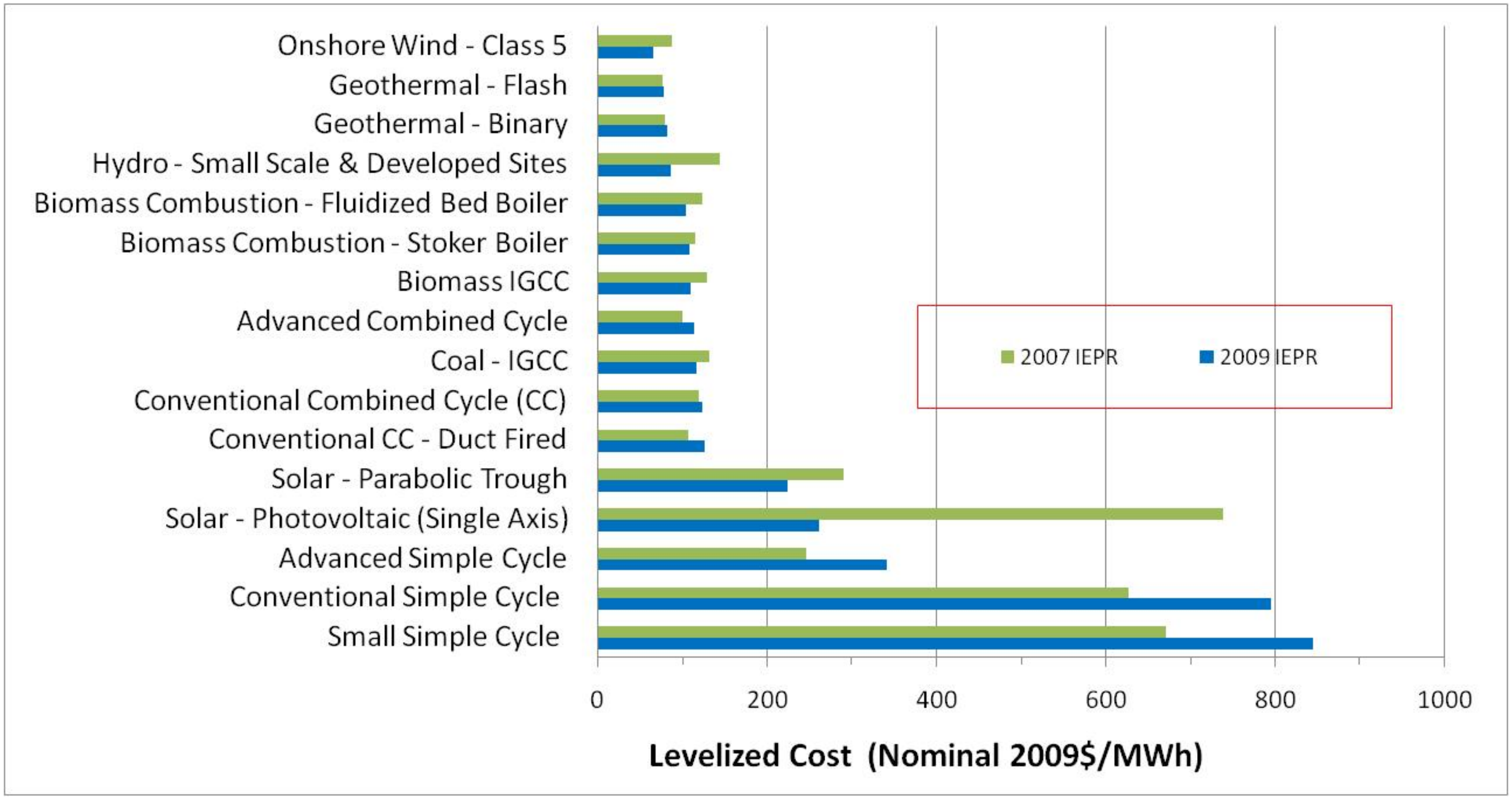


Source: Energy Commission

Figure 4 compares the average *2009 IEPR* levelized costs for merchant plants to those of the *2007 IEPR.* Although the cost differences are somewhat obscured by the complex differences in tax benefits, a number of worthwhile observations can be noted:

- Wind Class 5 has lower levelized costs compared to the *2007 IEPR b*ecause of a higher assumed capacity factor and more favorable tax benefits.
- All the biomass units have lower levelized costs, primarily because of better tax benefits.
- The coal-integrated gasification combined cycle technology shows a comparable cost to the 2007 value but would be expected to be much higher with the addition of carbon capture and sequestration that is now required by law in California to meet the environmental performance standard. However, this increased cost is offset by higher tax credits, a decrease in the base instant cost without carbon capture and sequestration, and the higher capacity factor assumed by KEMA (80 percent as compared to previous 60 percent).
- The geothermal technologies have slightly higher levelized costs primarily because of the assumed higher instant cost, which is partially offset by higher tax credits.
- The solar trough unit shows a significant decrease in levelized cost because of lower instant costs and higher tax credits.
- The solar photovoltaic unit shows a significant decrease in cost because of a decline in instant cost and increased tax benefits—which may reflect both the size difference and improvement in cost.
- Gas-fired technology levelized costs are generally higher primarily because large capital cost increases, as shown in **Table 2**. Higher average fuel cost projections also contribute to this increase in cost. Even though the increases in capital costs are greater for the combined cycle unit, the impact on levelized cost is seen more in the simple cycle units, where fixed cost is the major cost component.

Figure 4: Comparing 2009 Average Levelized Costs to *2007 IEPR* Results (In-Service in 2009)



Source: Energy Commission

Table 2: Increases in Instant Cost From *2007 IEPR* to *2009 IEPR*

Gas-Fired Technology	MW	*2007 IEPR*	*2009 IEPR*	Increase
Small Simple Cycle	49.9	$1,017	$1,292	26.95%
Conventional Simple Cycle	100	$966	$1,231	27.33%
Advanced Simple Cycle	200	$794	$827	4.12%
Conventional Combined Cycle (CC)	500	$810	$1,095	35.08%
Conventional CC - Duct Fired	550	$834	$1,080	29.56%
Advanced Combined Cycle	800	$800	$990	23.72%

Source: Energy Commission

Changes in the Cost of Generation Model

The levelized costs provided in this report were developed using the Energy Commission's Cost of Generation Model (Model). The Model was first used to produce cost of generation estimates for the *2003 IEPR*, then again for the *2007 IEPR*. The *2007 IEPR* effort greatly improved the model structure, data, and documentation, making it more accurate and easier to use. The 2009 Model has a number of improvements relative to the 2007 version:

- The Model has an option setting to produce average, high, and low levelized costs.
- The Model can estimate the cost of transmission from the interconnection point to the delivery point.
- The Model can calculate tax losses as either taken in a single year or carried forward to future years. Staff continues to use the assumption of taking losses in a single year for the average- and low-cost cases, but uses the latter for its high-cost case.
- The treatment of merchant modeling has been changed from revenue requirement to cash flow after learning that using revenue requirement overstates the levelized cost for the renewable technologies with tax benefits (tax deductions, tax credits, and accelerated depreciation) by as much as 30 percent.
- The Model has the ability to include the cost of carbon in its calculation, but staff has not used this function to calculate how carbon adders may affect levelized cost estimates, because these values have not yet been established.

The Model continues to offer two important analytical functions of the *2007 IEPR* Cost of Generation Model: screening curves and sensitivity curves to allow users to evaluate the effect of individual cost factors.

The Model can still produce a wholesale electricity price forecast, but now also provides an estimate of high and low forecast values. This feature estimates the fixed cost component and applies the variable cost factors from a production cost or market model to produce a wholesale electricity price forecast. Wholesale electricity price forecasts are useful for many resource planning studies.

The Cost of Generation Model and the levelized cost of generation results presented in an August staff draft report were the subject of a August 25, 2009, IEPR Committee workshop. This final report and the Model were modified to reflect the comments from the workshop. The staff final report and the Model will be available on the Energy Commission's website.

Using This Report

This report is intended to provide a basic assessment of some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources. However, careful consideration must be taken on how the levelized costs are used for evaluating electricity generation options. Levelized costs are typically nominal values, not precise estimates. The cost estimates are typically based on a specific set of assumptions, but in reality will vary depending on the scope of analysis and the specific generation project. Comparing the levelized cost of one generation technology against another may be useful when levelized costs are of significantly different magnitudes, but problematic where levelized costs are close.

The levelized cost analysis does not capture all of the system, environmental or other relevant attributes that would typically be examined by a portfolio manager when conducting a comprehensive "comparative value analysis" of a variety of competing resource options. The levelized costs estimates do not account for the generation service attributes, the value that different technologies have to the electricity system or represent the negotiated market prices for short-term or long-term power purchase contracts. These estimates do not predict how the units will actually operate in an electric system, how the units will affect the operation of other facilities, or their effect on total system costs. Finally, the levelized cost estimates presented in this report do not address environmental, system diversity or risk factors that are a vital planning aspect for all resource development studies. A portfolio analysis will vary depending on the particular criteria and measurement goals of each study.

The data used in this report is the most current set of generation technology characterizations available, based on surveys of recently constructed projects and information from industry experts. The COG Model has been modified to capture the attributes of different developers and examine a range of possible cost drivers that may affect levelized cost calculations. Therefore it is important to use the Model and the information in this report carefully. The following guidelines and subsequent issues are intended to provide clarity on the proper use of this report:

- Levelized cost, or for that matter any generation or transmission study, should not rely on single point estimates. There is wide variation in operational and cost data. Single point values are based on one set of conditional assumptions are simplistic and will not represent the range of costs that a developer may encounter. All studies should be based on a range of data to capture the uncertainties that developers and ratepayers will likely encounter.

- Where the use of single point estimates become unavoidable (for example, setting contractual terms), the assumptions should be carefully documented to allow replication and understanding of the results.

Additional studies are required to explore the implications of these large cost bandwidths. Staff has identified the following two study areas:

- The data and levelized costs reported in the COG Report should be integrated into a decision analysis platform, such as the RAND robust decision-making (RDM) studies to assess the meaning and impact of the large bandwidth of costs.
- The fixed cost data reported in the COG Report should be combined with production cost simulations to produce scenario studies in order to assess the implications of this large bandwidth.
- The characterization of technologies included in this report and supporting documentation provides a baseline range of assumptions that have undergone public scrutiny and comments. Use of values outside these ranges should be well-supported and documented.
- The data collected for this COG Report is applicable to statewide transmission studies and should be used to help characterize the cost inputs to such studies.
- In the absence of project-specific or scenario-specific models of levelized cost, the COG Model should be used as a default standard for generating levelized costs as either an input to further analysis or as a standalone result.

Organization of Report

The report is organized as follows:

- Chapter 1 reports the levelized cost estimates—the output of the Model. The chapter provides the levelized cost estimates for 21 technologies. The levelized cost estimates and the component costs are provided for three classes of developers: merchant, IOUs, and POUs, often referred to as municipal utilities. These costs will be provided at three levels: high, average, and low.
- Chapter 2 summarizes the inputs to the data assumptions for the three cost levels.
- Appendix A provides a general description of the Energy Commission's Cost of Generation Model, instructions on how to use the Model, and a description of the various unique features of the Model, such as screening and sensitivity curves.
- Appendix B provides component, detailed levelized costs for merchant plants, IOUs, and POUs in both dollars per megawatt-hour ($/MWh) and dollars per kilowatt-year ($/kW-Year).

- Appendix C provides the documentation for the gas-fired technology data assumptions provided in Chapter 2.
- Appendix D documents the natural gas fuel prices, including the method for developing the high and low gas prices.
- Appendix E provides the documentation for the transmission loss and cost data.
- Appendix F provides a description of the Revenue Requirement and Cash-Flow financial accounting techniques used in the COG Model.
- Appendix G provides a list of contacts if further information about the Model or model data is needed.
- Appendix H summarizes the staff's response to comments received at or as result of the August 25, 2009, workshop on the COG Model and Report.

CHAPTER 1: Summary of Technology Costs

This chapter summarizes the estimated levelized costs of the 21 technologies using the Cost of Generation Model (Model), which include nuclear, fossil fuel, and various renewable technologies. The levelized costs include a range of average, high, and low estimates. This chapter also compares the average levelized cost estimates to the *2007 Integrated Energy Policy Report (IEPR)* results.

Definition of Levelized Cost

The levelized cost of a resource represents a constant cost per unit of generation computed to compare one unit's generation costs with other resources over similar periods. This is necessary because both the costs and generation capabilities differ dramatically from year to year between generation technologies, making spot comparisons using any year problematic.

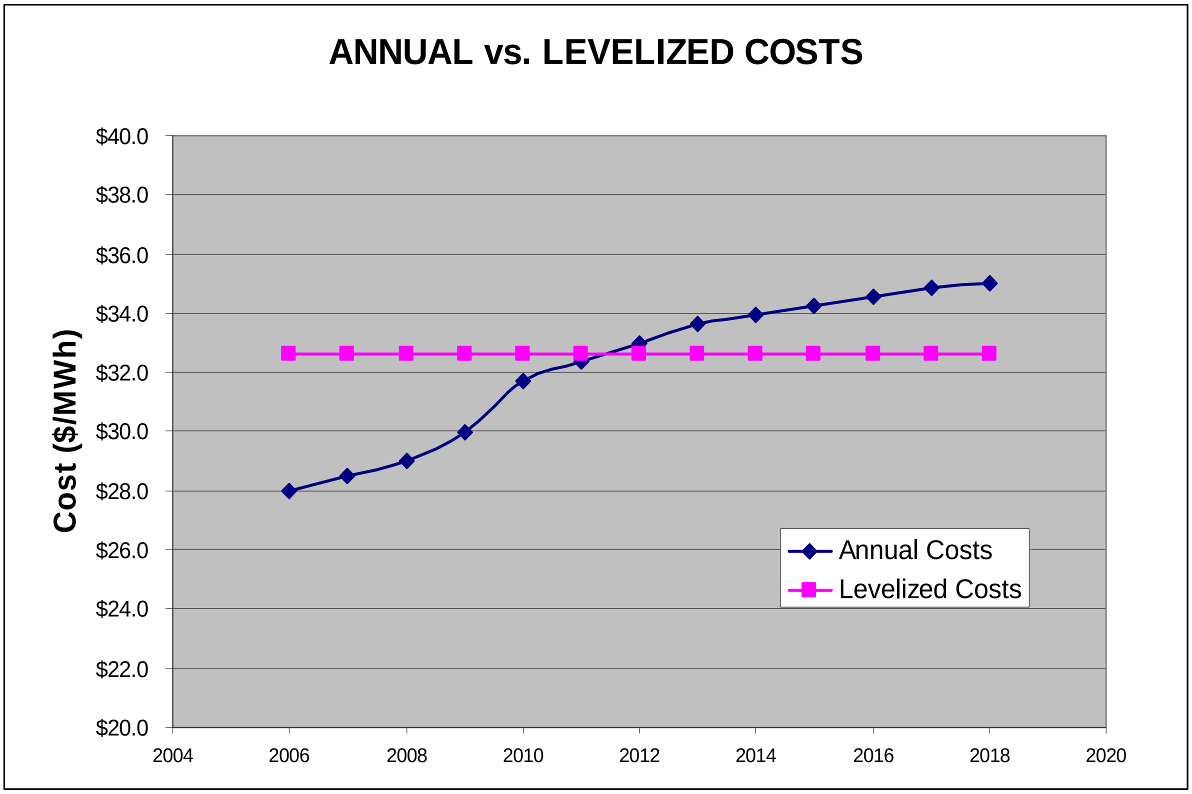
The levelized cost formula used in this model first sums the net present value of the individual cost components and then computes the annual payment with interest (or discount rate, *r*) required to pay off that present value over the specified period *T*. The formula is as follows:

$$\text{Levelized cost} = \sum_{t=1}^{T} \frac{Cost_t}{(1+r)^t} * \frac{r*(1+r)^T}{((1+r)^T - 1)}$$

These results are presented as a cost per unit of generation over the period under investigation. This 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 dollars per megawatt-hour ($/MWh) or cents per kilowatt-hour (¢/kWh).

Levelized cost is generated by the Cost of Generation Model, using multiple algorithms. Using dozens of cost, financial, and tax assumptions, the Model calculates the annual costs for a technology on an annual basis, finds a present value of those annual costs, and then calculates a levelized cost. **Figure 5** is a fictitious illustration of the relationship between annual costs and levelized costs. This relationship is defined by the fact that levelized cost values are equal to the net present value of the current and future annual costs. This annualized (or levelized) cost value allows for the comparison of one technology against the other, whereas the differing annual costs are not easily compared.

Figure 5: Illustration of Levelized Cost



Source: Energy Commission

Levelized Cost Components

Levelized costs consist of fixed and variable cost components as shown in **Table 3**.

All of these costs vary depending on whether the project is a merchant facility, an investor-owned utility (IOU), or a publicly owned utility (POU). In addition, the costs can vary with location because of differing land costs, fuel costs, construction costs, operational costs, and environmental licensing costs. These costs are discussed in detail in Chapter 2 but are defined briefly as follows.

Table 3: Summary of Levelized Cost Components

Fixed Cost
Capital and Financing – The total cost of construction, including financing the plant
Insurance – The cost of insuring the power plant
Ad Valorem – Property taxes
Fixed O&M – Staffing and other costs that are independent of operating hours
Corporate Taxes – State and federal taxes
Variable Costs
Fuel Cost – The cost of the fuel used
Variable O&M – Operation and maintenance costs that are a function of operating hours

Source: Energy Commission

Capital and Financing Costs

The capital cost includes the total costs of construction: land purchase and development; permitting including emission reduction credits; the power plant equipment; interconnection including transmission costs; and environmental control equipment. The financing costs are those incurred through debt and equity financing and are incurred by the developer annually in a manner similar to financing a home. The irregular annual costs, therefore, are levelized by this cost structure.

Insurance Cost

Insurance is the cost of insuring the power plant, similar to insuring a home. The annual costs are based on an estimated first-year cost and are then escalated by nominal inflation throughout the life of the power plant. The first-year cost is estimated as a percentage of the installed cost per kilowatt for a merchant facility and POU plant. For an IOU plant, the first-year cost is a percentage of the book value.[3]

Ad Valorem

Ad valorem costs are annual property tax payments paid as a percentage of the assessed value and are 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 State Board of Equalization as a percentage of book value for an IOU and as depreciation-factored value for a merchant facility.

[3] Book value is the net of all assets less all liabilities.

Fixed Operating and Maintenance

Fixed operating and maintenance (O&M) costs are the costs that occur regardless of how much the plant operates. These costs are not uniformly defined by all interested parties but generally include staffing, overhead and equipment (including leasing), regulatory filings, and miscellaneous direct costs.

Corporate Taxes

Corporate taxes are state and federal taxes, which are not applicable to a POU. The calculation of these taxes is different for a merchant facility than for an IOU. Neither calculation method lends itself to a simple explanation, but in general the taxes depend on depreciated values and are adjusted for interest on debt payments. The federal taxes are adjusted for the state taxes similar to an adjustment for a homeowner.

Fuel Cost

Fuel cost is the cost of fuel, most commonly expressed in dollars per megawatt-hour. 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 (dollars per million Btu [$/MMBtu]). This includes start-up fuel costs, as well as the on-line operating fuel usage. Allowance is made in the calculation for the degradation of a power plant's heat rate over time.

Variable Operations and Maintenance

Variable O&M costs are a function of the number of hours a power plant operates. Most importantly, this includes yearly maintenance and overhauls. Variable O&M also includes repairs for forced outages, consumables (non-fuel products), water supply, and annual environmental costs.

Summary of Levelized Costs

Table 4 summarizes average levelized costs for the various generation technologies, depending on whether they are developed by merchant owners, IOUs, or POUs[4]. The levelized costs are provided in the most common formats, dollars per kilowatt-year ($/kW-Year), $/MWh and ¢/kWh. All costs are in nominal dollars and are for generation units that begin operation in 2009. **Table 5** shows the corresponding data for the technologies that begin operation in 2018, when the ocean wave, offshore wind, and nuclear technologies are

[4] Nuclear Westinghouse AP1000, ocean-wave, and offshore wind technologies are assumed to not be viable in California until about 2018. Tables and figures for 2009 exclude these technologies.

assumed to have become viable in California. **Figure 6** and **Figure 7** show this same information as graphs.

This comparison of costs should always be used with discretion since these technologies are not interchangeable in their value to the system, However, a number of cost differences can be noted for general screening purposes. In general, the IOU plants are less expensive than the merchant facilities because of lower financing costs. However, the merchant plants for some of the renewable technologies, such as the solar units, become less expensive because of the effect of cash-flow financing and tax benefits. The POU plants are the least expensive because of lower financing costs and tax exemptions. This difference is most significant for the simple cycle units, where levelized costs for merchant or IOU projects are twice that of a POU.

A shortcoming noted in the *2007 IEPR* was that the levelized cost estimates did not capture long-term changes in cost variables, the most significant of which determining levelized cost is instant cost. Instant cost, sometimes referred to as *overnight cost*, is the initial capital expenditure. **Figure 8** summarizes the long-term trend in instant cost in real 2009 dollars. Most of the units have little or no expected improvement over the 20-year period, but two of the renewable technologies that are important to California's resource development, wind and solar, show a significant cost decline. Solar photovoltaic, which has shown dramatic cost change since 2007, is expected to show the most improvement of all the technologies, bringing its capital cost within range of the gas-fired combined cycle units.

The variations in levelized costs depend on a complicated set of assumptions on financing, operational costs, and, most importantly, tax credits. The patterns of the levelized costs become indecipherable when captured in a single figure. Accordingly, the levelized cost estimates are broken up into four figures for average merchant costs: **Figure 9** shows the trend for Conventional Technologies, **Figure 10** for Renewable Technologies, **Figure 11** for Base Load Technologies, and **Figure 12** for Load Following and Intermittent Technologies.

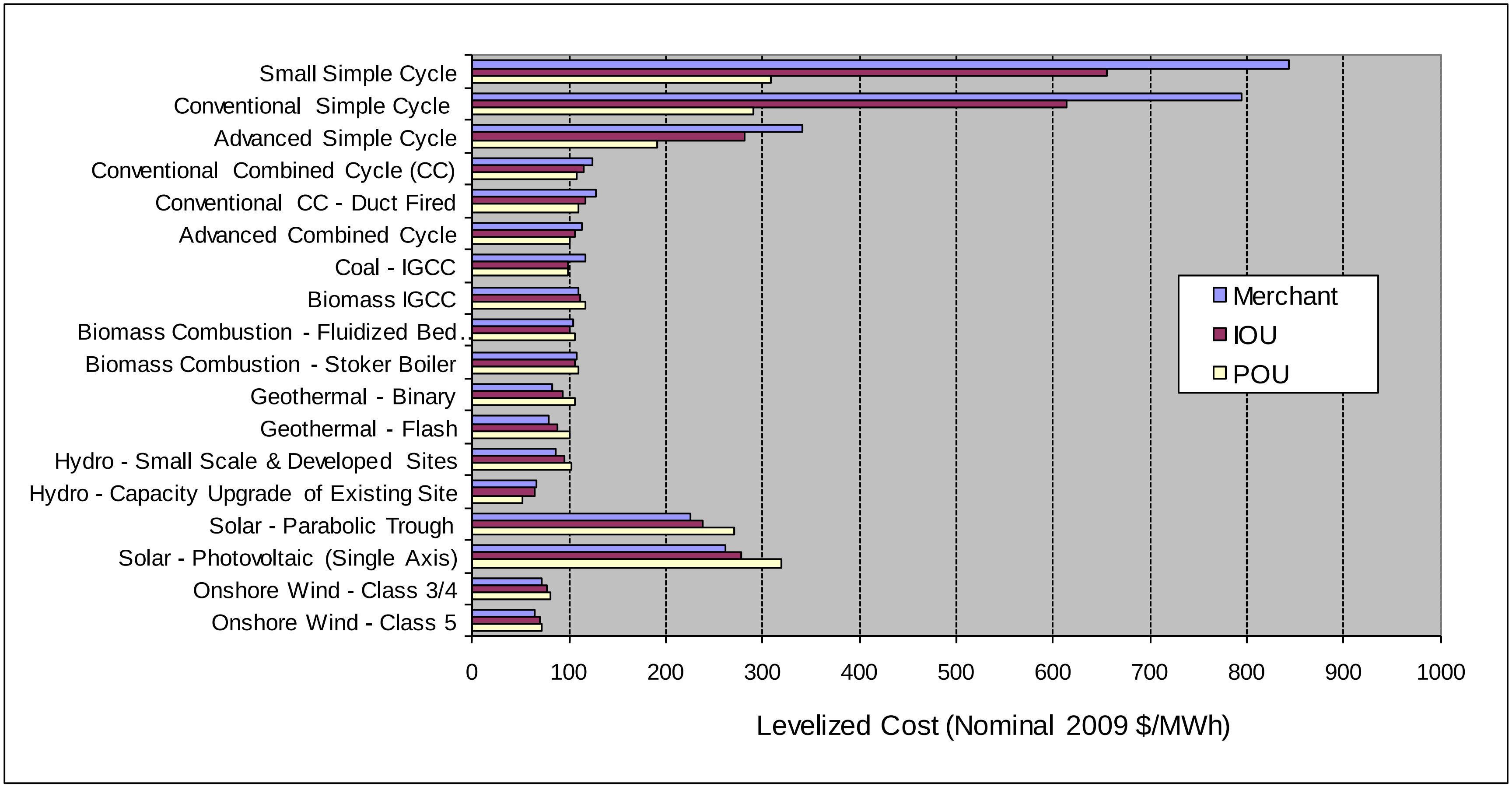
Tax credits, which are both complicated and uncertain, obscure the interpretation of this data, b**u**t it is clear that real levelized cost of gas-fired and biomass technologies trend upward, primarily from fuel cost increases. Nuclear continues to rise beyond competitive range. Wind, coal-integrated gasification combined cycle (coal-IGCC), and solar technologies trend downward. The other technologies show no or very little cost improvement. The jumps in the years between 2012 and 2018 reflect the end of federal tax credits included in both the 2008 Energy Policy Act and the 2009 American Recovery and Reinvestment Act.

Table 4: Summary of Average Levelized Costs—In-Service in 2009

In-Service Year = 2009 (Nominal 2009 $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Small Simple Cycle	49.9	346.91	844.31	84.43	269.31	655.69	65.57	252.90	308.01	30.80
Conventional Simple Cycle	100	326.51	794.67	79.47	252.53	614.84	61.48	239.02	291.10	29.11
Advanced Simple Cycle	200	280.91	341.84	34.18	230.86	281.03	28.10	234.37	190.29	19.03
Conventional Combined Cycle (CC)	500	758.01	123.84	12.38	701.17	114.76	11.48	657.95	107.91	10.79
Conventional CC - Duct Fired	550	727.66	127.38	12.74	670.88	117.64	11.76	627.39	110.25	11.03
Advanced Combined Cycle	800	699.97	114.36	11.44	649.05	106.23	10.62	610.57	100.14	10.01
Coal - IGCC	300	747.38	116.83	11.68	628.75	98.32	9.83	629.53	98.49	9.85
Biomass IGCC	30	656.89	109.99	11.00	666.72	111.65	11.16	701.86	117.58	11.76
Biomass Combustion - Fluidized Bed Boiler	28	683.49	104.02	10.40	661.87	100.75	10.08	698.48	106.42	10.64
Biomass Combustion - Stoker Boiler	38	726.41	108.25	10.83	710.28	105.87	10.59	740.14	110.42	11.04
Geothermal - Binary	15	427.95	83.11	8.31	475.41	93.52	9.35	505.80	106.91	10.69
Geothermal - Flash	30	422.60	78.91	7.89	467.95	88.51	8.85	494.92	100.59	10.06
Hydro - Small Scale & Developed Sites	15	165.65	86.47	8.65	181.77	95.54	9.55	189.61	103.50	10.35
Hydro - Capacity Upgrade of Existing Site	80	135.40	66.96	6.70	131.31	65.39	6.54	99.17	51.29	5.13
Solar - Parabolic Trough	250	376.70	224.70	22.47	399.04	238.27	23.83	452.71	271.52	27.15
Solar - Photovoltaic (Single Axis)	25	439.58	262.21	26.22	466.76	278.71	27.87	533.55	320.00	32.00
Onshore Wind - Class 3/4	50	203.33	72.41	7.24	217.56	77.75	7.78	220.99	80.52	8.05
Onshore Wind - Class 5	100	208.69	65.47	6.55	222.94	70.19	7.02	225.69	72.44	7.24

Source: Energy Commission

Figure 6: Summary of Average Levelized Costs—In-Service 2009



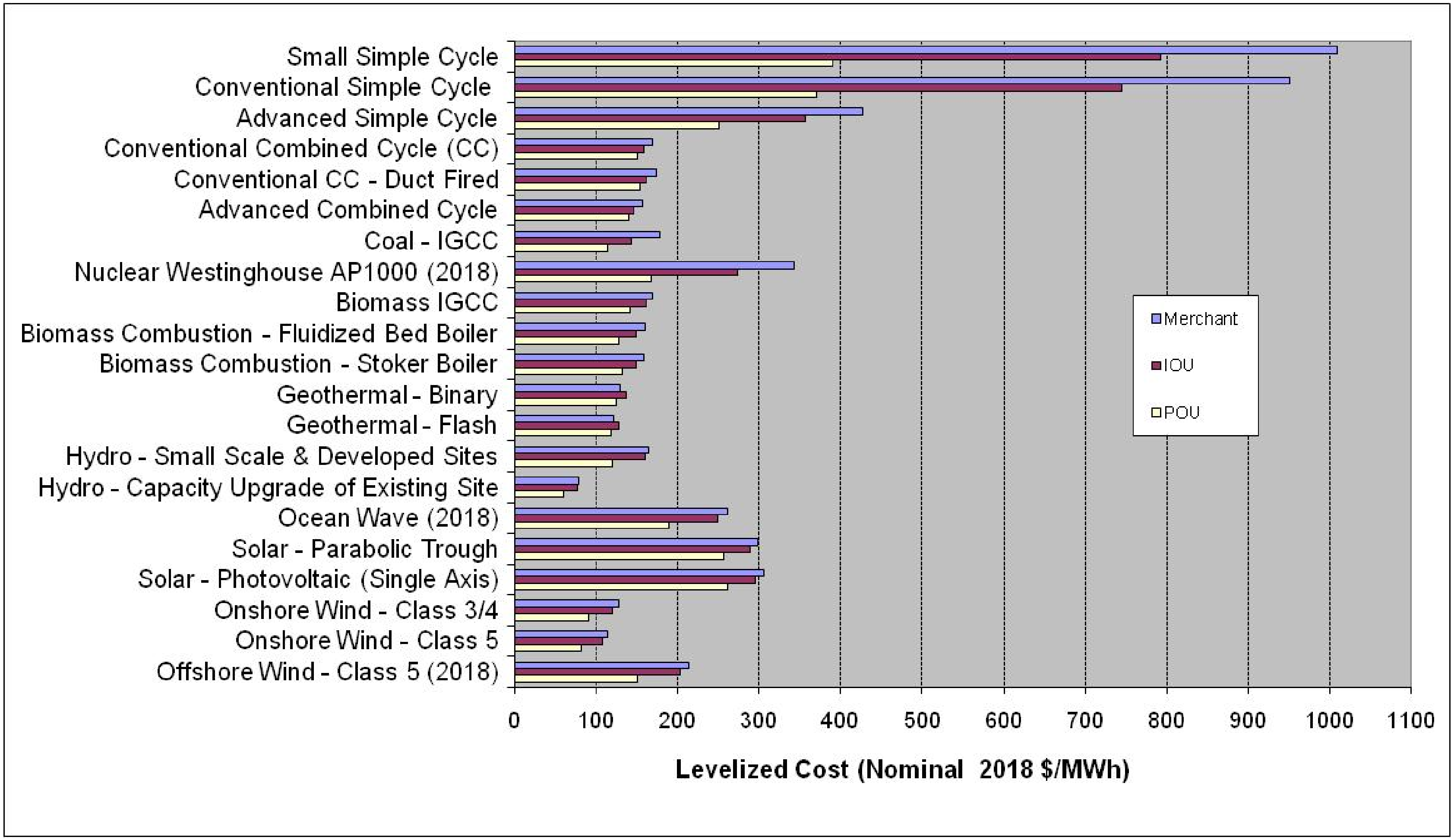
Source: Energy Commission

Table 5: Summary of Average Levelized Costs—In-Service in 2018

In-Service Year = 2018 (Nominal 2018 $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Small Simple Cycle	49.9	414.60	1009.05	100.91	325.28	791.95	79.20	319.89	389.59	38.96
Conventional Simple Cycle	100	390.84	951.22	95.12	305.67	744.21	74.42	303.61	369.76	36.98
Advanced Simple Cycle	200	346.62	421.80	42.18	288.69	351.44	35.14	304.98	247.62	24.76
Conventional Combined Cycle (CC)	500	1036.06	169.27	16.93	968.66	158.54	15.85	916.25	150.28	15.03
Conventional CC - Duct Fired	550	992.58	173.75	17.38	925.36	162.27	16.23	872.76	153.37	15.34
Advanced Combined Cycle	800	958.86	156.66	15.67	898.41	147.04	14.70	851.64	139.68	13.97
Coal - IGCC	300	2422.09	178.14	17.81	911.10	142.48	14.25	723.39	113.17	11.32
Nuclear Westinghouse AP1000 (2018)	960	1139.56	342.41	34.24	1929.55	273.07	27.31	1171.66	166.85	16.68
Biomass IGCC	30	1006.20	168.48	16.85	966.60	161.86	16.19	841.43	140.97	14.10
Biomass Combustion - Fluidized Bed Boiler	28	1054.11	160.43	16.04	974.35	148.32	14.83	837.48	127.60	12.76
Biomass Combustion - Stoker Boiler	38	1061.71	158.22	15.82	998.40	148.82	14.88	890.68	132.88	13.29
Geothermal - Binary	15	666.46	129.42	12.94	695.05	136.73	13.67	591.29	124.98	12.50
Geothermal - Flash	30	646.49	120.72	12.07	674.90	127.66	12.77	580.53	117.99	11.80
Hydro - Small Scale & Developed Sites	15	315.28	164.59	16.46	304.10	159.84	15.98	220.33	120.27	12.03
Hydro - Capacity Upgrade of Existing Site	80	157.31	77.80	7.78	152.81	76.09	7.61	115.80	59.88	5.99
Ocean Wave (2018)	40	511.74	261.71	26.17	485.22	249.02	24.90	361.85	189.33	18.93
Solar - Parabolic Trough	250	500.65	298.64	29.86	483.85	288.92	28.89	427.05	256.13	25.61
Solar - Photovoltaic (Single Axis)	25	512.14	305.50	30.55	494.76	295.43	29.54	436.12	261.57	26.16
Onshore Wind - Class 3/4	50	357.14	127.19	12.72	337.44	120.59	12.06	248.91	90.69	9.07
Onshore Wind - Class 5	100	363.57	114.06	11.41	343.90	108.27	10.83	255.53	82.02	8.20
Offshore Wind - Class 5 (2018)	350	731.39	214.16	21.42	690.08	202.78	20.28	504.75	151.21	15.12

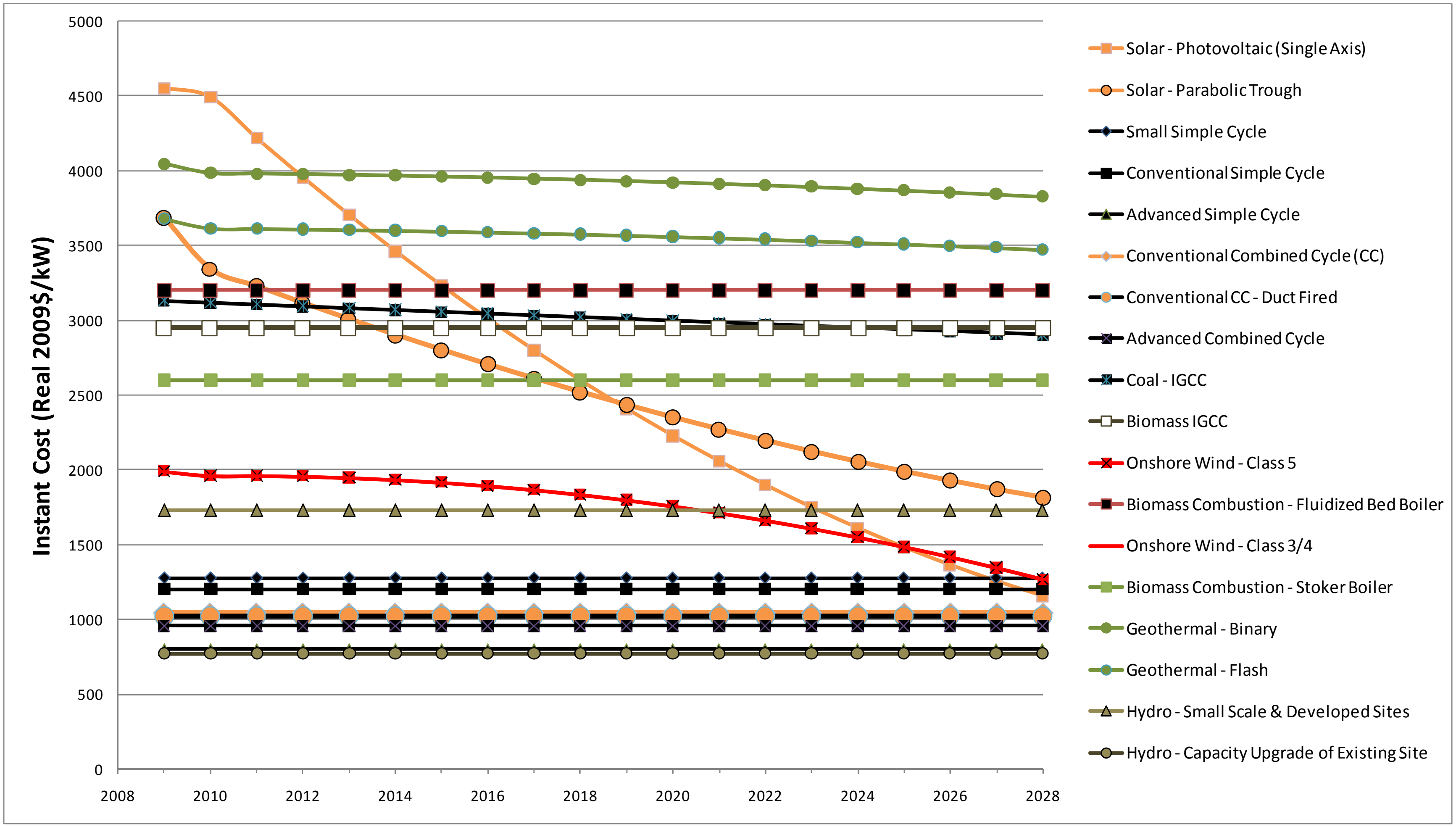
Source: Energy Commission

Figure 7: Summary of Average Levelized Costs—In-Service in 2018



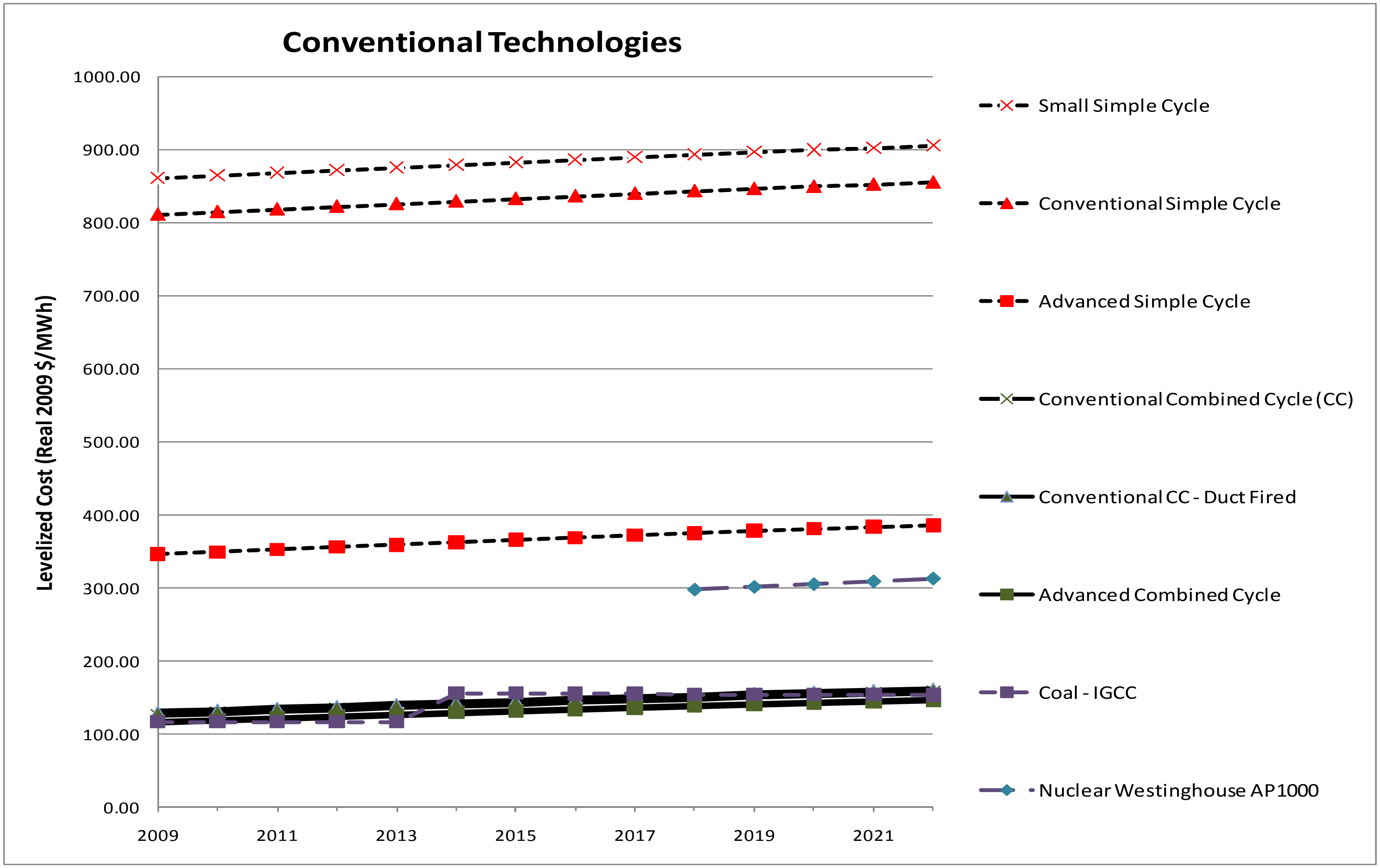
Source: Energy Commission

Figure 8: Average Instant Cost Trend (Real 2009 $/kW)



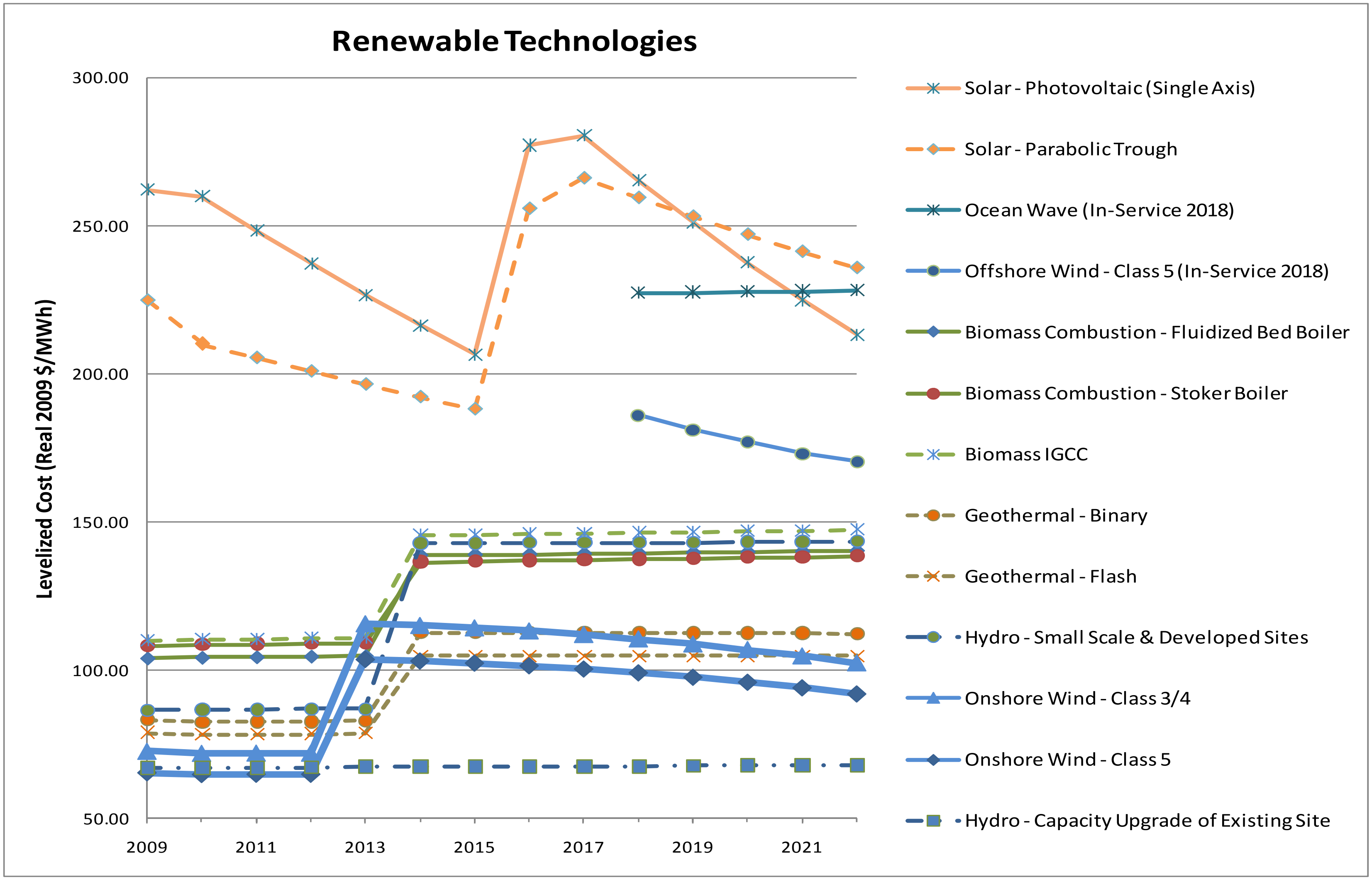
Source: Energy Commission

Figure 9: Average Merchant Levelized Cost Trend for Conventional Technologies



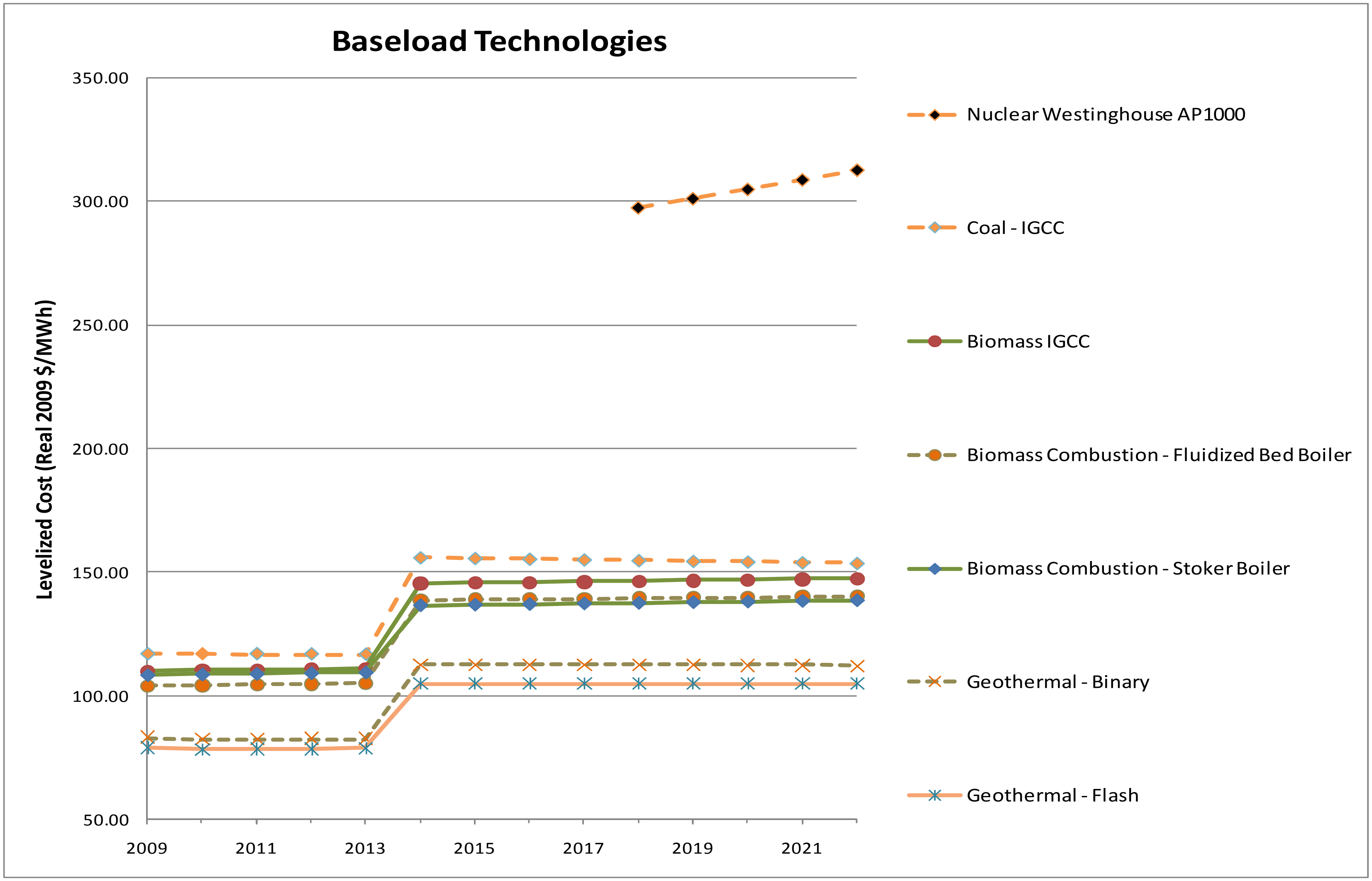
Source: Aspen Consulting

Figure 10: Average Merchant Levelized Cost Trend for Renewable Technologies



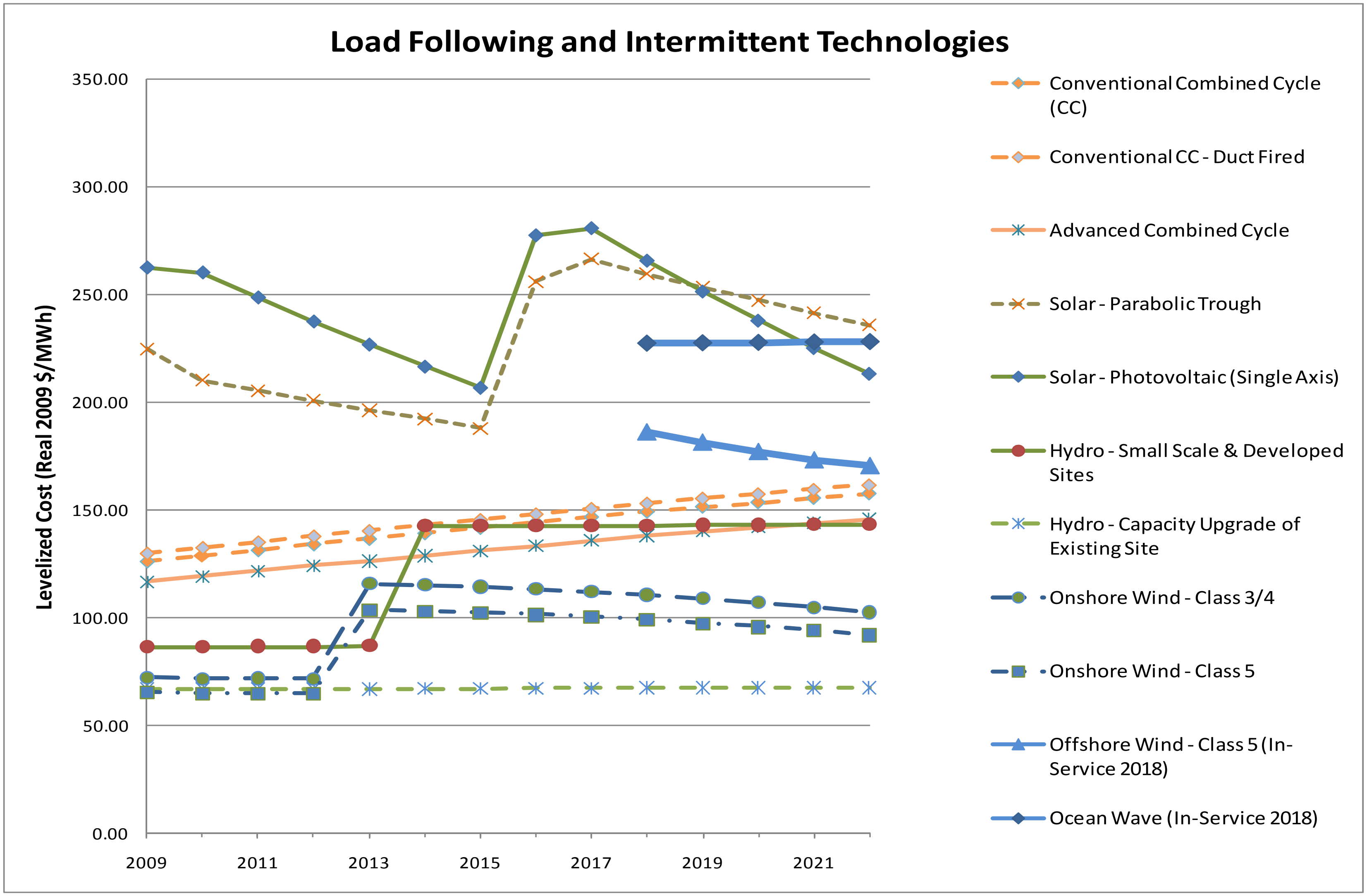
Source: Aspen Consulting

Figure 11: Average Merchant Levelized Cost Trend for Baseload Technologies



Source: Aspen Consulting

Figure 12: Average Merchant Levelized Cost Trend for Load Following and Intermittent Technologies



Source: Aspen Consulting

Component Costs

Table 6 shows the levelized cost components in $/MWh for a merchant plant coming on-line in 2009. **Figure 13** shows the same data differentiating only between the fixed and variable costs. **Table 7** and **Figure 14** show the comparable information for a merchant plant coming on-line in 2018.

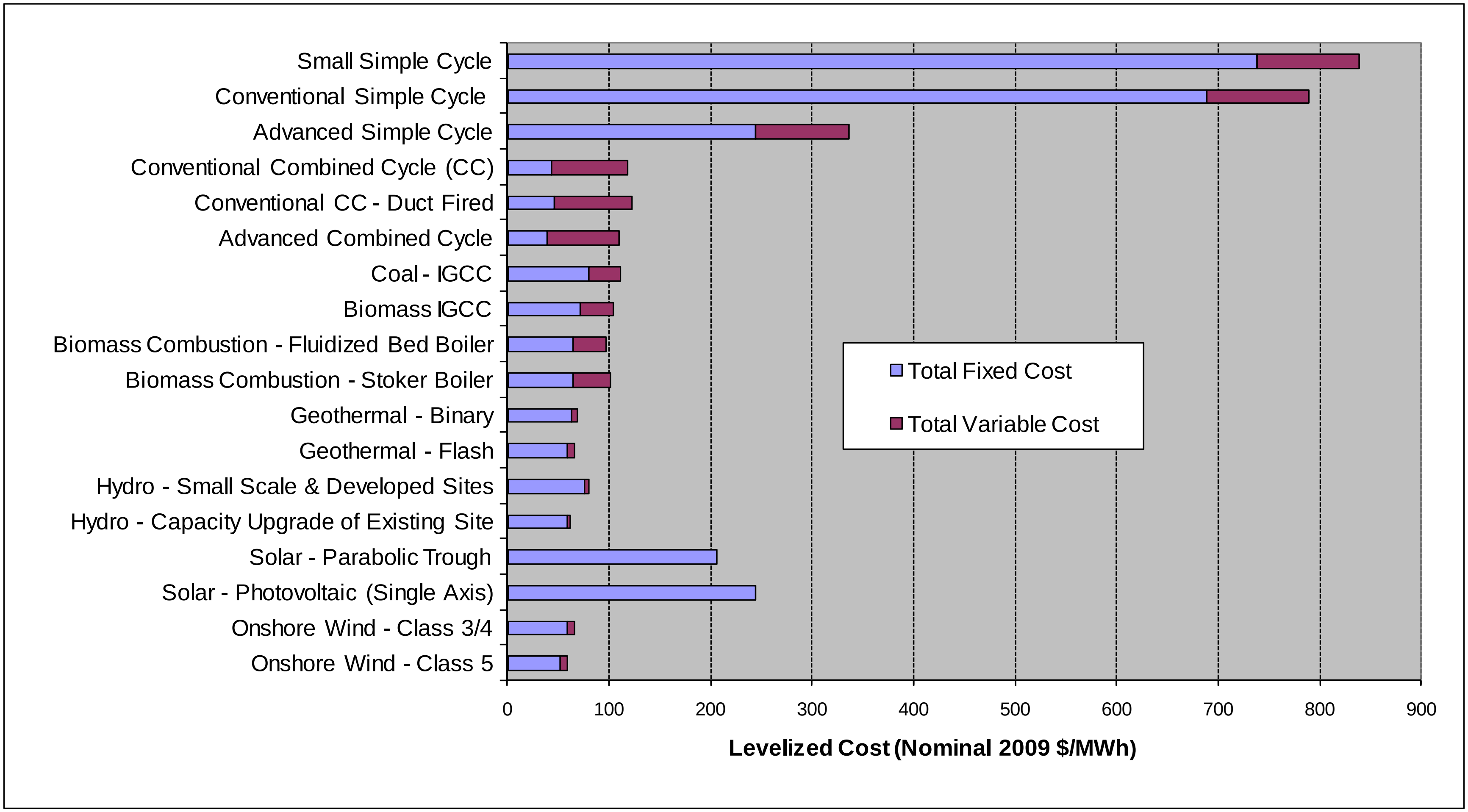
Even though the operating portion of the levelized cost for simple cycle units is only about 15–18 percent of the cost, depending on the year, it is more than 65–70 percent of the total cost for a combined cycle unit. For coal-IGCC and the biomass units, the operating cost is not as large, but still significant. For the other units, operating costs are a small portion of their total cost.

Table 6: Average Levelized Cost Components for In-Service in 2009—Merchant Plants

		$/MWh (Nominal $)											¢/kWh
In-Service Year = 2009 (Nominal 2009 $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**	**Total Levelized Cost**
Small Simple Cycle	49.9	482.17	23.44	31.87	66.81	134.18	**738.46**	95.54	5.08	**100.62**	5.24	**844.31**	**84.43**
Conventional Simple Cycle	100	459.43	22.33	30.36	48.56	128.14	**688.82**	95.54	5.08	**100.62**	5.24	**794.67**	**79.47**
Advanced Simple Cycle	200	158.70	7.71	10.49	22.79	44.28	**243.98**	88.15	4.47	**92.62**	5.24	**341.84**	**34.18**
Conventional Combined Cycle (CC)	500	28.64	1.38	1.88	1.61	9.42	**42.93**	72.05	3.66	**75.71**	5.21	**123.84**	**12.38**
Conventional CC - Duct Fired	550	30.26	1.46	1.99	1.67	9.95	**45.32**	73.19	3.66	**76.85**	5.21	**127.38**	**12.74**
Advanced Combined Cycle	800	25.91	1.25	1.70	1.34	8.52	**38.73**	67.17	3.26	**70.43**	5.21	**114.36**	**11.44**
Coal - IGCC	300	72.98	3.83	5.21	9.38	-11.33	**80.08**	19.38	11.98	**31.36**	5.38	**116.83**	**11.68**
Biomass IGCC	30	59.97	3.84	5.08	29.12	-26.40	**71.62**	26.75	5.08	**31.84**	6.54	**109.99**	**11.00**
Biomass Combustion - Fluidized Bed Boiler	28	60.92	3.78	5.00	17.56	-23.00	**64.26**	27.35	5.83	**33.18**	6.58	**104.02**	**10.40**
Biomass Combustion - Stoker Boiler	38	48.64	3.02	4.00	27.66	-18.49	**64.83**	28.06	8.91	**36.97**	6.45	**108.25**	**10.83**
Geothermal - Binary	15	84.76	6.52	9.85	11.15	-48.94	**63.33**	0.00	5.94	**5.94**	13.83	**83.11**	**8.31**
Geothermal - Flash	30	74.41	5.74	8.67	13.19	-43.22	**58.79**	0.00	6.61	**6.61**	13.51	**78.91**	**7.89**
Hydro - Small Scale & Developed Sites	15	93.65	7.03	10.62	11.10	-46.78	**75.62**	0.00	4.85	**4.85**	6.00	**86.47**	**8.65**
Hydro - Capacity Upgrade of Existing Site	80	43.98	2.97	4.48	7.53	-0.84	**58.12**	0.00	3.16	**3.16**	5.68	**66.96**	**6.70**
Solar - Parabolic Trough	250	257.53	16.58	0.00	47.03	-114.69	**206.45**	0.00	0.00	**0.00**	18.26	**224.70**	**22.47**
Solar - Photovoltaic (Single Axis)	25	317.91	20.47	0.00	47.03	-141.44	**243.96**	0.00	0.00	**0.00**	18.26	**262.21**	**26.22**
Onshore Wind - Class 3/4	50	74.66	5.53	8.36	5.90	-36.18	**58.28**	0.00	6.97	**6.97**	7.16	**72.41**	**7.24**
Onshore Wind - Class 5	100	65.77	4.87	7.37	5.20	-31.88	**51.34**	0.00	6.97	**6.97**	7.16	**65.47**	**6.55**

Source: Energy Commission

Figure 13: Fixed and Variable Costs for In-Service in 2009—Merchant Plants



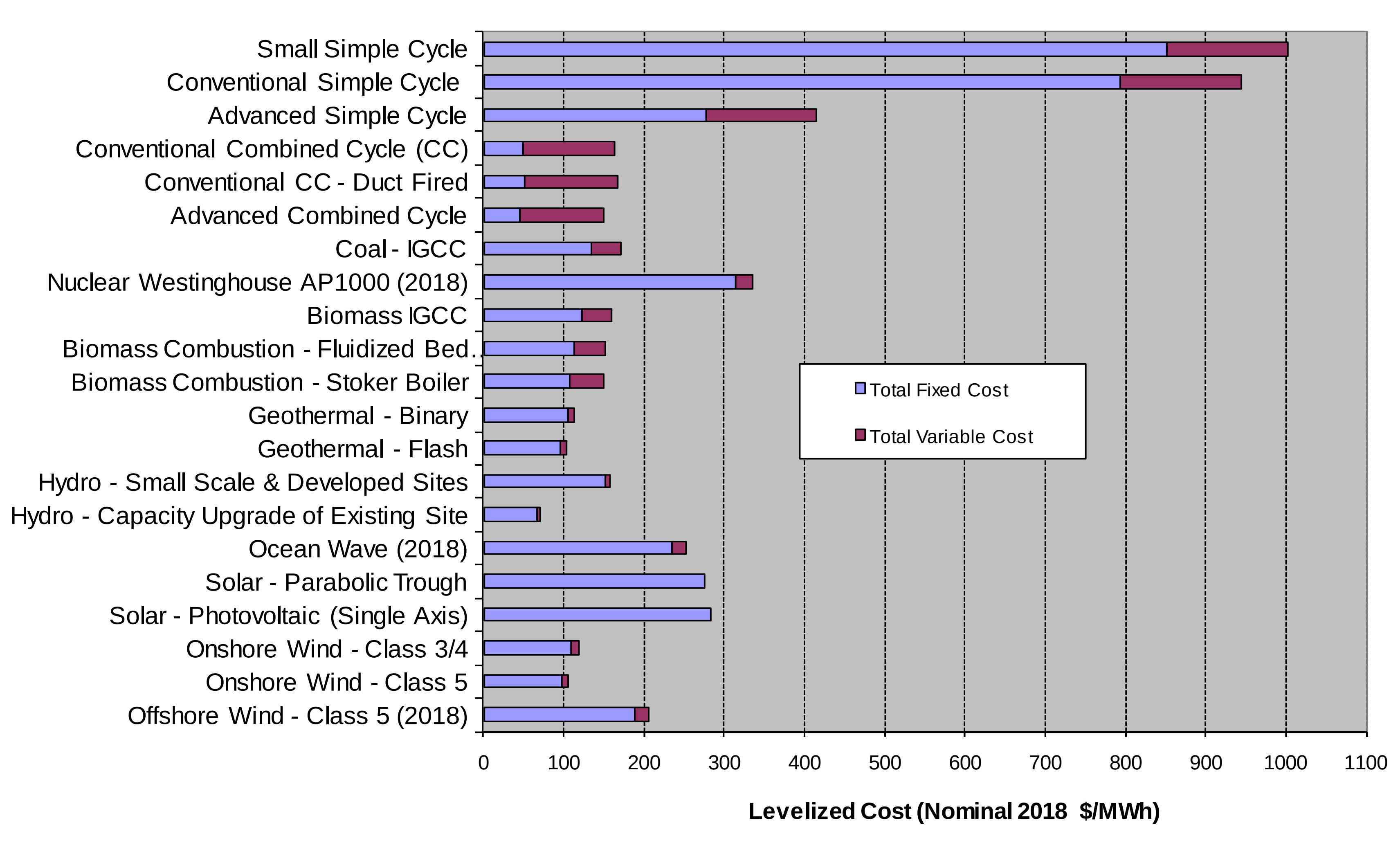
Source: Energy Commission

Table 7: Average Levelized Cost Components for In-Service in 2018—Merchant Plants

		$/MWh (Nominal $)									
In-Service Year = 2018 (Nominal 2018 $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Transmission Cost**
Small Simple Cycle	49.9	554.87	26.89	36.69	79.88	154.26	**852.59**	144.29	5.88	**150.17**	**6.29**
Conventional Simple Cycle	100	528.71	25.62	34.96	58.14	147.34	**794.76**	144.29	5.88	**150.17**	**6.29**
Advanced Simple Cycle	200	182.65	8.85	12.08	22.53	50.93	**277.04**	133.14	5.33	**138.47**	**6.29**
Conventional Combined Cycle (CC)	500	32.95	1.59	2.17	1.93	10.83	**49.46**	108.82	4.74	**113.56**	**6.25**
Conventional CC - Duct Fired	550	34.82	1.68	2.29	1.99	11.44	**52.22**	110.54	4.74	**115.29**	**6.25**
Advanced Combined Cycle	800	29.82	1.44	1.96	1.59	9.80	**44.61**	101.45	4.36	**105.81**	**6.25**
Coal - IGCC	300	86.44	4.25	5.79	11.26	26.64	**134.38**	22.92	14.38	**37.30**	**6.46**
Nuclear Westinghouse AP1000 (2018)	960	202.84	12.52	20.66	31.26	46.83	**314.11**	13.32	8.25	**21.57**	**6.73**
Biomass IGCC	30	76.15	4.41	5.85	34.94	1.77	**123.11**	31.42	6.10	**37.52**	**7.84**
Biomass Combustion - Fluidized Bed Boiler	28	77.10	4.33	5.76	21.07	5.15	**113.41**	32.13	6.99	**39.12**	**7.90**
Biomass Combustion - Stoker Boiler	38	61.57	3.47	4.60	33.19	3.99	**106.82**	32.97	10.69	**43.66**	**7.73**
Geothermal - Binary	15	101.39	7.28	11.04	13.38	-27.43	**105.67**	0.00	7.14	**7.14**	**16.61**
Geothermal - Flash	30	88.87	6.40	9.71	15.84	-24.28	**96.54**	0.00	7.94	**7.94**	**16.23**
Hydro - Small Scale & Developed Sites	15	120.08	8.07	12.23	13.32	-2.15	**151.55**	0.00	5.83	**5.83**	**7.20**
Hydro - Capacity Upgrade of Existing Site	80	50.57	3.41	5.16	9.05	-1.01	**67.18**	0.00	3.79	**3.79**	**6.82**
Ocean Wave (2018)	40	178.95	11.82	17.91	26.74	-1.09	**234.34**	0.00	18.43	**18.43**	**8.94**
Solar - Parabolic Trough	250	216.90	13.01	17.28	56.43	-26.88	**276.73**	0.00	0.00	**0.00**	**21.91**
Solar - Photovoltaic (Single Axis)	25	223.64	13.41	17.81	56.43	-27.70	**283.59**	0.00	0.00	**0.00**	**21.91**
Onshore Wind - Class 3/4	50	88.81	5.85	8.88	7.09	-0.42	**110.21**	0.00	8.37	**8.37**	**8.60**
Onshore Wind - Class 5	100	78.24	5.16	7.82	6.24	-0.37	**97.09**	0.00	8.37	**8.37**	**8.60**
Offshore Wind - Class 5 (2018)	350	152.55	10.06	15.24	11.66	-0.72	**188.79**	0.00	16.74	**16.74**	**8.63**

Source: Energy Commission

Figure 14: Average Levelized Cost Components for In-Service in 2018—Merchant Plants



Source: Energy Commission

Levelized Costs—High and Low

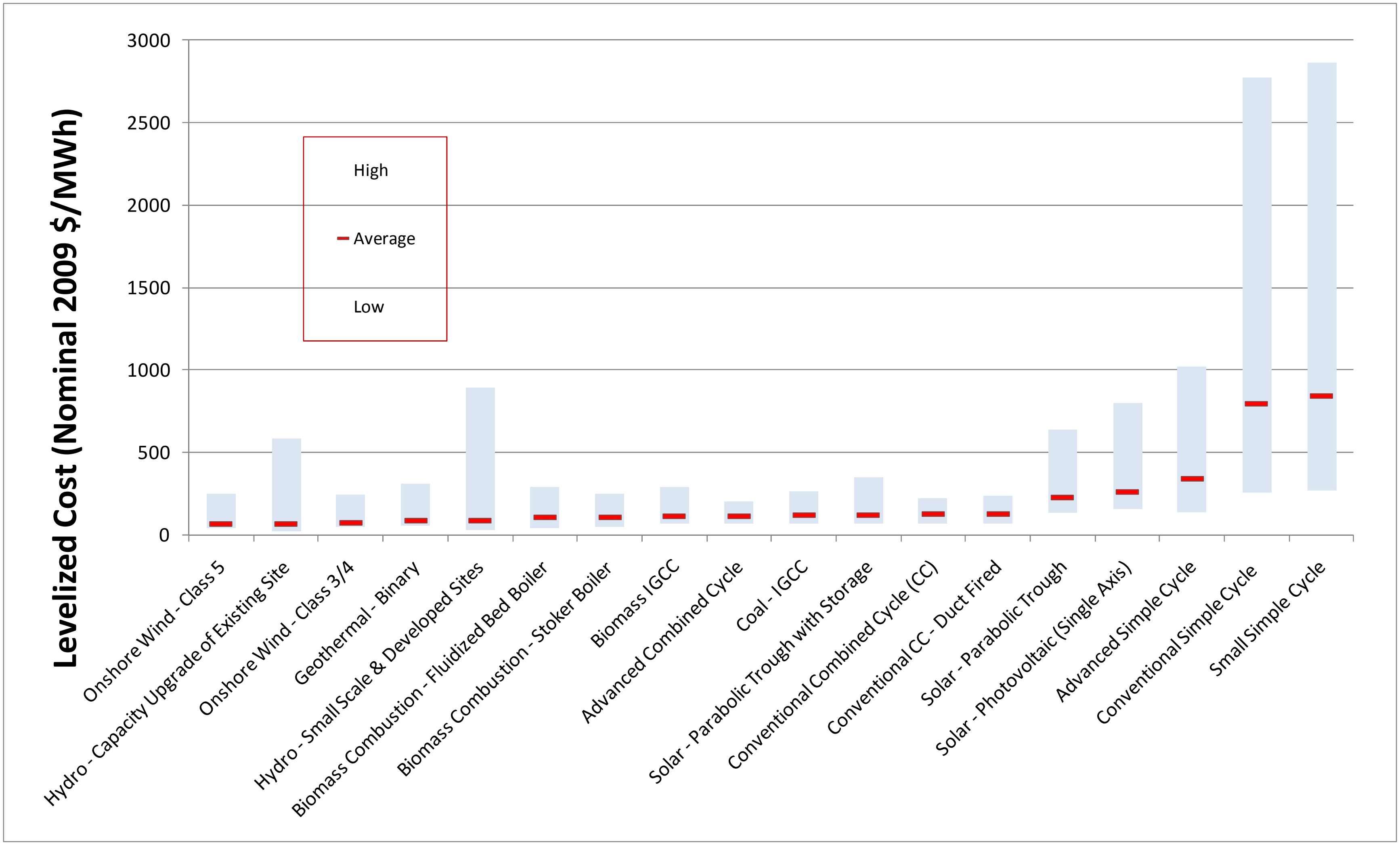
Staff provided the average levelized cost tables and graphs since this is the data that is most commonly understood and requested by various entities—and all too commonly misused. It is also important to understanding levelized costs and its various components. Relying on the average values, however, is misleading and can lead to poor decisions. These average levelized costs are based on a set of conditional assumptions that may not necessarily occur. Actual costs can vary dramatically as shown in **Figure 15**. **Figure 16** shows this same data with the vertical axis expanded to make it more readable. **Figure 17** and **Figure 18** show the same data for technologies coming on-line in 2018.

Definitions of these costs are important to understanding the figures. The average cost is based on a set of typical assumptions that are considered to be the most common values for the respective technologies. The 15 plant type and plant cost assumptions are described in Chapter 2, using the most likely set of financing and tax benefit assumptions. This can be thought of as a baseline nominal case. Each component of this average represents a most-likely-to-occur value.

The averages are a useful starting point for a more complete analysis that incorporates the full range of reasonably expected values. The high value is the maximum level that can reasonably be expected to occur. The highest plant cost and finance assumptions are relatively easy to define based on data observations. The tax benefit assumptions, which are a function of the political posture of the government, are unpredictable. The staff assumed the minimum tax benefits combined with the option of not being able to take all the tax credits in the year they occur. Similarly, the low value is the minimum level that can reasonably be expected, assuming lowest plant cost and finance assumptions that might occur, plus the most favorable tax benefits. The high and the low trends are not the extreme points that can be defined, but rather a reasonable bandwidth of costs given the current knowledge and understanding of these factors.

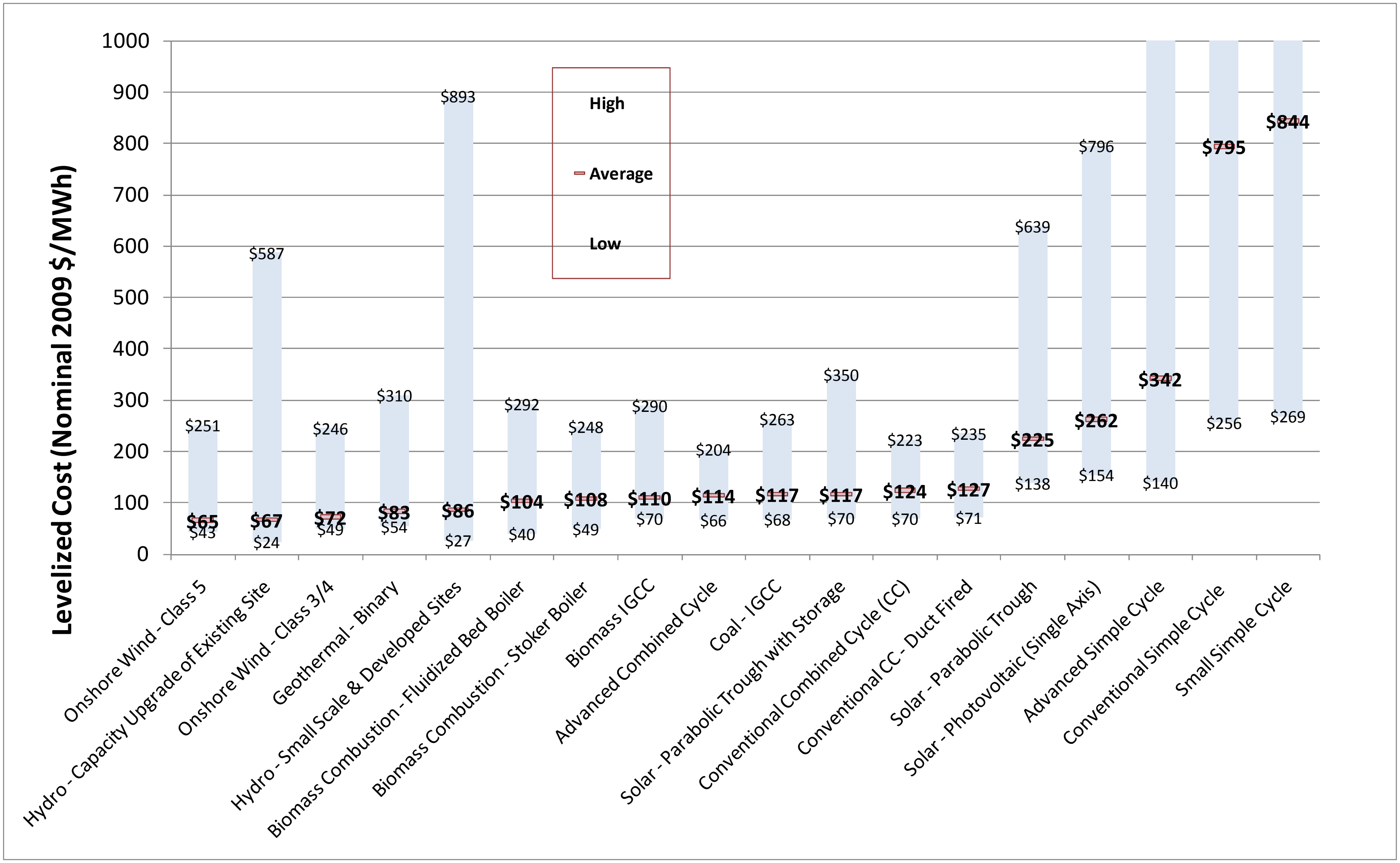
A casual examination of these figures shows that the apparent differences in average cost can be misleading in considering the range of possible costs. The high/low ranges of the conventional simple cycle units are striking and primarily reflect the range in capacity factors. In contrast, the wide range for the hydro units reflects the rather large variation in capital costs.

Figure 15: Range of Levelized Cost for a Merchant Plant In-Service in 2009



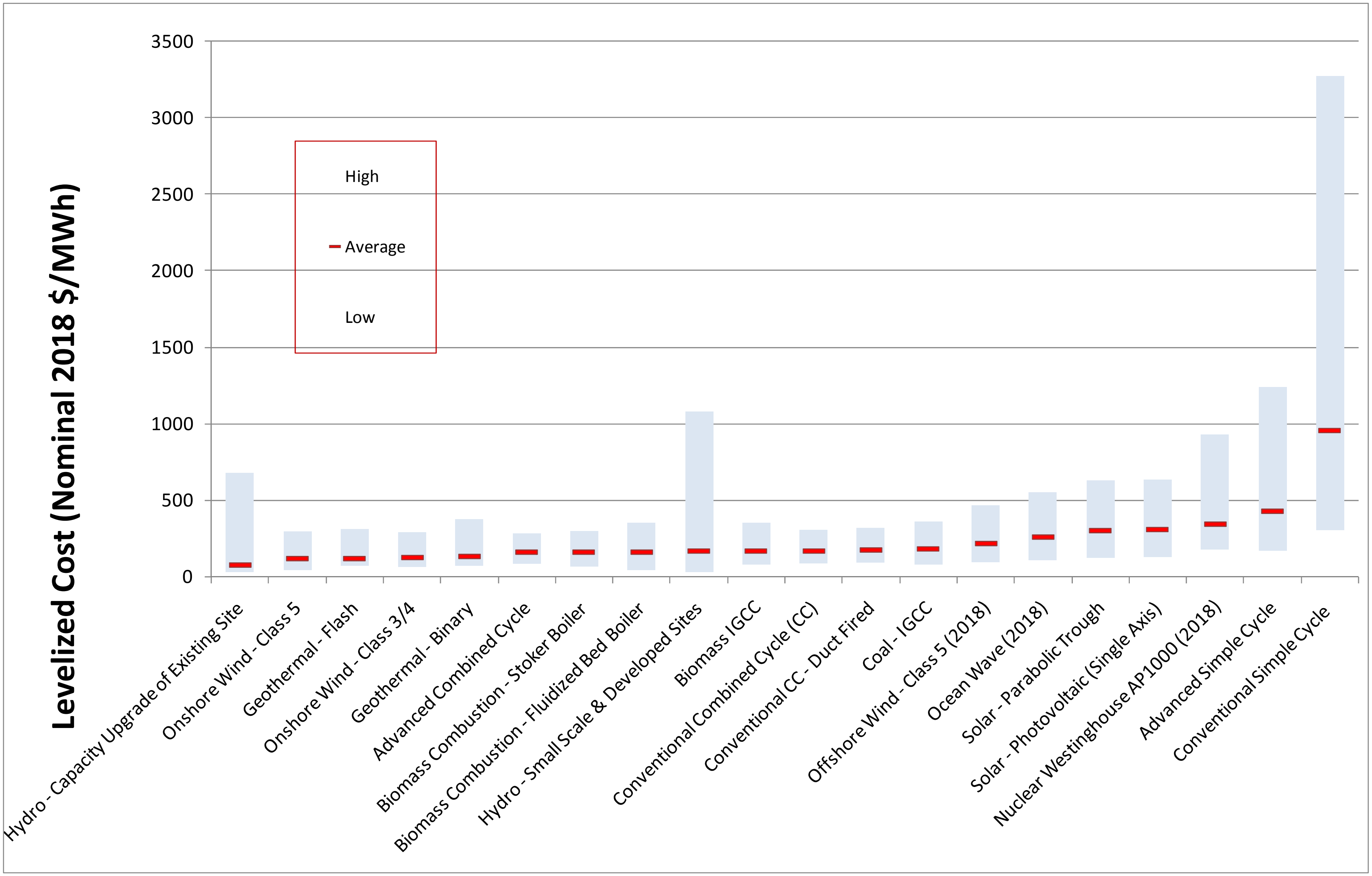
Source: Energy Commission

Figure 16: Range of Levelized Cost for a Merchant Plant In-Service in 2009—Enlarged



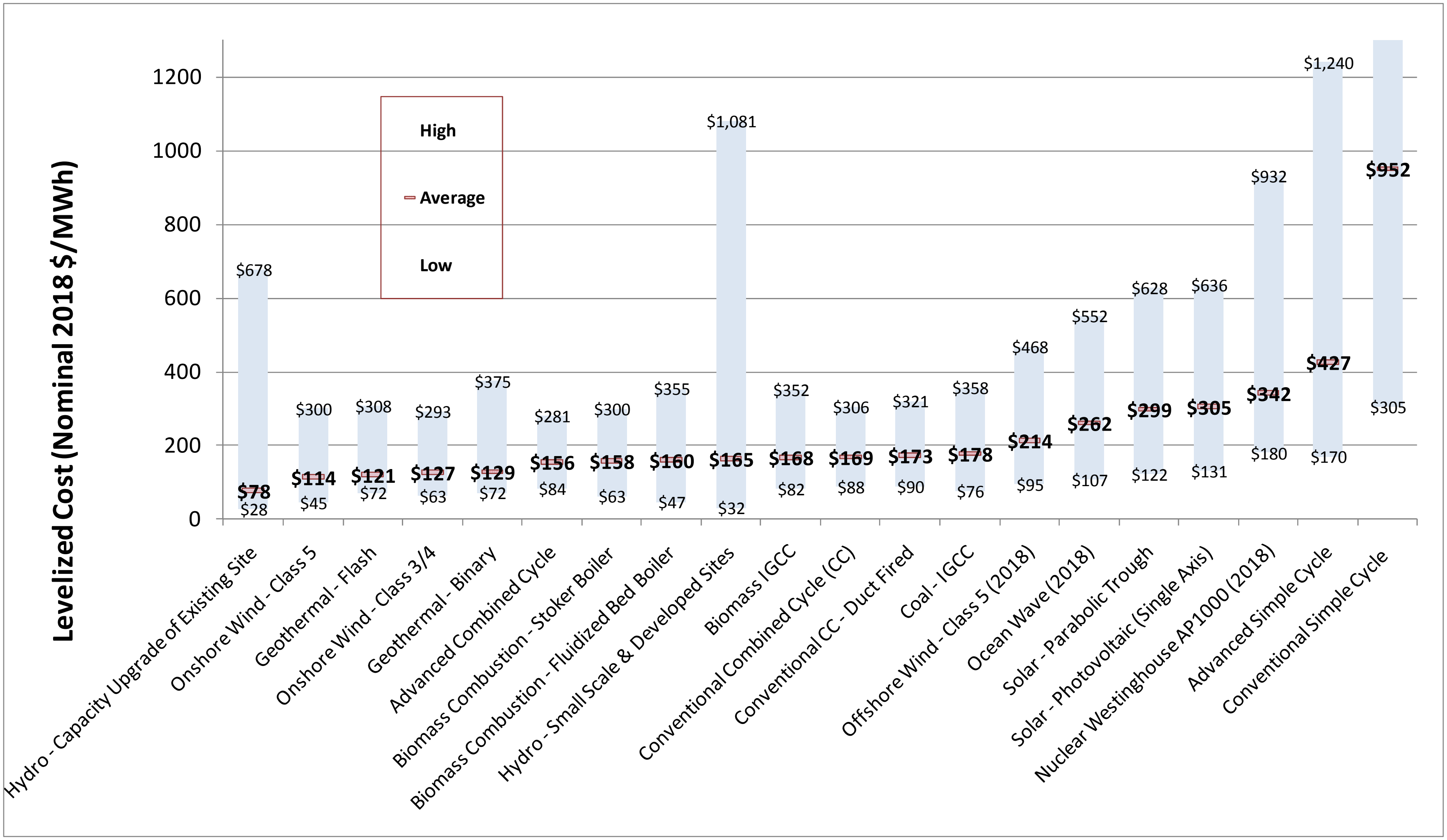
Source: Energy Commission

Figure 17: Range of Levelized Cost for Merchant Plant In-Service in 2018



Source: Energy Commission

Figure 18: Range of Levelized Cost for Merchant Plant In-Service in 2018—Enlarged



Source: Energy Commission

Effect of Tax Benefits

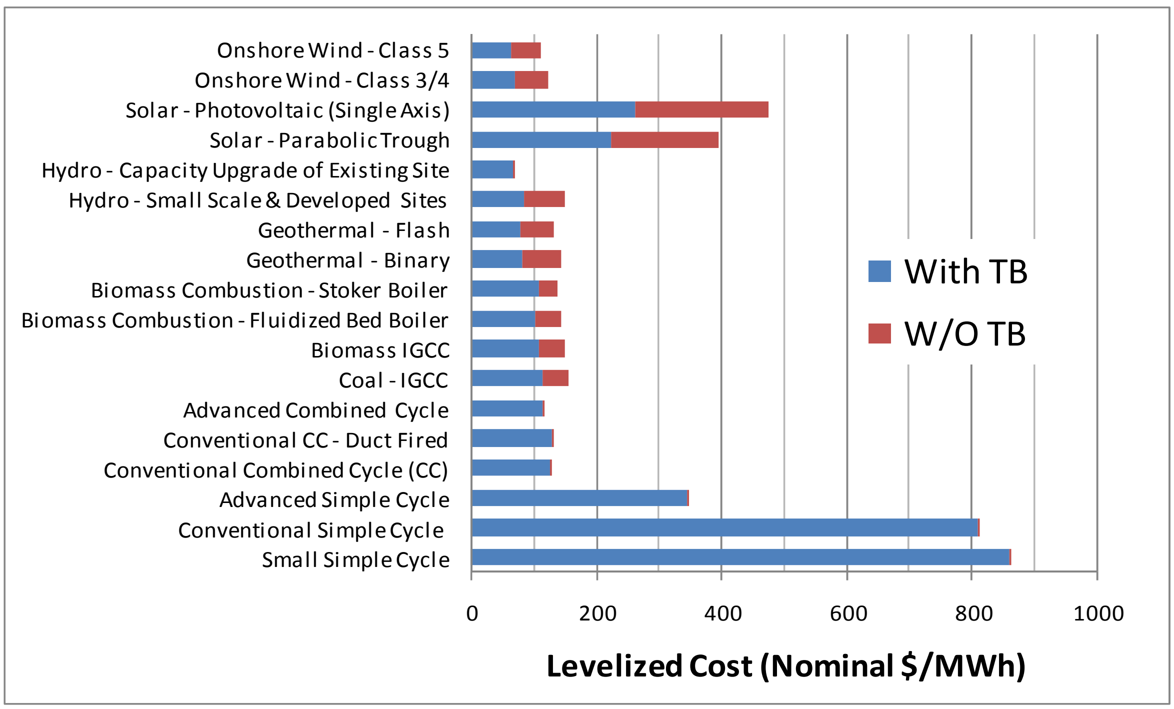
Tax benefits can have a large impact on levelized cost calculations, particularly for renewable technologies. It is important, therefore, to have a good interpretation of tax codes and uncertainty on how they may change when existing regulations expire.

Tax benefits fall into three categories:

- Accelerated depreciation
- Tax credits and tax deductions
- Property tax exemptions – for solar units only

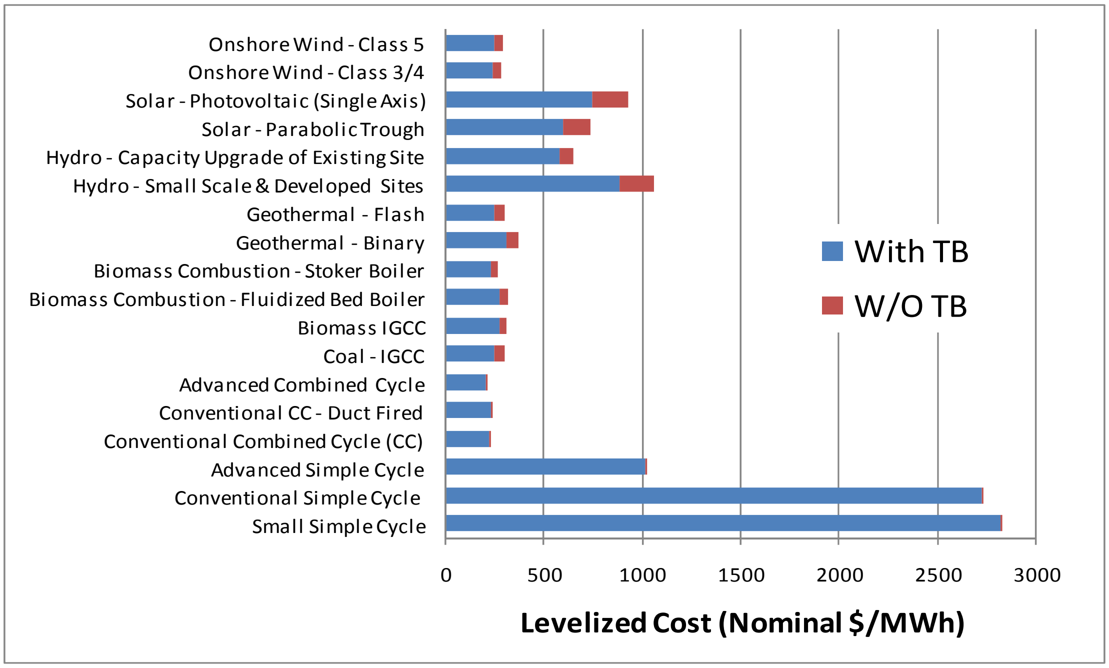
The assumptions for these tax benefits are summarized in Chapter 2. The effect of the tax benefits are shown in **Figure 19** for the Average Case, and in **Figure 20** and **Figure 21** for the High and Low Cases, respectively. All the technologies can take advantage of tax benefits, but only the renewable and alternative technologies have significant tax benefits. Solar has the largest benefits of any of the technologies.

Figure 19: Effect of Tax Benefits (TB)—Average Case



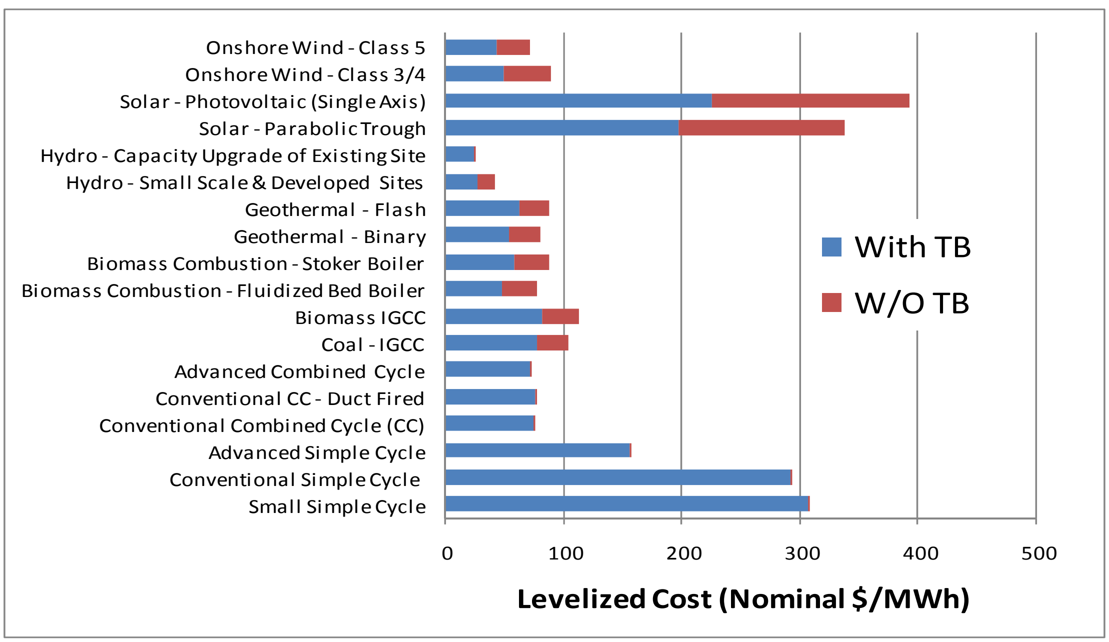
Source: Energy Commission

Figure 20: Effect of Tax Benefits (TB)—High Case



Source: Energy Commission

Figure 21: Effect of Tax Benefits (TB)—Low Case



Source: Energy Commission

Comparison to *2007 IEPR* Levelized Costs

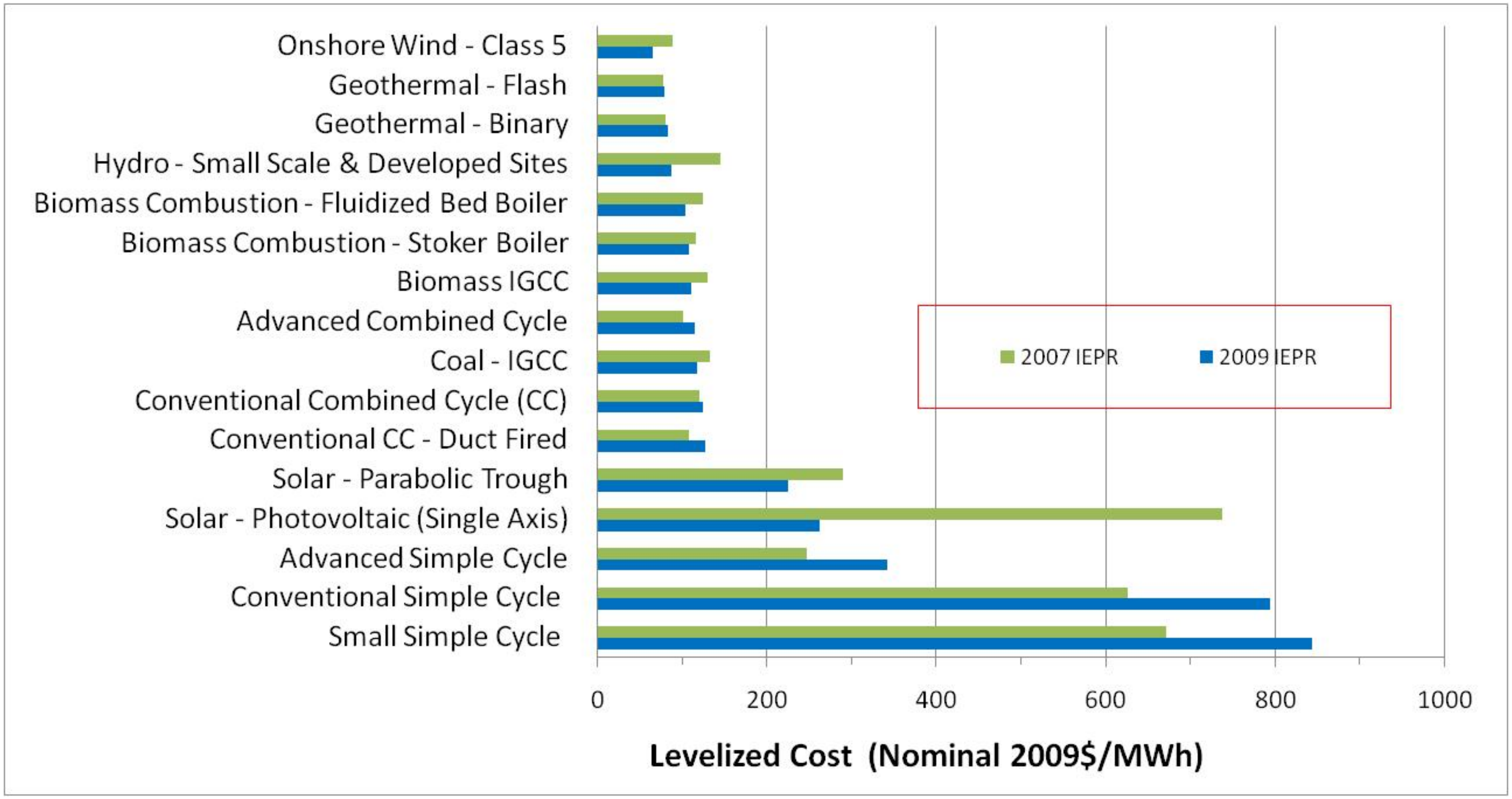
Figure 22 compares the preliminary *2009 IEPR* estimates to the *2007 IEPR* values for the in-service year 2009.

Figure 23 provides the same comparison for the in-service year 2018. These costs are highly affected by tax benefits. **Table 8** compares the change in tax benefits used for the *2009 IEPR* estimates to those in the *2007 IEPR*. **Table 9** shows the same comparison of plants with an in-service date of 2018. These tables show that the effect of tax benefits is much larger in 2009 than in 2018. Although the relationship of the various cost factors that include the tax benefits is complex, a number of worthwhile observations are noted:

- Wind Class 5 is slightly lower in cost for 2009, but by 2018 it is higher than that of the *2007 IEPR* estimates. These differences are largely from changes in the tax treatment.
- All the biomass units have lower levelized costs in 2009 but higher costs in 2018. Although the instant costs are lower, the difference is driven largely by the tax assumptions: higher in the early years, lower in the later years.
- The coal-IGCC technology shows a comparable cost to the 2007 value but would be much higher with the addition of carbon capture and sequestration (CCS) that is now required by law in California to meet the environmental performance standard. However, this increased cost is offset by higher tax credits, a decrease in the base instant cost without CCS, and the higher capacity factor assumed by KEMA (80 percent as compared to previous 60 percent).
- The geothermal technologies have slightly higher levelized costs in the early years and a much higher levelized cost in 2018. Although the instant costs are significantly higher, the difference is primarily from changes in the tax credits.
- Ocean wave has a much lower levelized cost because of a dramatic reduction in the instant cost.
- The solar trough unit shows a significant decrease in levelized cost because of lower instant costs and higher tax credits.
- The solar photovoltaic unit shows a dramatic decrease in cost in 2009, which may reflect the size difference more than cost improvement, and an even larger decrease in 2018 that is primarily from the dramatic decrease in instant cost.

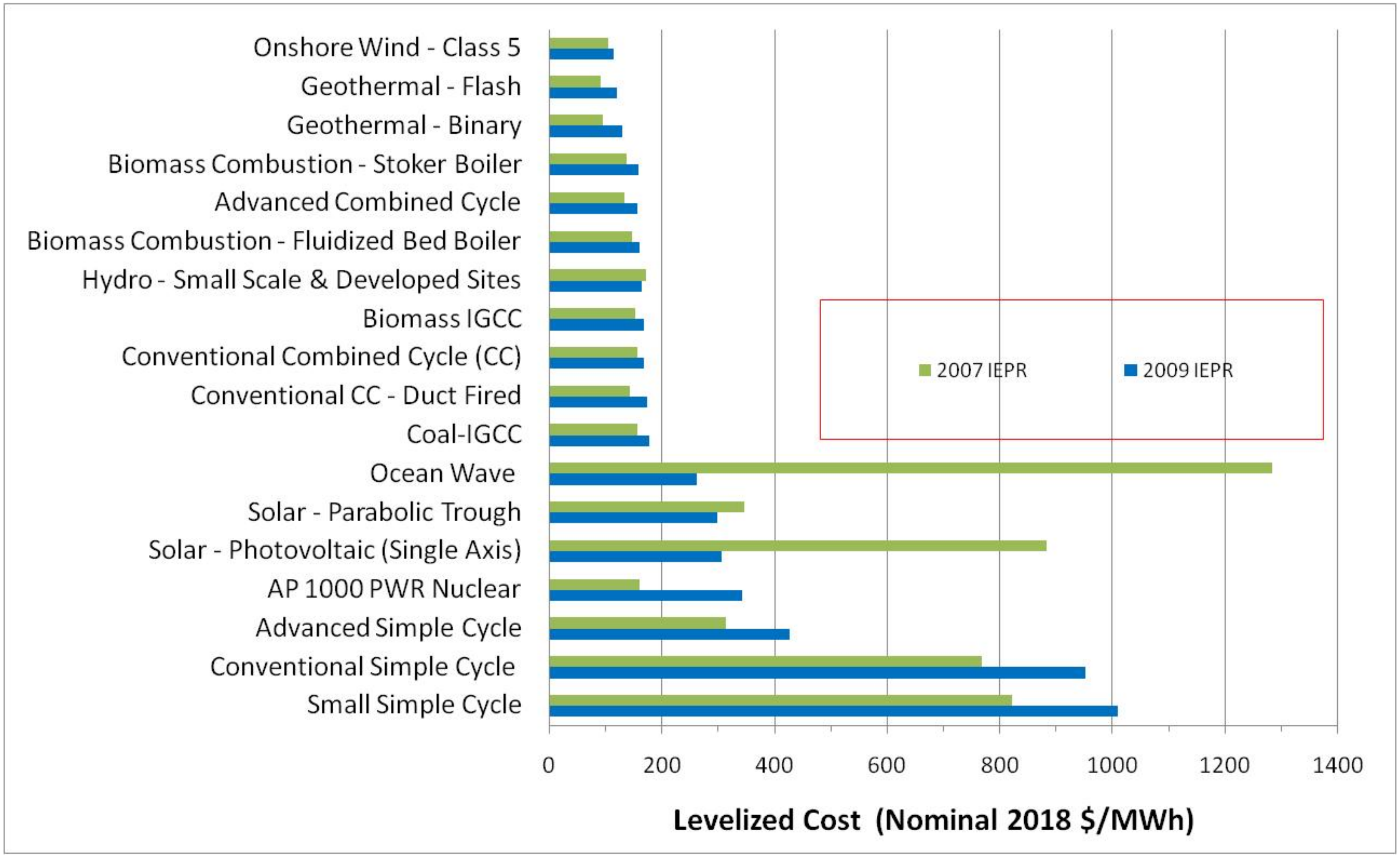
Gas-fired technologies are generally higher primarily because of the dramatic increases capital cost, as shown in **Table 10**. The effect of the increased capital cost is seen mostly in the simple cycle units, where fixed cost is the major cost component. The change in combined cycle costs is lessened due to a higher assumed capacity factor. The change in nuclear costs is partially masked by the *2007 IEPR* estimate being based on average costs, whereas the 2009 estimate reflects a more specific technology.

Figure 22: Comparing *2009 IEPR* Levelized Costs to *2007 IEPR*—In-Service in 2009



Source: Energy Commission

Figure 23: Comparing *2009 IEPR* Levelized Costs to *2007 IEPR*—In-Service in 2018



Source: Energy Commission

Table 8: *2009 IEPR* Merchant Tax Benefits vs. *2007 IEPR*—In-Service in 2009

	2009 IEPR (Nominal 2009 $/MWh)				2007 IEPR (Nominal 2009 $/MWh)			
Technology In-Service Year = 2009	Cost With Tax Benefits	Cost Without Tax Benefits	Tax Benefit	As a % of Cost w/o Tax Benefits	Cost With Tax Benefits	Cost Without Tax Benefits	Tax Benefit	As a % of Cost w/o Tax Benefits
Coal - IGCC	116.83	160.49	43.66	27%	132.72	137.07	4.36	3%
Biomass - IGCC	109.99	167.75	57.76	34%	129.19	150.31	21.12	14%
Biomass - Direct Combustion W/ Fluidized Bed	104.02	160.76	56.74	35%	123.96	155.23	31.27	20%
Biomass - Direct Combustion W/Stoker Boiler	108.25	153.67	45.42	30%	116.03	146.63	30.60	21%
Geothermal - Binary	83.11	169.99	86.88	51%	79.39	117.35	37.96	32%
Geothermal - Dual Flash	78.91	155.42	76.51	49%	77.13	114.45	37.32	33%
Hydro - Small Scale	86.47	180.53	94.06	52%	144.97	168.00	23.03	14%
Solar - Parabolic Trough	224.70	495.59	270.88	55%	289.96	376.47	86.52	23%
Solar - Photovoltaic (Single Axis)	262.21	596.47	334.26	56%	737.64	1010.02	272.38	27%
Wind - Class 5	65.47	132.31	66.84	51%	88.10	123.90	35.80	29%

Source: Energy Commission

Table 9: *2009 IEPR* Merchant Tax Benefits vs. *2007 IEPR*—In-Service in 2018

	2009 IEPR (Nominal 2018 $/MWh)				2007 IEPR (Nominal 2018 $/MWh)			
Technology In-Service Year = 2018	Cost With Tax Benefits	Cost Without Tax Benefits	Tax Benefit	As a % of Cost w/o Tax Benefits	Cost With Tax Benefits	Cost Without Tax Benefits	Tax Benefit	As a % of Cost w/o Tax Benefits
Coal - IGCC	178.14	182.08	3.94	2%	161.62	166.80	5.18	3%
AP 1000 PWR Nuclear	342.41	342.53	0.11	0%	156.70	172.45	15.76	9%
Biomass - IGCC	168.48	192.24	23.76	12%	153.92	179.01	25.09	14%
Biomass - Direct Combustion W/ Fluidized Bed	160.43	183.74	23.31	13%	147.05	184.20	37.15	20%
Biomass - Direct Combustion W/Stoker Boiler	158.22	176.93	18.71	11%	137.48	173.83	36.35	21%
Geothermal - Binary	129.42	189.62	60.20	32%	95.45	140.53	45.08	32%
Geothermal - Dual Flash	120.72	173.66	52.94	30%	92.87	137.20	44.33	32%
Hydro - Small Scale	164.59	203.17	38.58	19%	172.76	200.11	27.35	14%
Ocean - Wave (2018)	261.71	319.65	57.95	18%	1282.96	1441.32	158.35	11%
Solar - Parabolic Trough	298.64	409.85	111.21	27%	347.07	449.83	102.77	23%
Solar - Photovoltaic (Single Axis)	305.50	420.15	114.65	27%	883.24	1201.58	318.33	26%
Wind - Class 5	114.06	139.34	25.28	18%	530.30	697.96	167.66	24%

Source: Energy Commission

Table 10: Increases in instant Cost From *2007 IEPR* to *2009 IEPR*

Gas-Fired Technology In-Service Year = 2009	MW	2007 IEPR	2009 IEPR	Increase
Small Simple Cycle	49.9	$1,017	$1,292	26.95%
Conventional Simple Cycle	100	$966	$1,231	27.33%
Advanced Simple Cycle	200	$794	$827	4.12%
Conventional Combined Cycle (CC)	500	$810	$1,095	35.08%
Conventional CC - Duct Fired	550	$834	$1,080	29.56%
Advanced Combined Cycle	800	$800	$990	23.72%

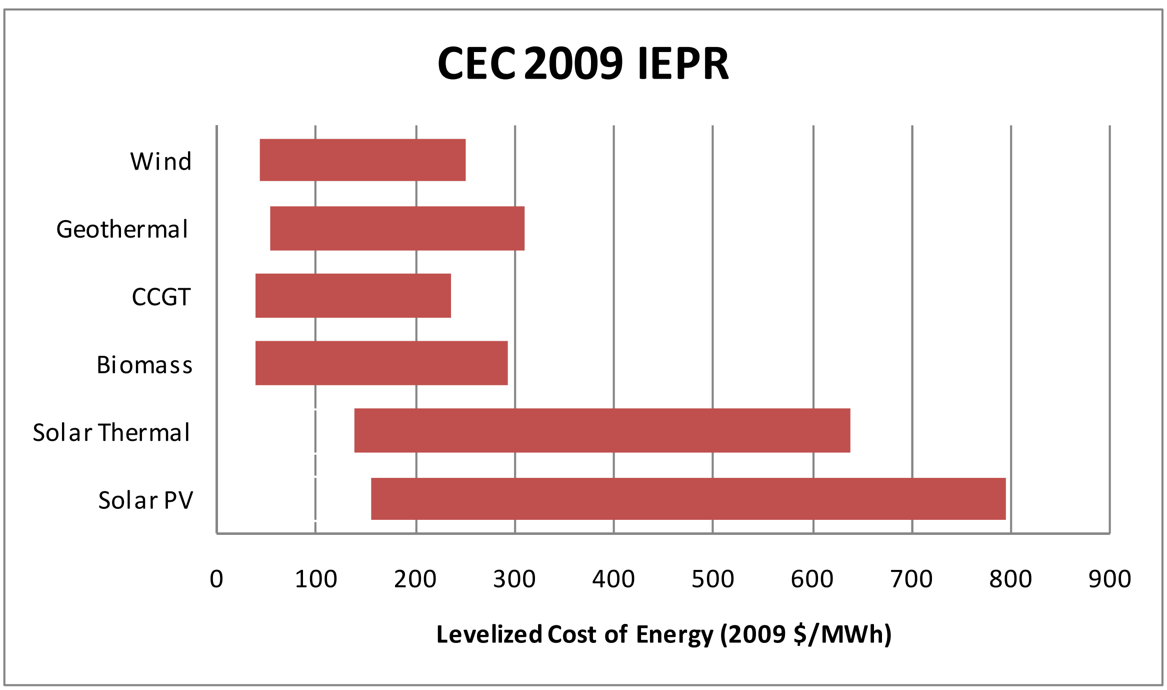
Source: Energy Commission

Comparison to CPUC 33 Percent Renewable Portfolio Standard Report

Figure 24 summarizes the range of levelized cost estimates for the *2009 IEPR* and **Figure** 25 summarizes the range of levelized costs from the draft June 2009 California Public Utilities Commission report on *33% Renewable Portfolio Standard Implementation Analysis*. In both cases, the total range of each technology cost is shown across the various configurations of that technology category.

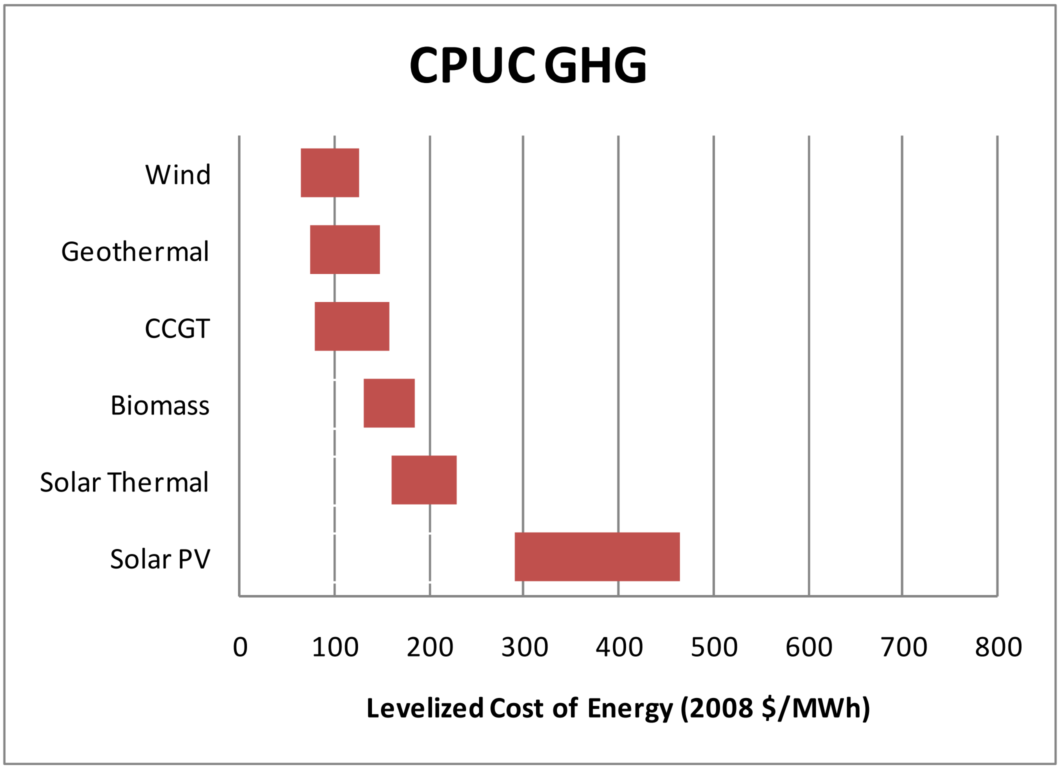
The *2009 IEPR* estimates represent a complete range of all costs, including an element of uncertainty associated with tax benefits. The CPUC range is more limited in that it represents only a range of average costs throughout the West and regions within the state. It does not reflect potential differences in costs developing over time, using a single base cost forecast and adjusting for regional and transmission investment differences. The *IEPR* ranges reflect differences in how the technologies might develop through 2018 and empirical observed ranges in similar locations. Regional differences can then be applied to these estimates for specific projects.

Figure 24: Range of Technology Costs for *2009 IEPR*



Source: Energy Commission

Figure 25: Range of Technology Costs for CPUC 33% RPS Report

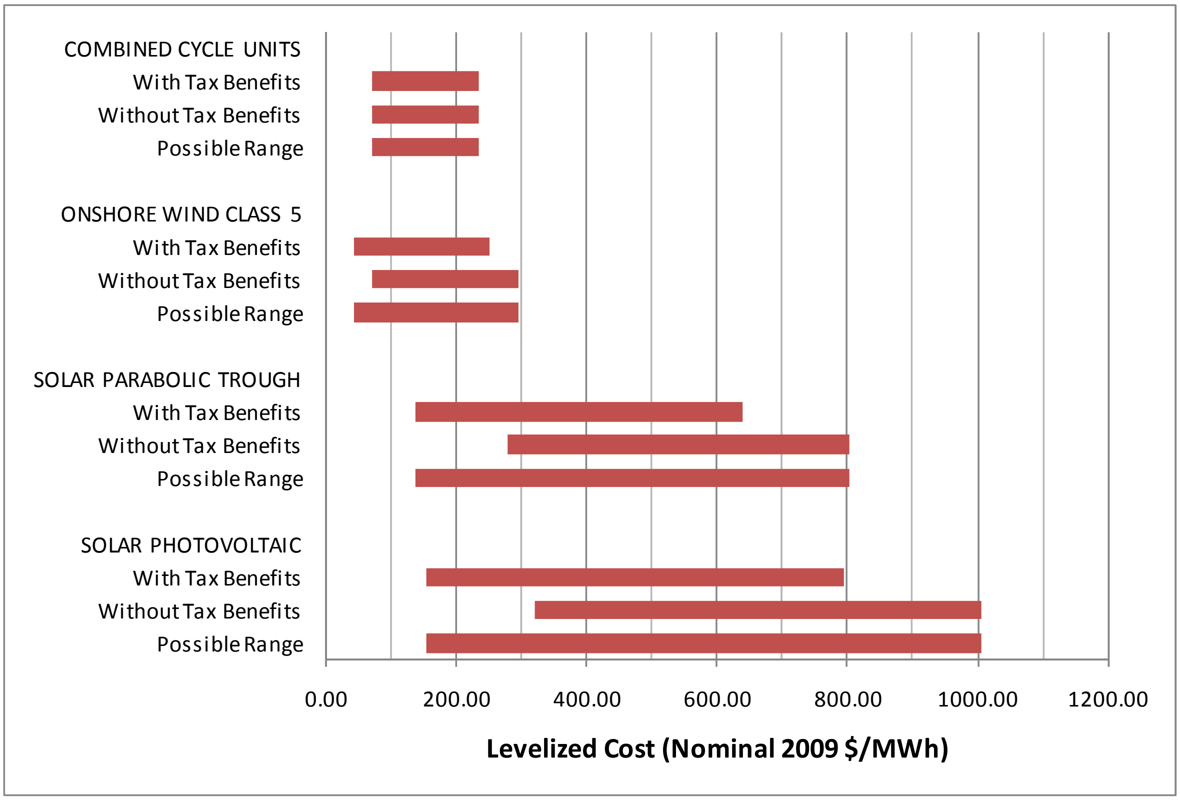


Source: June 2009 Draft CPUC 33% RPS Report

Possible Range of Levelized Costs

Figure 26 illustrates the maximum possible range of levelized costs for selected technologies. The figure shows the range of costs with and without tax benefits. The low value is the cost including tax benefits. The high value is the high cost without the tax benefits. These two points define the possible range of costs.

Figure 26: Maximum Possible Range of Levelized Costs

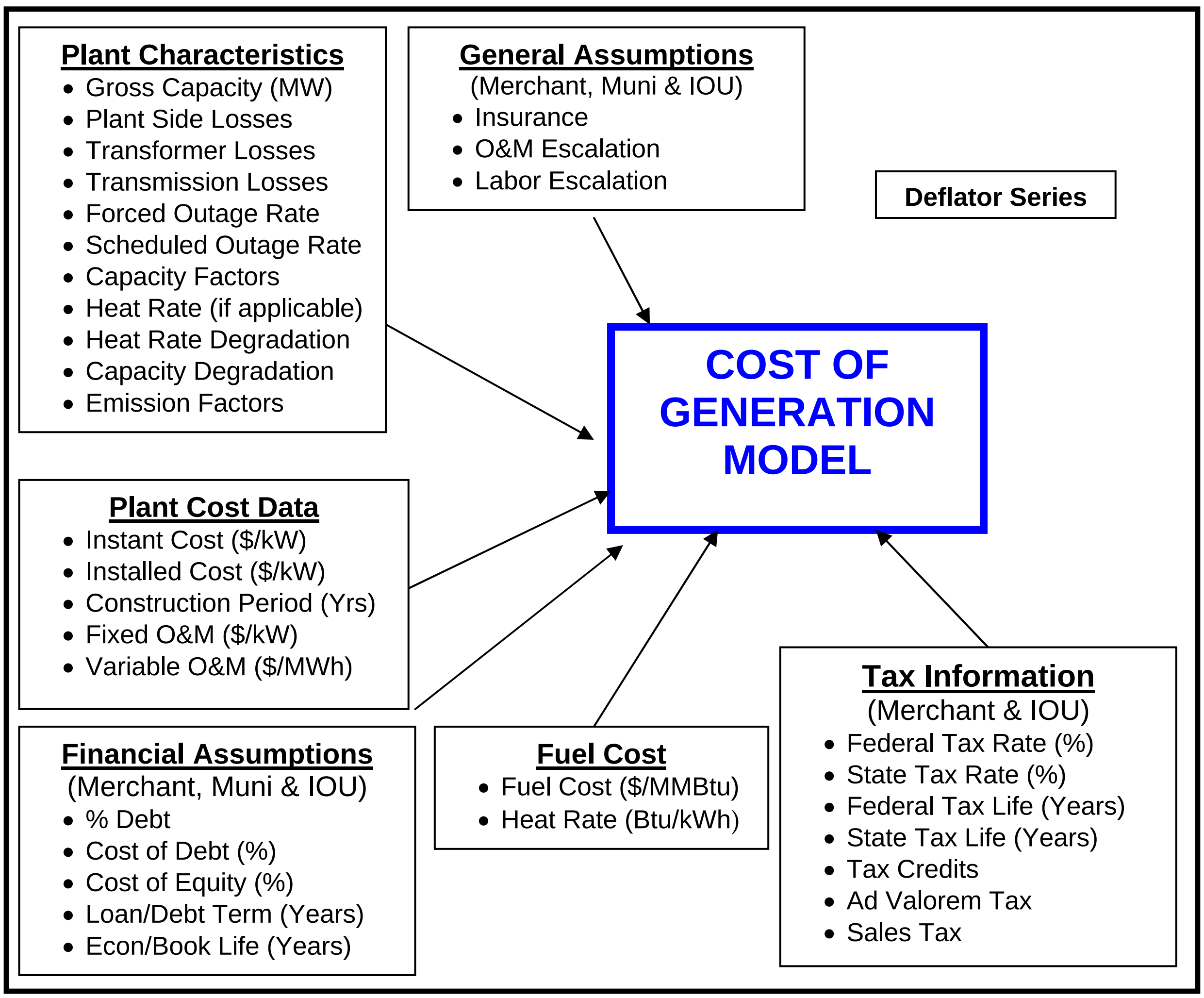


Source: Energy Commission

CHAPTER 2: Assumptions

This chapter summarizes the assumptions that were used to develop the levelized costs presented in the previous chapter. The details of these assumptions can be found in Appendix C for gas-fired generation and in the July 2009 Public Interest Energy Research (PIER) interim report *Renewable Energy Cost of Generation Update* (CEC-500-2009-084) for renewable, nuclear, and IGCC generation. **Figure 27** is a block diagram of the input assumptions.

Figure 27: Block Diagram of Input Assumptions



Source: Energy Commission

The assumptions are organized into five categories:

- Plant Data
- Plant Cost Data
- Fuel Cost and Inflation Data
- Financial Assumptions
- General Assumptions

Plant Data

Table 11 summarizes the plant data assumptions (power plant characteristics) for the average case. **Table 12** and **Table 13** summarize the same data for the high and low cases.

Gross Capacity (MW)

This is the capacity of the power plant absent plant-side losses, that is, the capacity of the power plant before accounting for the power used by the plant for operational purposes. Net Capacity is the capacity of the plant net of plant-side losses.

Plant Side Losses (Percentage)

These are sometimes defined as "parasitic losses" or "station service losses." This is the power consumed by the power plant as a part of its normal operation. It can also be defined as the difference between the gross capacity and net capacity.

Transformer Losses (Percentage)

Transformer losses are the losses in uplifting the power from the low voltage side of the transformer (generator voltage) to the high voltage side of the transformer (transmission voltage).

Transmission Losses (Percentage)

Transmission losses represent the power lost in getting the power from the high side of the transformer to the load center (sometimes designated as "GMM to Load Center").

Table 11: Plant Data—Average Case

Technology - Plant Data	Gross Capacity (MW)	Plant Side Losses	Transformer Losses	Transmission Losses	Scheduled Outage Factor	Forced Outage Rate	Capacity Factor	HHV Heat Rate (Btu/kWh)	Degradation (%/Year)		Emission Factors (Lbs/MWh)					
									Capacity	Heat Rate	NOx	VOC	CO	CO2	SOx	PM10
Small Simple Cycle	49.9	3.40%	0.50%	2.09%	2.72%	5.56%	5.00%	9,266	0.05%	0.05%	0.279	0.054	0.368	1080.2	0.013	0.134
Conventional Simple Cycle	100	3.40%	0.50%	2.09%	3.18%	4.13%	5.00%	9,266	0.05%	0.05%	0.279	0.054	0.368	1080.2	0.013	0.134
Advanced Simple Cycle	200	3.40%	0.50%	2.09%	3.18%	4.13%	10.00%	8,550	0.05%	0.05%	0.099	0.031	0.190	996.7	0.008	0.062
Conventional Combined Cycle (CC)	500	2.90%	0.50%	2.09%	6.02%	2.24%	75.00%	6,940	0.20%	0.20%	0.070	0.208	0.024	814.9	0.005	0.037
Conventional CC - Duct Fired	550	2.90%	0.50%	2.09%	6.02%	2.24%	70.00%	7,050	0.20%	0.20%	0.076	0.315	0.018	825.4	0.009	0.042
Advanced Combined Cycle	800	2.90%	0.50%	2.09%	6.02%	2.24%	75.00%	6,470	0.20%	0.20%	0.064	0.018	0.056	758.9	0.005	0.031
Coal - IGCC	300	6.00%	0.50%	2.09%	15.00%	5.00%	80.00%	7,580	0.05%	0.10%	0.220	0.009	0.079	153.2	0.063	0.031
Biomass IGCC	30	3.50%	0.50%	5.00%	3.00%	8.00%	75.00%	10,500	0.05%	0.20%	0.074	0.009	0.029	N/A	0.020	0.100
Biomass Combustion - Fluidized Bed Boiler	28	6.00%	0.50%	5.00%	3.00%	8.00%	85.00%	10,500	0.10%	0.15%	0.074	0.009	0.079	N/A	0.020	0.100
Biomass Combustion - Stoker Boiler	38	4.00%	0.50%	5.00%	3.00%	8.00%	85.00%	11,000	0.10%	0.15%	0.075	0.012	0.105	N/A	0.034	0.100
Geothermal - Binary	15	5.00%	0.50%	5.00%	4.00%	2.50%	90.00%	N/A	4.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Geothermal - Flash	30	5.00%	0.50%	5.00%	4.00%	2.50%	94.00%	N/A	4.00%	N/A	0.191	0.011	0.058	N/A	0.026	0.000
Hydro - Small Scale & Developed Sites	15	10.00%	0.50%	5.00%	9.40%	5.10%	30.40%	N/A	2.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Hydro - Capacity Upgrade of Existing Site	80	5.00%	0.50%	5.00%	9.40%	5.10%	30.40%	N/A	2.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Parabolic Trough	250	22.40%	0.50%	5.00%	2.20%	1.60%	27.00%	N/A	0.50%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Photovoltaic (Single Axis)	25	22.40%	0.50%	5.00%	0.00%	2.00%	27.00%	N/A	0.50%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 3/4	50	0.10%	0.50%	5.00%	1.39%	2.00%	37.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 5	100	0.10%	0.50%	5.00%	1.39%	2.00%	42.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A

Source: Energy Commission

Table 12: Plant Data—High Case

Technology - Plant Data	Gross Capacity (MW)	Plant Side Losses	Transformer Losses	Transmission Losses	Scheduled Outage Factor	Forced Outage Rate	Capacity Factor	HHV Heat Rate Btu/kWh	Degradation (%/Year)		Emission Factors (Lbs/MWh)					
									Capacity	Heat Rate	NOx	VOC	CO	CO2	SOx	PM10
Small Simple Cycle	49.9	4.20%	0.50%	2.09%	2.72%	5.56%	2.50%	10,000	0.05%	0.20%	0.279	0.054	0.368	1165.8	0.013	0.134
Conventional Simple Cycle	100	4.20%	0.50%	2.09%	3.18%	4.13%	2.50%	10,000	0.05%	0.20%	0.279	0.054	0.368	1165.8	0.013	0.134
Advanced Simple Cycle	200	4.20%	0.50%	2.09%	3.18%	4.13%	5.00%	8,700	0.05%	0.20%	0.099	0.031	0.190	1014.2	0.008	0.062
Conventional Combined Cycle (CC)	500	4.00%	0.50%	2.09%	6.02%	2.24%	55.00%	7,200	0.20%	0.20%	0.070	0.208	0.024	839.4	0.005	0.037
Conventional CC - Duct Fired	550	4.00%	0.50%	2.09%	6.02%	2.24%	50.00%	7,400	0.20%	0.20%	0.076	0.315	0.018	862.7	0.009	0.042
Advanced Combined Cycle	800	4.00%	0.50%	2.09%	6.02%	2.24%	55.00%	6,710	0.20%	0.20%	0.064	0.018	0.056	782.2	0.005	0.031
Coal - IGCC	300	7.00%	0.50%	2.09%	22.50%	7.50%	70.00%	8,025	0.10%	0.20%	0.314	0.009	0.079	163.1	0.094	0.031
Biomass IGCC	30	4.50%	0.50%	5.00%	6.00%	10.00%	60.00%	11,000	0.10%	0.25%	0.074	0.009	0.029	N/A	0.020	0.200
Biomass Combustion - Fluidized Bed Boiler	28	7.00%	0.50%	5.00%	6.00%	10.00%	75.00%	11,000	0.20%	0.20%	0.074	0.009	0.079	N/A	0.020	0.200
Biomass Combustion - Stoker Boiler	38	7.00%	0.50%	5.00%	6.00%	10.00%	75.00%	13,500	0.20%	0.20%	0.075	0.012	0.105	N/A	0.034	0.200
Geothermal - Binary	15	10.00%	0.50%	5.00%	12.00%	2.80%	80.00%	N/A	4.00%	N/A	0.000	0.000	0.000	N/A	0.000	0.000
Geothermal - Flash	30	5.00%	0.50%	5.00%	12.00%	2.80%	90.00%	N/A	4.00%	N/A	0.191	0.011	0.058	N/A	0.026	0.000
Hydro - Small Scale & Developed Sites	15	13.00%	0.50%	5.00%	9.56%	6.70%	12.50%	N/A	2.25%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Hydro - Capacity Upgrade of Existing Site	80	15.00%	0.50%	5.00%	9.56%	6.70%	12.50%	N/A	2.25%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Parabolic Trough	250	24.00%	0.50%	5.00%	4.20%	1.60%	26.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Photovoltaic (Single Axis)	25	24.00%	0.50%	5.00%	0.00%	8.00%	26.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 3/4	50	0.10%	0.50%	5.00%	1.83%	2.70%	41.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 5	100	0.10%	0.50%	5.00%	1.83%	2.70%	40.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A

Source: Energy Commission

Table 13: Plant Data—Low Case

Technology - Plant Data	Gross Capacity (MW)	Plant Side Losses	Transformer Losses	Transmission Losses	Scheduled Outage Factor	Forced Outage Rate	Capacity Factor	HHV Heat Rate (Btu/kWh)	Degradation (%/Year)		Emission Factors (Lbs/MWh)					
									Capacity	Heat Rate	NOx	VOC	CO	CO2	SOx	PM10
Small Simple Cycle	49.9	2.30%	0.50%	2.09%	2.72%	5.56%	10.00%	9,020	0.05%	0.05%	0.279	0.054	0.368	1051.5	0.013	0.134
Conventional Simple Cycle	100	2.30%	0.50%	2.09%	3.18%	4.13%	10.00%	9,020	0.05%	0.05%	0.279	0.054	0.368	1051.5	0.013	0.134
Advanced Simple Cycle	200	2.30%	0.50%	2.09%	3.18%	4.13%	20.00%	8,230	0.05%	0.05%	0.099	0.031	0.190	959.4	0.008	0.062
Conventional Combined Cycle (CC)	500	2.00%	0.50%	2.09%	6.02%	2.24%	90.00%	6,600	0.20%	0.20%	0.070	0.208	0.024	769.4	0.005	0.037
Conventional CC - Duct Fired	550	2.00%	0.50%	2.09%	6.02%	2.24%	85.00%	6,700	0.20%	0.20%	0.076	0.315	0.018	781.1	0.009	0.042
Advanced Combined Cycle	800	2.00%	0.50%	2.09%	6.02%	2.24%	90.00%	6,310	0.20%	0.20%	0.064	0.018	0.056	735.6	0.005	0.031
Coal - IGCC	300	5.00%	0.50%	2.09%	7.50%	2.50%	90.00%	7,100	0.00%	0.10%	0.126	0.009	0.079	143.3	0.031	0.031
Biomass IGCC	30	2.50%	0.50%	2.09%	2.00%	6.00%	85.00%	10,000	0.00%	0.15%	0.074	0.009	0.029	N/A	0.020	0.025
Biomass Combustion - Fluidized Bed Boiler	28	5.00%	0.50%	2.09%	2.00%	6.00%	90.00%	9,800	0.00%	0.10%	0.074	0.009	0.079	N/A	0.020	0.025
Biomass Combustion - Stoker Boiler	38	2.40%	0.50%	2.09%	2.00%	6.00%	90.00%	10,250	0.00%	0.10%	0.075	0.012	0.105	N/A	0.034	0.025
Geothermal - Binary	15	5.00%	0.50%	2.09%	2.00%	2.20%	95.00%	N/A	4.00%	N/A	0.000	0.000	0.000	N/A	0.000	0.000
Geothermal - Flash	30	5.00%	0.50%	2.09%	2.00%	2.20%	98.00%	N/A	4.00%	N/A	0.191	0.011	0.058	N/A	0.026	0.000
Hydro - Small Scale & Developed Sites	15	9.20%	0.50%	2.09%	9.20%	3.80%	61.50%	N/A	1.75%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Hydro - Capacity Upgrade of Existing Site	80	5.00%	0.50%	2.09%	9.20%	3.80%	61.50%	N/A	1.75%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Parabolic Trough	250	20.40%	0.50%	2.09%	2.20%	1.60%	28.00%	N/A	0.25%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Solar - Photovoltaic (Single Axis)	25	20.00%	0.50%	2.09%	0.00%	1.00%	28.00%	N/A	0.25%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 3/4	50	0.10%	0.50%	2.09%	0.96%	1.30%	34.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A
Onshore Wind - Class 5	100	0.10%	0.50%	2.09%	0.96%	1.30%	44.00%	N/A	1.00%	N/A	0.000	0.000	0.000	N/A	N/A	N/A

Source: Energy Commission

Schedule Outage Factor (SOF)

This is a term developed by the North American Reliability Council's (NERC)[5] Generating Availability Data System (GADS).[6] The NERC/GADS term is used to define the maintenance period. SOF is the ratio of scheduled outage hours (SOH) to the period hours (PH), typically 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 scheduled maintenance, then its SOF is 10 percent. This is generally synonymous with the commonly misused modeling term maintenance outage rate (MOR). The formula for this measure is:

SOF = SOH/PH

Forced Outage Rate (FOR)

This is a NERC/GADS term to measure a power plant's rate of failure. This calculation ignores the period during reserve shutdown (economic shutdown). The FOR is based solely on when it is called upon to be dispatched. The simplified GADS formula for this measure is:

FOR = FOH / (FOH + SH)

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

SH = Service Hours (Hours of Successful Operation)

This is a commonly used characterization but is very simplified since a power plant can have a partial failure and operate at reduced power. The more precise term is equivalent FOR (EFOR), which includes other plant variables. EFOR is relevant for analyzing the performance of operating power plants. However, it should be understood that where EFOR data is available, it is applied to the Model. For simplicity, the term FOR is used in the Model, with the understanding that the appropriate value is really EFOR.

Capacity Factor (Percentage)

The capacity factor (CF) is specified as a percentage and is a measure of how much the power plant operates. More precisely, it is equal to the energy generated by the power plant during the year divided by the energy it could have generated if it had run at its full capacity throughout the entire year (Gross MW x 8,760 hours). For a solar plant, the gross MW are measured at the DC level, as opposed to AC level.

---

[5] NERC was developed as a result of the Northeast blackout on November 9, 1965. It is a non-profit organization that was created in 1968 to improve the reliability of the electric system.

[6] NERC recognized the need to gather data to be effective in proposing reliability measures and created GADS in 1979.

Heat Rate (Btu/kWh)

Heat rates are a measure of the efficiency of power plants. It is the amount of heat supplied in British thermal units (Btu) 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).

Capacity Degradation Factor (Percentage)

This is the percentage that the gross capacity will decrease each year from wear and tear, which affects not only the capacity, but also the energy generation. This is reflected in the energy calculation in the Model. This degradation can be partially offset by maintenance, such that a true characterization would have an up and down characterization that trends generally downward. The fluctuation reflects the wear and tear, followed by an improved period. The factor used herein is an equivalent constant annual amount that reflects both the net effect of the deterioration and maintenance periods.

Heat Rate Degradation Factor (Percentage)

Heat rate degradation is a measure of the decrease in efficiency due to aging. It is the percentage that the heat rate will increase per year. Similar to capacity degradation, it fluctuates up and down, generally trending downward. The percentage used herein is an equivalent annual amount that reflects both the net effect of the deterioration and maintenance periods.

Plant Cost Data

Table 14 summarizes the data for the average case. Since the ocean wave and offshore wind technologies do not become feasible until 2018, the data shown here are the 2018 costs deflated to 2009 dollars. **Table 15** and **Table 16** summarize the corresponding high and low cases.

Table 14: Plant Cost Data—Average Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	1,277	15	1,292	100%	0%	0%	0%	0%	0%	23.94	4.17
Conventional Simple Cycle	100	1,204	27	1,231	100%	0%	0%	0%	0%	0%	17.40	4.17
Advanced Simple Cycle	200	801	26	827	75%	25%	0%	0%	0%	0%	16.33	3.67
Conventional Combined Cycle (CC)	500	1,044	51	1,095	75%	25%	0%	0%	0%	0%	8.62	3.02
Conventional CC - Duct Fired	550	1,021	59	1,080	75%	25%	0%	0%	0%	0%	8.30	3.02
Advanced Combined Cycle	800	957	33	990	75%	25%	0%	0%	0%	0%	7.17	2.69
Coal - IGCC	300	3,128	56	3,184	80%	20%	0%	0%	0%	0%	52.35	9.57
Biomass IGCC	30	2,950	47	2,997	75%	25%	0%	0%	0%	0%	150.00	4.00
Biomass Combustion - Fluidized Bed Boiler	28	3,200	54	3,254	80%	20%	0%	0%	0%	0%	99.50	4.47
Biomass Combustion - Stoker Boiler	38	2,600	58	2,658	80%	20%	0%	0%	0%	0%	160.10	6.98
Geothermal - Binary	15	4,046	0	4,046	40%	40%	20%	0%	0%	0%	47.44	4.55
Geothermal - Flash	30	3,676	42	3,718	40%	40%	20%	0%	0%	0%	58.38	5.06
Hydro - Small Scale & Developed Sites	15	1,730	0	1,730	100%	0%	0%	0%	0%	0%	17.57	3.48
Hydro - Capacity Upgrade of Existing Site	80	771	0	771	100%	0%	0%	0%	0%	0%	12.59	2.39
Solar - Parabolic Trough	250	3,687	0	3,687	100%	0%	0%	0%	0%	0%	68.00	0.00
Solar - Photovoltaic (Single Axis)	25	4,550	0	4,550	100%	0%	0%	0%	0%	0%	68.00	0.00
Onshore Wind - Class 3/4	50	1,990	0	1,990	95%	5%	0%	0%	0%	0%	13.70	5.50
Onshore Wind - Class 5	100	1,990	0	1,990	95%	5%	0%	0%	0%	0%	13.70	5.50

Source: Energy Commission

Table 15: Plant Cost Data—High Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	1,567	11	1,578	75%	25%	0%	0%	0%	0%	42.44	9.05
Conventional Simple Cycle	100	1,495	23	1,518	75%	25%	0%	0%	0%	0%	42.44	9.05
Advanced Simple Cycle	200	919	23	942	50%	40%	10%	0%	0%	0%	39.82	8.05
Conventional Combined Cycle (CC)	500	1,349	40	1,389	50%	40%	10%	0%	0%	0%	12.62	3.84
Conventional CC - Duct Fired	550	1,325	45	1,370	50%	40%	10%	0%	0%	0%	12.62	3.84
Advanced Combined Cycle	800	1,218	27	1,245	50%	40%	10%	0%	0%	0%	10.97	3.42
Coal - IGCC	300	3,892	66	3,957	60%	40%	0%	0%	0%	0%	65.33	11.95
Biomass IGCC	30	3,688	63	3,751	50%	40%	10%	0%	0%	0%	175.00	4.50
Biomass Combustion - Fluidized Bed Boiler	28	4,800	80	4,880	60%	40%	0%	0%	0%	0%	150.00	10.00
Biomass Combustion - Stoker Boiler	38	3,250	83	3,333	50%	40%	10%	0%	0%	0%	200.00	8.73
Geothermal - Binary	15	5,881	0	5,881	45%	45%	10%	0%	0%	0%	54.65	5.12
Geothermal - Flash	30	5,279	41	5,320	45%	45%	10%	0%	0%	0%	67.14	5.28
Hydro - Small Scale & Developed Sites	15	2,770	0	2,770	35%	40%	25%	0%	0%	0%	28.83	5.54
Hydro - Capacity Upgrade of Existing Site	80	1,638	0	1,638	35%	40%	25%	0%	0%	0%	27.05	5.00
Solar - Parabolic Trough	250	3,900	0	3,900	100%	0%	0%	0%	0%	0%	92.00	0.00
Solar - Photovoltaic (Single Axis)	25	5,005	0	5,005	100%	0%	0%	0%	0%	0%	92.00	0.00
Onshore Wind - Class 3/4	50	3,025	0	3,025	45%	45%	10%	0%	0%	0%	17.13	7.66
Onshore Wind - Class 5	100	3,025	0	3,025	45%	45%	10%	0%	0%	0%	17.13	7.66

Source: Energy Commission

Table 16: Plant Cost Data—Low Case

Plant Cost Data Start Year = 2009 (2009 Dollars)	Gross Capacity (MW)	Instant Costs ($/kW)			Construction Period (%/Year)						Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
		Base	Environmental Compliance	Total	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5		
Small Simple Cycle	49.9	914	21	935	100%	0%	0%	0%	0%	0%	6.68	0.88
Conventional Simple Cycle	100	842	33	875	100%	0%	0%	0%	0%	0%	6.68	0.88
Advanced Simple Cycle	200	693	31	724	100%	0%	0%	0%	0%	0%	6.27	0.79
Conventional Combined Cycle (CC)	500	777	59	836	100%	0%	0%	0%	0%	0%	5.76	2.19
Conventional CC - Duct Fired	550	753	69	822	100%	0%	0%	0%	0%	0%	5.76	2.19
Advanced Combined Cycle	800	759	37	796	100%	0%	0%	0%	0%	0%	5.01	1.95
Coal - IGCC	300	2,356	42	2,398	80%	20%	0%	0%	0%	0%	39.79	7.17
Biomass IGCC	30	2,655	26	2,681	100%	0%	0%	0%	0%	0%	125.00	3.00
Biomass Combustion - Fluidized Bed Boiler	28	1,600	29	1,629	100%	0%	0%	0%	0%	0%	70.00	3.00
Biomass Combustion - Stoker Boiler	38	1,750	32	1,782	90%	10%	0%	0%	0%	0%	107.80	4.70
Geothermal - Binary	15	2,318	0	2,318	40%	40%	20%	0%	0%	0%	40.32	4.31
Geothermal - Flash	30	2,534	44	2,578	35%	35%	30%	0%	0%	0%	49.62	4.85
Hydro - Small Scale & Developed Sites	15	945	0	945	100%	0%	0%	0%	0%	0%	9.88	1.90
Hydro - Capacity Upgrade of Existing Site	80	514	0	514	100%	0%	0%	0%	0%	0%	8.77	1.60
Solar - Parabolic Trough	250	3,408	0	3,408	100%	0%	0%	0%	0%	0%	60.00	0.00
Solar - Photovoltaic (Single Axis)	25	4,095	0	4,095	100%	0%	0%	0%	0%	0%	60.00	0.00
Onshore Wind - Class 3/4	50	1,440	0	1,440	90%	10%	0%	0%	0%	0%	10.28	4.82
Onshore Wind - Class 5	100	1,440	0	1,440	90%	10%	0%	0%	0%	0%	10.28	4.82

Source: Energy Commission

Instant Cost

Instant cost, sometimes referred to as overnight cost, is the initial capital expenditure. The instant costs do not include the costs incurred during construction (see installed cost). Instant costs include all costs: the component cost, land cost, development cost, permitting cost, connection equipment such as transmission, and environmental control costs.

Installed Cost

Installed cost is 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, sales taxes, and the costs associated with escalation of costs during construction.

Construction Period

The construction costs depend on the number of years to build the power plant since the loan period is increased. Year 0 is the last year of construction, and for a 5-year construction period. Year 5 would be the first year.

Fixed Operations and Maintenance Cost

Conceptually, fixed O&M comprises those costs that occur regardless of how much the plant operates. The costs included in this category are not always consistent from one assessment to the other but always include labor and the associated overhead costs. Other costs that are not consistently included are equipment (and leasing of equipment), regulatory filings, and miscellaneous direct costs. The Energy Commission staff uses the latter convention that includes these other costs.

Variable Operations and Maintenance Cost

Variable O&M is a function of the power plant operation and includes costs for:

- Scheduled outage maintenance including annual maintenance and overhauls
- Forced outage maintenance
- Water supply
- Environmental equipment maintenance

Scheduled outage maintenance is by far the largest expenditure.

Fuel Cost and Inflation Data

The fuel prices used in this report are summarized in **Table 17**. The natural gas average California prices are the final *2007 IEPR* price series. The high and low prices were derived as explained in Appendix D. KEMA developed the nuclear, coal, and biomass fuel prices. The deflator series is taken from Moody's Economy.com, dated November 11, 2008.

Table 17: Fuel Prices ($/MMBtu)

Year	Deflator Seiies 2009=1	Average CA	High CA	Low CA	Average Uranium	High Uranium	Low Uranium	Average Gassified Coal	High Gassified Coal	Low Gassified Coal	Average Biomass	High Biomass	Low Biomass
2009	1.000	6.56	9.13	4.74	0.63	0.74	0.53	1.80	3.13	1.31	2.00	3.00	1.75
2010	1.015	6.97	9.86	4.74	0.65	0.74	0.57	2.10	3.65	1.53	2.04	2.55	1.53
2011	1.031	7.29	10.45	4.75	0.68	0.78	0.59	2.15	3.74	1.57	2.08	2.60	1.56
2012	1.047	7.87	11.39	4.95	0.72	0.83	0.62	2.20	3.82	1.60	2.12	2.65	1.59
2013	1.064	8.28	12.10	5.06	0.75	0.87	0.64	2.24	3.90	1.64	2.16	2.70	1.62
2014	1.080	8.74	12.88	5.21	0.79	0.92	0.67	2.29	3.99	1.67	2.20	2.75	1.65
2015	1.097	9.01	13.36	5.26	0.82	0.94	0.69	2.34	4.07	1.71	2.24	2.80	1.68
2016	1.115	9.68	14.44	5.55	0.85	0.96	0.73	2.39	4.15	1.74	2.28	2.85	1.71
2017	1.133	10.20	15.32	5.76	0.88	0.99	0.76	2.43	4.23	1.78	2.33	2.91	1.74
2018	1.151	10.91	16.47	6.07	0.91	1.01	0.80	2.48	4.31	1.81	2.37	2.96	1.78
2019	1.170	11.78	17.86	6.46	0.94	1.04	0.84	2.52	4.39	1.84	2.41	3.02	1.81
2020	1.188	12.23	18.63	6.63	0.97	1.06	0.88	2.57	4.47	1.88	2.46	3.08	1.85
2021	1.207	12.66	19.37	6.79	1.00	1.10	0.89	2.61	4.55	1.91	2.51	3.13	1.88
2022	1.226	13.64	20.95	7.24	1.02	1.14	0.90	2.66	4.62	1.94	2.55	3.19	1.92
2023	1.245	14.16	21.82	7.44	1.05	1.17	0.91	2.70	4.70	1.97	2.60	3.25	1.95
2024	1.265	14.77	22.86	7.70	1.07	1.21	0.93	2.75	4.78	2.00	2.65	3.32	1.99
2025	1.284	14.73	22.86	7.61	1.10	1.25	0.94	2.79	4.85	2.04	2.70	3.38	2.03
2026	1.304	15.35	23.90	7.87	1.12	1.29	0.95	2.84	4.95	2.08	2.75	3.44	2.07
2027	1.324	15.75	24.60	8.01	1.15	1.33	0.96	2.90	5.04	2.11	2.81	3.51	2.11
2028	1.343	16.15	25.31	8.16	1.17	1.36	0.98	2.95	5.14	2.16	2.86	3.58	2.15
2029	1.363	16.80	26.39	8.43	1.20	1.40	0.99	3.01	5.23	2.20	2.91	3.64	2.19
2030	1.383	17.46	27.50	8.71	1.22	1.44	1.00	3.06	5.33	2.24	2.97	3.71	2.23
2031	1.404	18.08	28.58	8.94	1.25	1.49	1.02	3.12	5.42	2.27	3.03	3.78	2.27
2032	1.424	18.73	29.69	9.19	1.28	1.54	1.03	3.17	5.52	2.31	3.08	3.86	2.31
2033	1.445	19.33	30.75	9.41	1.31	1.58	1.05	3.23	5.62	2.36	3.14	3.93	2.36
2034	1.467	19.95	31.84	9.64	1.34	1.63	1.06	3.29	5.72	2.40	3.20	4.00	2.40
2035	1.488	20.57	32.93	9.86	1.37	1.68	1.07	3.35	5.82	2.44	3.26	4.08	2.45
2036	1.510	21.27	34.15	10.12	1.40	1.73	1.09	3.41	5.93	2.49	3.33	4.16	2.49
2037	1.532	21.98	35.39	10.38	1.43	1.78	1.10	3.47	6.04	2.53	3.39	4.24	2.54
2038	1.555	22.72	36.70	10.65	1.47	1.84	1.12	3.53	6.14	2.58	3.45	4.32	2.59
2039	1.578	23.50	38.08	10.94	1.50	1.89	1.13	3.60	6.26	2.62	3.52	4.40	2.64
2040	1.601	24.30	39.50	11.23	1.53	1.95	1.15	3.66	6.37	2.67	3.59	4.48	2.69
2041	1.624	25.12	40.95	11.52	1.57	2.01	1.17	3.73	6.48	2.72	3.65	4.57	2.74
2042	1.648	25.96	42.46	11.81	1.61	2.07	1.18	3.79	6.60	2.77	3.72	4.65	2.79
2043	1.673	26.82	44.00	12.11	1.64	2.13	1.20	3.86	6.72	2.82	3.79	4.74	2.85
2044	1.697	27.72	45.61	12.42	1.68	2.20	1.21	3.93	6.84	2.87	3.87	4.83	2.90
2045	1.722	28.65	47.28	12.74	1.72	2.26	1.23	4.00	6.96	2.92	3.94	4.92	2.95
2046	1.747	29.61	49.03	13.07	1.76	2.33	1.25	4.08	7.09	2.97	4.01	5.02	3.01

Source: Energy Commission

Financial Assumptions

Financial assumptions include capital structure, debt term, and economic/book life.

Table 18 summarizes the capital structure assumptions being used in the Model. Note that the debt to equity split is different for merchant gas-fired plants than other technology plants (renewables and alternative technologies). The rationale is that financial institutions are likely to see power purchase agreements signed under legislative and regulatory mandates, such as the Renewables Portfolio Standard (RPS), as less risky than those signed under open market conditions. The average case assumptions for IOU and merchant plants are taken from the Board of Equalization's *2008 Capitalization Rate Study*[7] and adjusted to match May 2009 financial market conditions. This source was chosen because it was developed by another state agency using a public review process. Debt costs for all three owner types were derived from public sources as of May 2009. Note that the equity rates of return are after-tax rates that are *grossed up* in the model to before-tax rates. The corresponding assumptions for the high- and low-cost cases for renewable plants are based on KEMA estimates. The appropriate discount rates and allowance for funds used during construction (AFUDC) rates are based on the weighted average cost of capital (WACC).

Table 18: Capital Cost Structure

	Average Case			
	% Equity	Equity Rate	Debt Rate	WACC
Merchant Fossil	60.0%	14.47%	7.49%	10.46%
Merchant Alternatives	40.0%	14.47%	7.49%	8.45%
Default IOU	52.0%	11.85%	5.40%	7.70%
Default POU	0.0%	0.0%	4.67%	4.67%
	High Case			
	% Equity	Equity Rate	Debt Rate	WACC
Merchant Fossil	80.0%	18.00%	10.00%	15.59%
Merchant Alternatives	60.0%	18.00%	10.00%	13.17%
Default IOU	55.0%	15.00%	9.00%	10.65%
Default POU	0.0%	0.0%	7.00%	7.00%
	Low Case			
	% Equity	Equity Rate	Debt Rate	WACC
Merchant Fossil	40.0%	14.47%	7.49%	8.45%
Merchant Alternatives	35.0%	14.00%	6.00%	7.21%
Default IOU	50.0%	10.00%	6.00%	6.78%
Default POU	0.0%	0.0%	4.00%	4.00%

Source: Energy Commission

[7] Board of Equalization, *Capitalization Rate Study*, March 2008, http://www.boe.ca.gov/proptaxes/pdf/2008capratestudy.pdf

General Assumptions

Insurance

Insurance is calculated differently depending on the type of developer. For an IOU, the cost is a fraction of the book value. For a merchant or POU plant, the cost is calculated as a fraction of the installed cost, and then escalated with nominal inflation. The fraction assumed for all three entities is 0.6 percent and is based on a California Public Utility Commission (CPUC) survey of brokers used in preparing the Market Price Referent[8].

Operation and Maintenance Escalation

Escalation of costs above general inflation for both fixed and variable O&M are estimated at 0.5 percent based on reviews of industry forecasts and the judgment of the analysts.

Book and Tax Life Assumptions

Book life represents the period over which shareholders expect to recover their initial investment. The debt term applies only to merchant developers as they are more likely to have project-specific financing.

Table 19 summarizes the debt term, book life, equipment life, and depreciation assumptions. They are shown for the average, high, and low cases used in the COG Modeling. The debt term assumptions are applicable to the merchant modeling only. They are not considered to be applicable to the IOU and POU modeling, which sets the debt life equal to the book life. This is done as debt is not project-specific for these developers; it is done on a companywide basis. The depreciation periods are used for the federal and state tax assumptions. The base federal tax life is taken from IRS Pub. 946 (2008), App. B, Asset class 49.[9] Accelerated depreciation allowances for certain technologies arise from the Energy Policy Acts dating back to 1992. These accelerated depreciation periods are a tax benefit that is captured in the COG Model and range of calculated levelized costs.

---

[8] California Public Utilities Commission, Energy Division, "Resolution E-4214," December 18, 2008.

[9] http://www.irs.gov/pub/irs-pdf/p946.pdf

Table 19: Life Term Assumptions

Technology	Debt Term (Years)			Book Life (Years)	Equipment (Years)	Depreciation (Years)	
	Average	High	Low			Federal	State
Small Simple Cycle	12	10	20	20	20	15	15
Conventional Simple Cycle	12	10	20	20	20	15	15
Advanced Simple Cycle	12	10	20	20	20	15	15
Conventional Combined Cycle (CC)	12	10	20	20	20	20	20
Conventional CC - Duct Fired	12	10	20	20	20	20	20
Advanced Combined Cycle	12	10	20	20	20	20	20
Coal - IGCC	15	10	20	20	40	15	20
Nuclear Westinghouse AP1000 (2018)	20	20	20	40	40	20	30
Biomass IGCC	15	10	20	20	20	5	20
Biomass Combustion - Fluidized Bed Boiler	12	10	20	20	20	5	20
Biomass Combustion - Stoker Boiler	12	10	20	20	20	5	20
Geothermal - Binary	20	20	20	30	30	5	20
Geothermal - Flash	20	20	20	30	30	5	20
Hydro - Small Scale & Developed Sites	20	20	20	30	30	5	30
Hydro - Capacity Upgrade of Existing Site	20	20	20	30	30	5	30
Ocean Wave (In-Service 2018)	20	20	20	30	30	5	30
Solar - Parabolic Trough	15	10	20	20	20	5	20
Solar - Photovoltaic (Single Axis)	15	10	20	20	20	5	20
Onshore Wind - Class 3/4	20	20	20	30	30	5	30
Onshore Wind - Class 5	20	20	20	30	30	5	30
Offshore Wind - Class 5 (In-Service 2018)	20	20	20	30	30	5	30

Source: Energy Commission

Federal and State Tax Rates

Corporate taxes are state and federal taxes as listed by the Franchise Tax Board and Internal Revenue Service. Again, these taxes depend on the developer type. A POU is exempt from state and federal taxes. The calculation of taxes for a merchant facility or IOU power plant is based on the taxable income. The rates are shown in **Table 20**.

Table 20: Federal and State Tax Rates

Tax	Rate
Federal Tax	35.0%
CA State Tax	8.84%
Total Tax Rate	40.7%

Source: Energy Commission

Ad Valorem

In California, ad valorem (property tax) differs depending on the developer:

- The merchant-owned facility tax is based on the market value assessed by the Board of Equalization, which is assumed to be equal initially to the installed cost of the facility. 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. The Model includes the assumption that an initial rate of 1.07 multiplied by the installed cost of the power plant and a property tax depreciation factor.
- The utility-owned plant tax is based on the value assessed by the Board of Equalization and is set to the net depreciated book value. The Model includes the assumption an initial cost of 1.07 multiplied by the book value. Counties are allocated property tax revenues based on the share of rate base within each county.
- Publicly owned plants are exempt from paying property taxes but may pay a negotiated in-lieu fee, which the Model assumes is equal to the calculated property tax.

Solar units are exempt from ad valorem. This is a tax benefit that is captured in the COG Model and is reflected in with and without tax benefit calculations in the report.

Sales Tax

California sales tax is estimated as 7.94 percent based on the 2007 Legislative Analyst's Office estimate. This does not include the temporary 1 percent surcharge because it is set to expire by the 2011-2012 fiscal year. Nevertheless, the sales tax does not show up directly in the analysis because the reported installed cost estimates are presumed to already include the sales tax, which is treated as a depreciable cost under federal tax law.

Tax Credits

Table 21 summarizes the technologies that are eligible for renewable energy production tax credits (REPTC) and renewable energy production incentives (REPI) for municipal utilities. The table summarizes those plants eligible for federal business energy or investment tax credits BETC/ITC under the 2005 and 2008 federal Energy Policy Acts (EPAct) and the 2009 American Recovery and Reinvestment Act (ARRA). The ARRA made most of the technologies that had been eligible for the REPTC also eligible for the ITC if the latter provided a larger benefit. The ARRA also allows those technologies claiming the ITC to be able to recover the entire benefit in a single year as a "grant" rather than capping the ITC that can be claimed at the amount of net taxable income in any single year. The REPI amount is adjusted for the proportion that is actually paid out from available federal funds, which is currently 19 percent of amounts eligible and requested for both Tier I and II. In addition, the table lists the amount of the state property tax exemption for solar technologies in the average case. For the high-cost cases, these tax credits and exemptions are allowed to expire after the legal deadline specified for each technology and program.

Table 21: Summary of Tax Credits

[redacted]

Notes:

1 - IGCC Production Credit is separate from REPTC, but similarly structured. Based on "refined coal" = $4.375/(13900 Btu/ton for anthracite / HR*(1+ParasiticLoad) for IGCC). Expiration date for ARRA ITC ambiguous.

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 percent in 2016

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

Source: Aspen

Comparison to *2007 IEPR* Assumptions

Table 22 compares key assumptions used for the *2009 IEPR* to those included in the *2007 IEPR*. The data for the first six technologies comes from Aspen Consulting, both for the *2007 IEPR* and for the *2009 IEPR*. The differences are due to having two more years of data and the change from just relying on survey data to also examining additional sources as described in Appendix C. The change in capacity factor comes from a reassessment of the performance of the California generating units since 2006. The increase in instant cost is documented back in **Table 10**. The changes in fixed and variable O&M are somewhat misleading as some of the variable costs were shifted to the fixed cost category to be more consistent with current practices of various other data collectors.

The rest of the technology data was provided in 2007 by NCI Consulting, as documented in the *2007 IEPR*. The 2009 data is provided by KEMA, Inc., and can be found in its supporting document *Renewable Energy Cost of Generation Update*. However, the two of the technologies that show the most change, ocean wave and solar photovoltaic, are not comparable in size.

Table 22: Comparison to *2007 IEPR*

Technology	Gross Capacity (MW)		Capacity Factor (%)		Instant Cost ($/kW)		Fixed O&M ($/kW-Year)		Variable O&M ($/MWh)	
In-Service Year = 2009 (2009$)	**2009 IEPR**	**2007 IEPR**	**2009 IEPR**	**2007 IEPR**	**2009 IEPR**	**2007 IEPR**	**2009 IEPR**	**2007 IEPR**	**2009 IEPR**	**2007 IEPR**
Small Simple Cycle	49.9	49.9	5%	5%	1292	1017	23.94	18.42	4.17	28.01
Conventional Simple Cycle	100	100	5%	5%	1231	966	17.40	11.43	4.17	27.59
Advanced Simple Cycle	200	200	10%	15%	827	794	16.33	7.41	3.67	27.26
Conventional Combined Cycle (CC)	500	500	75%	60%	1095	810	8.62	10.21	3.02	5.96
Conventional CC - Duct Fired	550	550	70%	60%	1080	834	8.30	9.88	3.02	4.53
Advanced Combined Cycle	800	800	75%	60%	990	800	7.17	8.73	2.69	4.04
Coal - IGCC	300	575	80%	60%	3184	2292	52.35	38.20	9.57	3.27
AP 1000 PWR Nuclear	960	1000	86%	85%	3950	3081	147.70	147.68	5.27	5.27
Biomass - IGCC	30	21.25	75%	85%	2997	3255	150.00	163.73	4.00	3.27
Biomass - Direct Combustion W/ Fluidized Bed	28	25	85%	85%	3254	3292	99.50	158.28	4.47	3.27
Biomass - Direct Combustion W/Stoker Boiler	38	25	85%	85%	2658	3023	160.10	141.90	6.98	3.27
Geothermal - Binary	15	50	90%	95%	4046	3226	47.44	76.41	4.55	3.79
Geothermal - Dual Flash	30	50	94%	93%	3718	2990	58.38	87.32	5.06	3.72
Hydro - Small Scale	15	181	30%	52%	1730	4301	17.57	14.19	3.48	3.00
Ocean - Wave (2018)	40	1	26%	15%	2587	7511	36.00	32.75	12.00	25.49
Solar - Parabolic Trough	250	63.5	27%	27%	3687	4194	68.00	65.49	0.00	0.00
Solar - Photovoltaic (Single Axis)	25	1	27%	22%	4550	10023	68.00	26.20	5.50	0.00
Wind - Class 5	100	50	42%	34%	1990	2043	13.70	32.75	0.00	0.00

Source: Energy Commission

Glossary

Acronym	Definition
$/kW	$ Per kilowatt-hour
$/MMBtu	$/Million Btu
$/MWh	$ per megawatt-hour
¢/kWh	Cents per kilowatt-hour
ACC	Air-cooled condenser
ACOE	Army Corps of Engineers
AFC	Application for Certification
AFUDC	Allowance for funds used during construction
BETC/ITC	Business energy or investment tax credits
Btu	British thermal unit
Btu/kWh	British thermal unit per kilowatt-hour
CC	Combined cycle
CCS	Carbon capture and sequestration
CERA	Cambridge Energy Research Associates
CF	Capacity factor
coal-IGCC	Coal-integrated gasification combined cycle
CPUC	California Public Utilities Commission
CRS	Congressional Research Service
CT	Combustion turbine
DG	Distributed generation
DSM	Demand-side management
EAO	Energy Annual Outlook
EFOR	Equivalent FOR
EIA	Energy Information Administration
Energy Commission	California Energy Commission
EPAct	Energy Policy Act

Acronym	Definition
FOR	Forced outage rate
GADS	Generating Availability Data System
GW/GWh	Gigawatt/Gigawatt-hour
HHV	Higher heating value
HRSG	Heat recovery steam generator
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
kW	Kilowatt
LCR	Local capacity requirements
MID	Modesto Irrigation District
Model	Cost of Generation Model
MOR	Maintenance outage rate
MW/MWh	Megawatt/megawatt-hour
NERC	North American Reliability Council
NWPCC	Northwest Power and Conservation Council
O&M	Operating and maintenance
ODCs	Other direct costs
PIER	Public Interest Energy Research
PMT	Payment (used as annual levelized cost)
POU	Publicly owned utility
PPAs	Power purchase agreements
PPI	Producers Price Index
PV	Present value
QFER	Quarterly Fuels and Energy Report
REPI	Renewable energy production incentives
REPTC	Renewable energy production tax credits
REZ	Resource energy zone
RPS	Renewables Portfolio Standard

Acronym	Definition
SC	Simple cycle
SCR	Selective catalytic reduction
SOF	Schedule outage factor
SOH	Scheduled outage hours
WACC	Weighted average cost of capital
WEP	Wholesale electricity prices
WSAC	Wet surface air condenser

APPENDIX A: Cost of Generation Model

This appendix describes the Cost of Generation Model (Model), including its inputs and outputs. This appendix also describes ancillary features that the model provides:

- The screening curve function
- The sensitivity curve function
- The wholesale electricity price forecast function

Model Overview

A simplified flow chart of the Model's inputs and outputs is shown in **Figure A-1**.

Using the inputs on the left side of the flow chart, which are described in detail later in this chapter, the Model can produce the outputs shown on the right side of the flow chart. The top set of output boxes show the levelized costs:

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

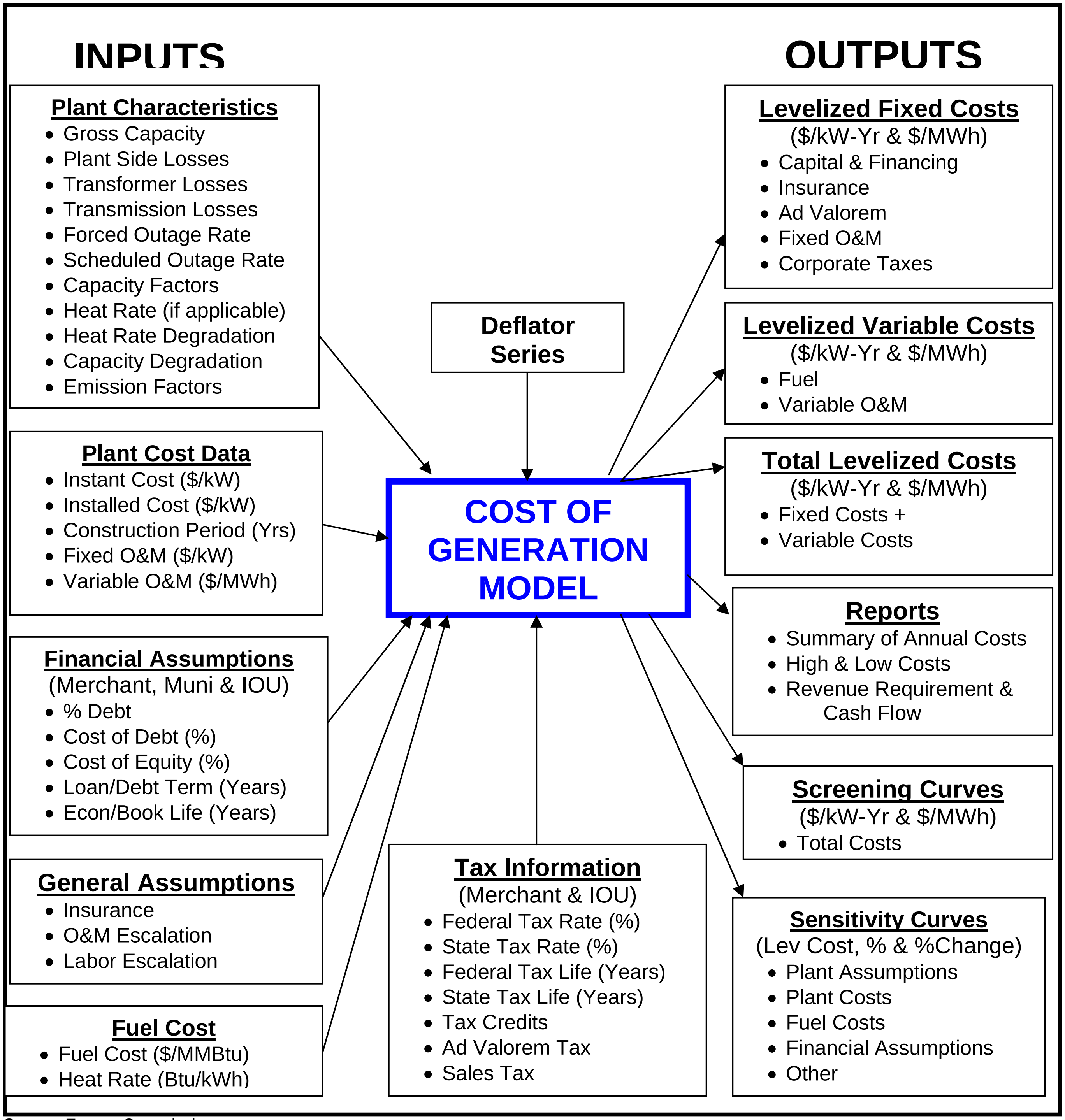
These are typical results from most cost of generation models. These results are used in almost any study that involves the cost of generation technologies. They can be used to evaluate the cost of a generation technology as a part of a feasibility study or to compare the differences between generation technologies. They also can be used for system generation or transmission studies.

This Model is more useful than the typical model since it also provides high and low levelized costs. It is also more unique than the traditional model since it can create three other outputs that are useful, but not commonly provided in the models:

- Annual costs, which are not traditionally displayed in both a table and a graph.
- Screening curves, which show the relationship between levelized cost and capacity factor—an addition that makes the Model much more useful in evaluating cost of generation costs and comparing different technologies.
- Sensitivity curves, which show the percentage change in outputs (levelized cost) as various input variables are changed.

In addition, the Model can also be used to forecast the cost of wholesale electricity, which is explained later in the chapter.

Figure A-1: Cost of Generation Model Inputs and Outputs



Source: Energy Commission

Model Structure

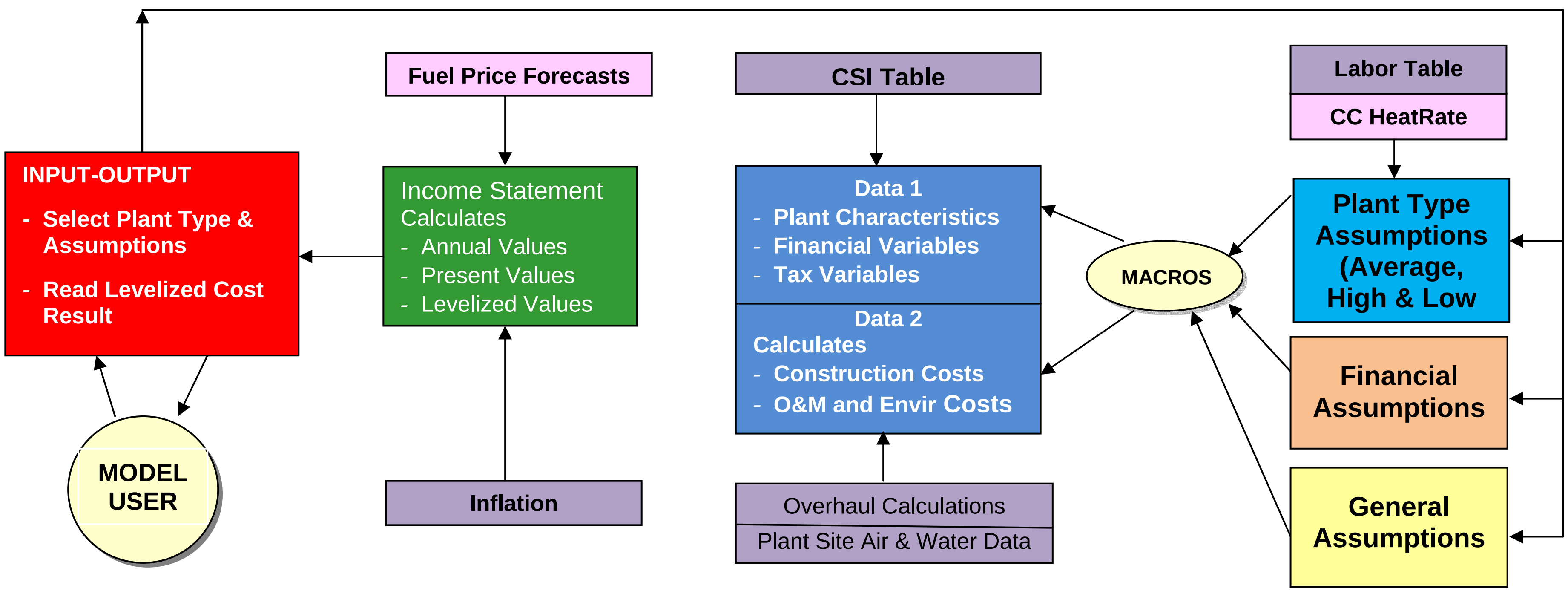
The Model is a spreadsheet model that calculates levelized costs for 21 technologies. These include nuclear, combined cycle, integrated gasification combined cycle, simple cycle, and various renewable technologies. The Model is designed to accommodate additional technologies and includes a function for storing the results of scenario runs for these technologies. The Model is contained within a single Excel file or workbook using Microsoft terminology. This workbook consists of 20 spreadsheets or worksheets, but 2 of these are informational and do not contribute to the calculations.

The relationship of these worksheets is illustrated in **Figure A-2**.

Changes	Tracks Model modifications using version numbers.
Instructions	General Instructions & Model Description.
WEP Forecast	Estimates Wholesale Electric Price Forecast
Adders	Provides Adder Costs that can be entered exogenously for the combined cycle & simple cycle units.
Input-Output	User selects Assumptions - Levelized Costs are reported along with some key data values.
Data 1	Plant, Financial, & Tax Data are summarized - User can override data for unique scenarios.
Data 2	Construction, O&M Costs are calculated in base year dollars.
Income Statement	Calculates Annual Costs and Levelizes those Costs – Using Revenue Requirement accounting
Income Cash -Flow	Calculates Annual Costs and Levelizes those Costs – Using Cash-Flow accounting
Plant Type Assumptions	Summary of Data Assumptions summary for each Plant Type.
PTA - Average	Average Plant Type Assumptions
PTA - High	High Plant Type Assumptions
PTA - Low	Low Plant Type Assumptions
Financial Assumptions	Data Assumptions summary of all Financial Data.
Tax Incentives	Summary of Tax Incentives
General Assumptions	General Assumptions summary such as Inflation Rates & Tax Rates.
Plant Site Air & Water Data	Regional Air Emissions & Water Costs - Used by Data 2 Worksheet.
Overhaul Calcs	Calculates Overhaul & Equipment Replacement Costs - Used by Data 2 Worksheet.
Inflation	Calculates Historical & Forward Inflation Rates based on GDP Price Deflator Series - Used by Income Statement Worksheet.
Fuel Price Forecasts	Fuel Price Forecast - Used by the Income Statement Worksheet.
Heat Rate Table	Shows the regression and provides the Heat Rate factors.
Labor Table	Calculates the Labor Cost components.

Source: Energy Commission

Figure A-2: Block Diagram for Cost of Generation Model



Source: Energy Commission

One way to better understand the Model is to visualize the “Income Revenue” and “Income Cash-Flow” worksheets as a model, the “Input-Output” worksheet as the control module, which also summarizes the results, and the remaining worksheets as data inputs. Data 1 and 2 could be considered the data set (broken into two parts) that is derived from the Plant Type Assumptions worksheets and the remaining worksheets (auxiliary data).

Input-Output Worksheet

This is where the user selects the generation technology and characteristics and reads the final result. **Figure A-3** shows the Input Selection box, Through the use of drop-down windows, the user selects the power plant type, the financial assumptions, the general assumptions, fuel type, and regional location of the power plant. The user enters the start year.

Figure A-3: Technology Assumptions Selection Box

Source: Energy Commission

The remaining options are more complex and require further description. The study perspective sets the location of the calculation: plant side of the transformer, transmission side of the transformer, or the delivery point. All data reported in this Model are based on the point of power delivery, that is, the electricity user. The reported construction cost basis allows the user to enter the data as instant or installed. The turbine configuration allows for non-standard configurations for the combined cycle units. The standard configuration is two combustion turbine units and one steam generator—thus the number "2." The next entry is carbon price—but these prices have not yet been established by the Energy Commission and are therefore not used in *IEPR*. The Cost Scenario allows the user to select an average, high, or low set of assumptions. The Tax Loss Treatment allows the user to have the model carry tax losses forward or to take them all in the current year.

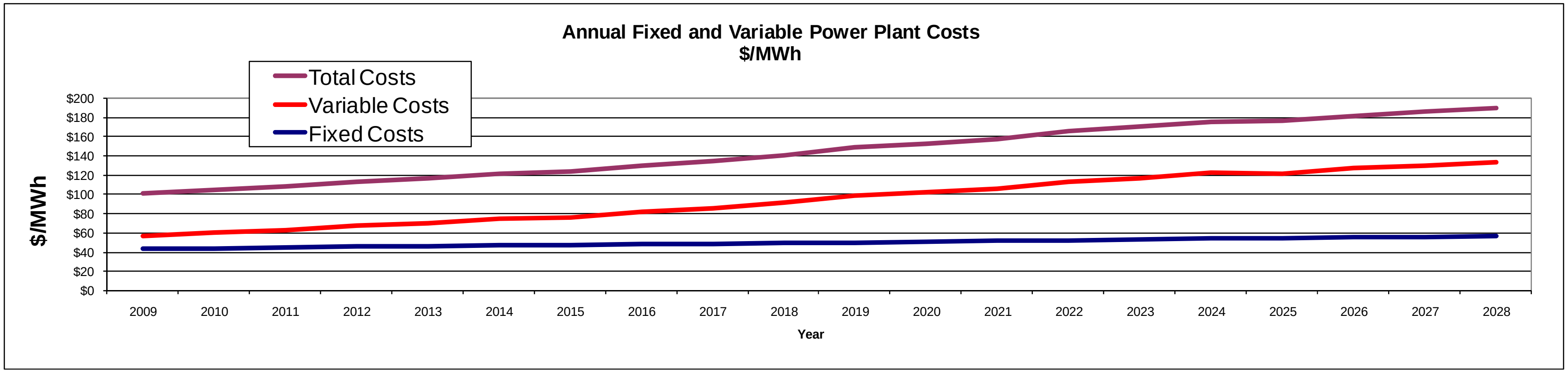
The Model collects the relevant data as directed by the selection box and delivers it to the data worksheets. The income statement then uses the data worksheets to calculate the levelized costs and reports those costs back to the input-output worksheet to the table shown in **Figure A-4**. This version for the first time reports transmission service costs.

Figure A-4: Levelized Cost Output

Source: Energy Commission

Figure A-5 shows the annual costs as a table and a graph. This is useful as information and in identifying model problems.

Figure A-5: Annual Costs—Merchant Combined Cycle Plant



[redacted]

Source: Energy Commission

Assumptions Worksheets

Most of the data used in the Model are compiled into these three worksheets. These worksheets store the data for the multitude of technologies and data assumptions that give the Model its flexibility

Plant Type Assumptions—This worksheet stores the power plant characteristics and cost data, such as plant size, capacity factor, outage rates, heat rates, degradation factors, construction periods, instant costs, operation and maintenance costs, environmental costs, and water usage costs.

Financial Assumptions—This worksheet stores the capital structure and cost of capital data for the three main categories of ownership: merchant, IOU, and publicly owned. 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.

General Assumptions—These are a multitude of assumptions that are common to all power plant types, such as inflation rates, tax rates, tax credits, as well as transmission losses and ancillary service rates.

Based on the user selections in the input-output worksheet, the relevant data in these assumptions worksheets are gathered by a macro and sent to the data worksheets. These values are color-coded within the worksheets as follows:

Indicates area for data modification
Plant Type Assumptions
Financial Assumptions
General Assumptions

Source: Energy Commission

Data Worksheets

This is where the macro stores the data selected from the above-described assumptions worksheets. It also performs some basic calculations to prepare data for the income statement worksheet. Data 1 and Data 2 worksheets can be envisioned as two parts of the main dataset to be used in the income statement. These are separated solely to keep the worksheets to a reasonable size. Data 1 and 2 also provide the opportunity for the user to modify or replace the data that came from the assumptions worksheets. Care should be taken to modify only those areas that are shaded in color.

Data 1—This worksheet summarizes key data: plant capacity size and energy data, fuel use (such as heat rate and generation), operational performance data (such as forced outage rate and scheduled outage factor), key financial data (such as inflation rates and capital structure), and tax information (such as tax rates and tax benefits). It also does some calculations to compute certain necessary variables.

Heat Rate Table—This worksheet shows the regression that created the heat rate formula as a function of capacity factor in the Data 1 worksheet.

Data 2—This worksheet calculates Instant Cost, Installed Cost, Fixed O&M, and Variable O&M. These calculations depend on data from the following worksheets:

Plant Site Air and Water Data—These are emission and water costs on regional basis that are located outside the Data 2 worksheet.

Overhaul Calculations—These costs are calculated outside the Data 2 worksheet since they are non-periodic overhaul costs that require special treatment to derive the necessary base-year costs needed by the Data 2 worksheet.

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.

Labor Table—This worksheet calculates the labor costs that are used in the fixed O&M cost calculations in the Data 2 worksheet.

Fuel Price Forecasts—This worksheet provides the fuel prices ($/MMBtu) to the income statement worksheet. For the natural gas price forecast, it provides prices by utility service area, as well as a California average value. It allows storage of different forecasts if needed to study various scenarios. These forecasts should be updated regularly to represent the most recent Energy Commission forecasts. The inflation factors used in this worksheet come from and must absolutely be consistent with the inflation worksheet.

Inflation—This worksheet provides inflation factors used by the income statement worksheet, 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 Worksheet

The Model has two Income Statement worksheets: revenue requirement for IOU and POU power plants and cash-flow for merchant plants. In each case, the Income Statement takes the data from the above data sources and calculates the fixed and variable cost components of total levelized cost. It develops the yearly costs, the present values of those costs, and finally the levelized costs.

Model Limitations

Models are inherently limited because a number of assumptions must be made for each generation technology. This section discusses these limitations and what this model has done to overcome these limitations. However, a cost of generation model is essentially a screening model. These models assume an average set of assumptions, which may not be applicable to the plant being assessed. Also, these cost estimates tell nothing about how the power plant will affect the system. Better answers to both of these questions can be found by using a production cost or market model. Finally, all of this ignores environmental, risk, and diversity factors, which may in the final analysis be the determining factors.

The key assumptions in modeling that can lead to errors are:

- Capital costs
- Fuel costs
- Capacity factors
- Heat rates for thermal plants

Capital Costs

Deriving capital costs is challenging, particularly for alternative technologies since costs tend to drop with increased development over time. Even for well-developed technologies, such as combined cycle and simple cycle plants, it is difficult because of varying location and situational costs. Developers generally keep this information confidential to maintain a competitive edge over other developers. The Energy Commission surveyed actual costs for simple cycle and combined cycle units during the *2007 IEPR,* agreeing to keep specific data confidential. Although this was done very systematically and proved to be highly accurate, an updated assessment for this *2009 IEPR* finds that these costs have changed so dramatically that staff's present estimates for simple cycle units are 35 percent higher and for combined cycle units 50 percent higher.

Fuel Costs

Fuel cost is highly unpredictable and difficult to forecast with a high degree of accuracy. Appendix D illustrates just how difficult it is to accurately forecast fuel cost data, showing estimating errors up to several hundred percent.

Capacity Factors

Models are inherently limited because the user must assume a specific capacity factor, which may or may not be applicable to the power plant under consideration. This is a common problem for combined cycle and simple cycle power plants. Combined cycle units are all too commonly modeled as having capacity factors in the vicinity of 90 percent, but the historical information on California power plants, as summarized in **Table A-1**, shows that the average is closer to 60 percent or less. The Model attempts to deal with this problem using the screening curve function, as described below.

Table A-1: Actual Historical Capacity Factors

Power Plant	QFER 2004	QFER 2005
Moss Landing Power Plant	55.5%	52.6%
Los Medanos	74.3%	74.7%
Sunrise Power	62.1%	65.7%
Elk Hills Power, LLC	79.9%	72.4%
High Desert Power Project	51.9%	50.3%
Sutter	72.0%	51.3%
Delta Energy Center	72.6%	69.5%
Blythe Energy LLC	26.8%	19.6%
La Paloma Generating	57.2%	46.4%
Von Raesfeld	nd	31.6%
Woodland	nd	51.5%
Average	61.3%	53.2%

Source: Energy Commission

Heat Rates

An actual thermal power plant being considered, such as a combined cycle unit, may operate at an entirely different capacity factor than that selected for the Model. In fact, these plants typically operate at different capacity factors from month to month and even day to day. These varying capacity factors result in differing heat rates. A combined cycle unit has the most efficient (lowest) heat rate at full power. Operation at lower power levels produces less efficient operation (higher heat rates). Two identical power plants with the same capacity factor can have widely different average annual heat rates. For example, both could have 50 percent capacity factors if one operated at full power for half of the year and the other operated at half power for the entire year. Obviously, the latter unit would have a much higher heat rate.

Energy Commission Features to Overcome Modeling Limitations

Recognizing the many factors that compromise a cost of generation estimate, the Energy Commission has implemented a number of features in its data collection and modeling.

Data Collection

Beginning with *2007 IEPR*, the Energy Commission implemented a data collection process that gathered actual as-built data from the California power plant developers. This year the process concentrated on comparing staff's data against other reliable sources as a benchmark. The Commission will continue to gather this data using the most knowledgeable engineers and reevaluating estimates in light of changing prices and nominal escalation.

High and Low Forecasts

The Energy Commission has modified its data gathering and model to provide high and low estimates trying to capture the most reasonably high- and low-cost parameters available.

Completeness of Assumptions

There is a tendency to oversimplify the modeling by ignoring cost factors such as plant-side losses, which can have a large impact. The Energy Commission's Cost of Generation Model captures all assumptions, including plant-side losses, transformer losses, construction periods, transmission losses, capacity degradation, heat-rate degradation, environmental compliance costs, and transmission costs

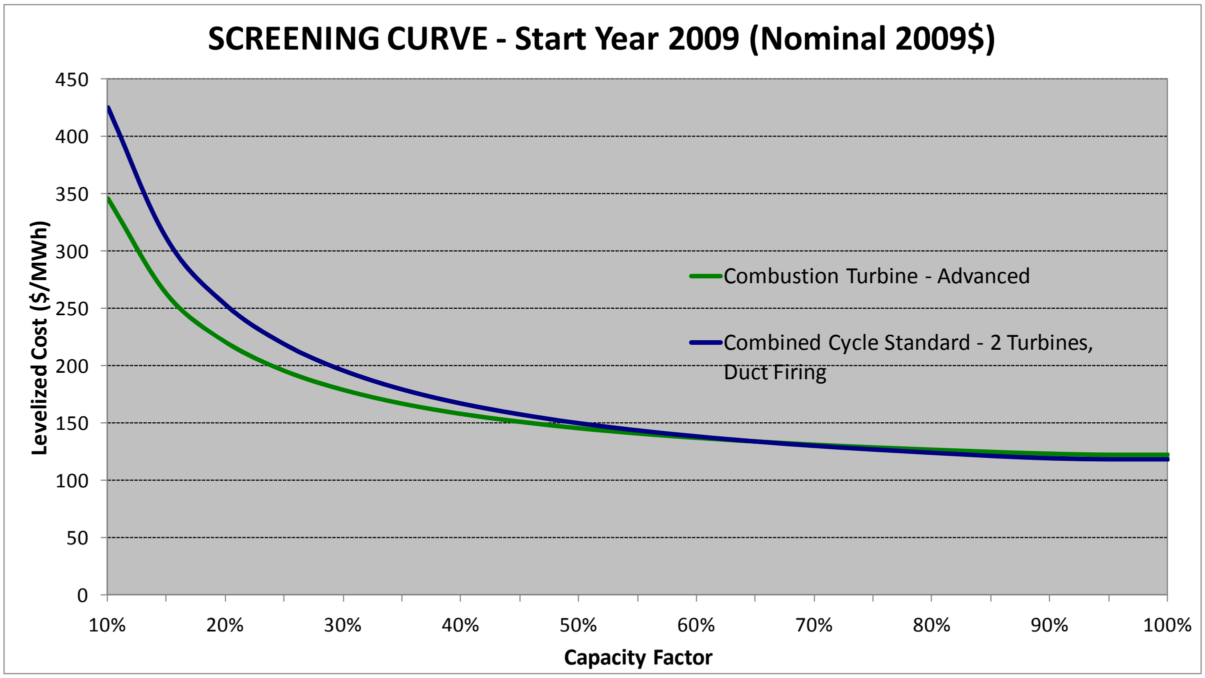
Model's Screening Curve Function

Screening curves allow one to estimate the levelized cost for various capacity factors, rather than the singular capacity factor that is typical of models. This is useful in many ways. The most obvious is that it allows the user to estimate levelized costs for its specific assumption of capacity factor. It also allows the user to assess the cost risk of incorrectly estimating the capacity factor. It allows for the comparison of various technologies as a function of capacity factor – that is, at what capacity factor one technology becomes less costly than another.

The Energy Commission's Cost of Generation Model is somewhat unique in that it recognizes the reality that heat rate is a function of capacity factor and corrects for this in the screening curve. By analyzing historical data from operating power plants in California (Energy Commission's QFER database), it was possible to find a relationship between capacity factor and heat rate that has a high statistical level of confidence—and that formula (through regression) has been embedded in the Model.

The levelized cost can be shown as $/MWh or $/kW-Year**. Figure A-6** illustrates a $/MWh screening curve. **Figure A-7** shows the corresponding interface window.

Figure A-6: Screening Curve in Terms of Dollars per Megawatt Hour



Source: Energy Commission

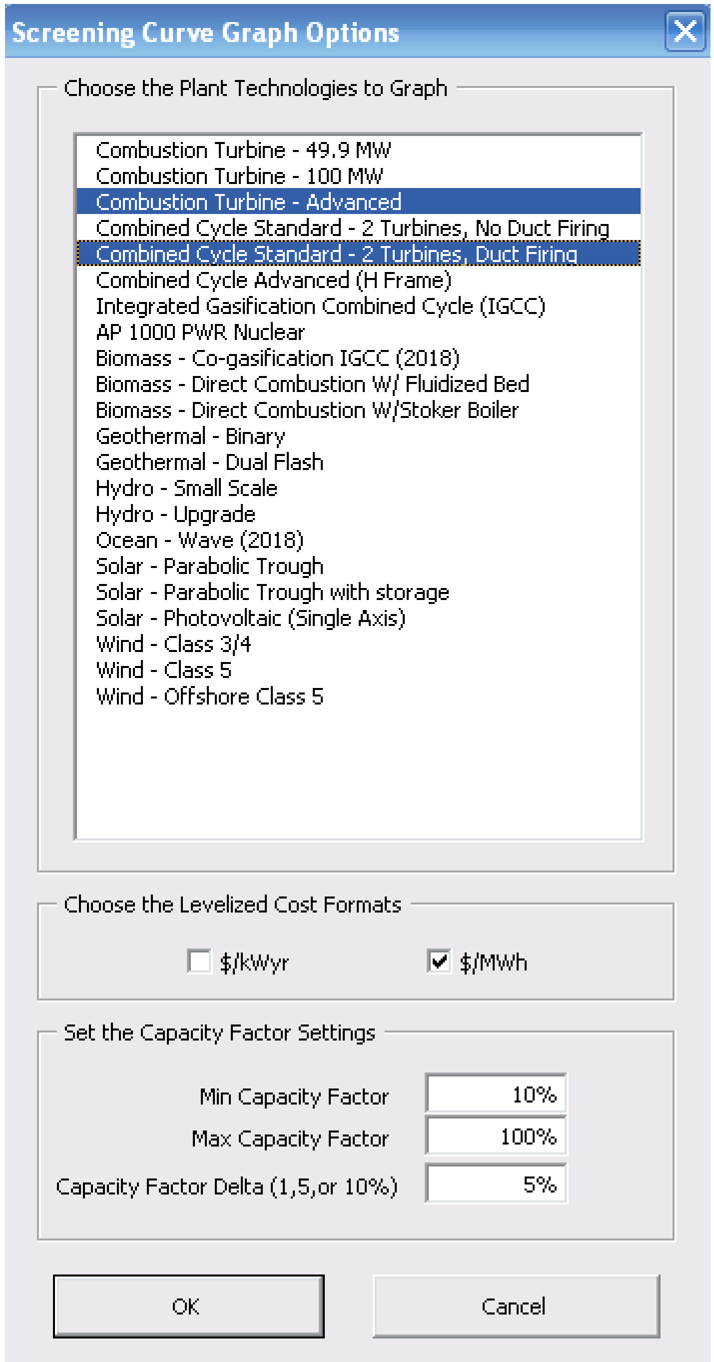
Model's Sensitivity Curve Function

Although the screening curves can prove useful, they address only one variable to the base case assumptions when estimating levelized costs—the capacity factor. Staff's new sensitivity curves address a multitude of assumptions: capacity factor, fuel prices, installed cost, discount rate (WACC), percentage equity, cost of equity, cost of debt, and any other variable that should be considered. 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).

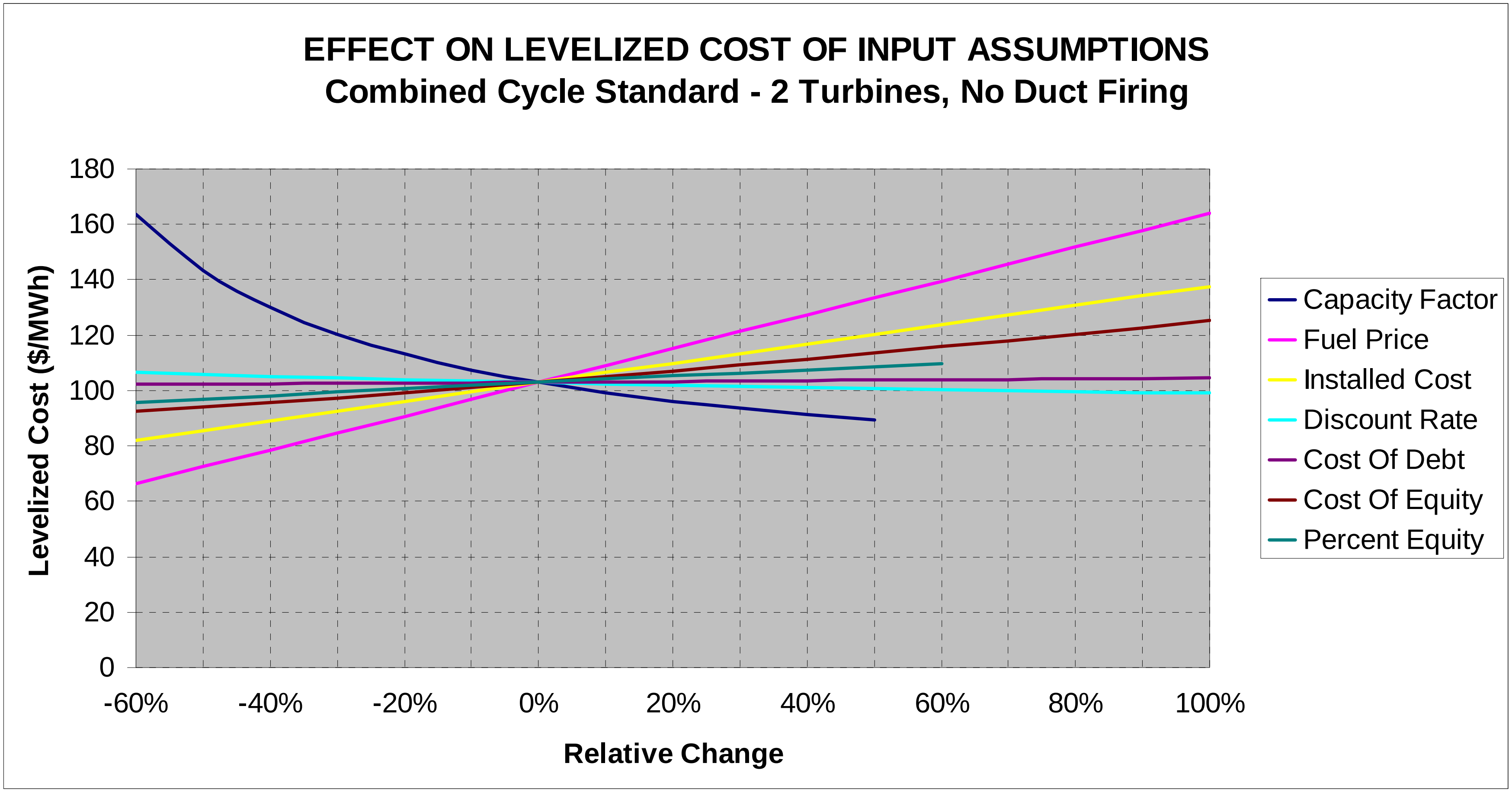
Figure A-8 shows a sensitivity curve. **Figure A-9** shows the interface window for the above sensitivity curve.

Figure A-7: Interface Window for Screening Curve



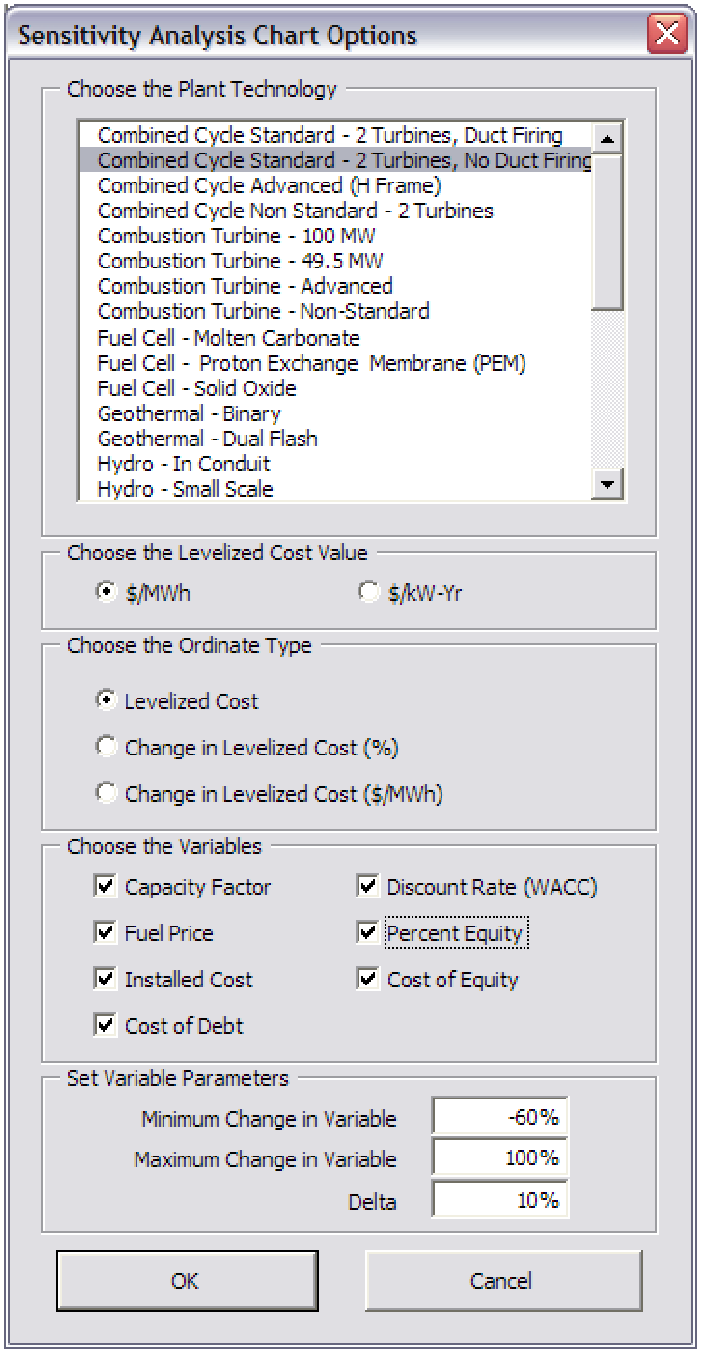
Source: Energy Commission

Figure A-8: Sample Sensitivity Curve



Source: Energy Commission

Figure A-9: Interface Window for Screening Curves



Source: Energy Commission

Model's Wholesale Electricity Price Forecast Function

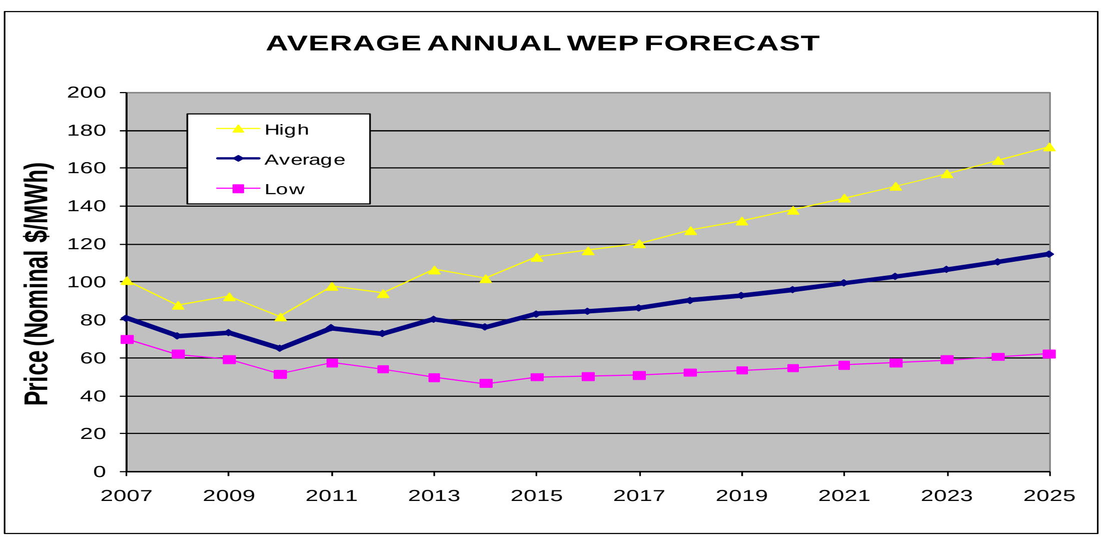
The Model can be used along with the Marketsym model—or some other production cost model—to forecast wholesale electricity prices. The Model can calculate the fixed-cost portion of the wholesale electricity prices (WEP), but not the variable portion. The Marketsym model, on the other hand, can calculate the variable portion of the WEP, but not the fixed portion.

The details of this process are complicated and outside the scope of this report but can be briefly explained as follows. To estimate the fixed portion, the Model must be run to emulate the fixed cost for each of the combined cycles on-line during the period from 2001 to the end of the forecast period. These annual costs are then analyzed to find the following for each year of the forecast period: the most expensive unit in each year, the least expensive unit in each year, and the average cost of all the generating units.

The Marketsym model is run in the cost-based mode to produce market clearing prices for all the years of the forecast using all the above-identified resource additions. The Marketsym model is then run for a high and low gas price.

The fixed costs from the Model are then added to the variable costs from the Marketsym model to get the WEP forecast. **Figure A-10** illustrates the resulting wholesale electricity price forecast. The maximum wholesale electricity price is the most expensive generating unit in each year. The minimum wholesale electricity price is the least expensive generating unit in each year. The average wholesale electricity price is the average of all the generating units operating in that year.

Figure A-10: Illustrative Example for Wholesale Electricity Price Forecast



Source: Energy Commission

APPENDIX B: Component Levelized Costs

Chapter 1 summarized levelized component costs only in $/MWh for merchant plants only. This appendix provides within **Table B-1** through **Table B-6** a comprehensive summary in $/MWh and $/kW-Year, for merchant, IOU and POU plants for the average case.

Table B-1: Component Costs for Merchant Plants (Nominal $/MWh)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/MWh (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	482.17	23.44	31.87	66.81	134.18	**738.46**	95.54	5.08	**100.62**	5.24	**844.31**
Conventional Simple Cycle	100	459.43	22.33	30.36	48.56	128.14	**688.82**	95.54	5.08	**100.62**	5.24	**794.67**
Advanced Simple Cycle	200	158.70	7.71	10.49	22.79	44.28	**243.98**	88.15	4.47	**92.62**	5.24	**341.84**
Conventional Combined Cycle (CC)	500	28.64	1.38	1.88	1.61	9.42	**42.93**	72.05	3.66	**75.71**	5.21	**123.84**
Conventional CC - Duct Fired	550	30.26	1.46	1.99	1.67	9.95	**45.32**	73.19	3.66	**76.85**	5.21	**127.38**
Advanced Combined Cycle	800	25.91	1.25	1.70	1.34	8.52	**38.73**	67.17	3.26	**70.43**	5.21	**114.36**
Coal - IGCC	300	72.98	3.83	5.21	9.38	-11.33	**80.08**	19.38	11.98	**31.36**	5.38	**116.83**
Biomass IGCC	30	59.97	3.84	5.08	29.12	-26.40	**71.62**	26.75	5.08	**31.84**	6.54	**109.99**
Biomass Combustion - Fluidized Bed Boiler	28	60.92	3.78	5.00	17.56	-23.00	**64.26**	27.35	5.83	**33.18**	6.58	**104.02**
Biomass Combustion - Stoker Boiler	38	48.64	3.02	4.00	27.66	-18.49	**64.83**	28.06	8.91	**36.97**	6.45	**108.25**
Geothermal - Binary	15	84.76	6.52	9.85	11.15	-48.94	**63.33**	0.00	5.94	**5.94**	13.83	**83.11**
Geothermal - Flash	30	74.41	5.74	8.67	13.19	-43.22	**58.79**	0.00	6.61	**6.61**	13.51	**78.91**
Hydro - Small Scale & Developed Sites	15	93.65	7.03	10.62	11.10	-46.78	**75.62**	0.00	4.85	**4.85**	6.00	**86.47**
Hydro - Capacity Upgrade of Existing Site	80	43.98	2.97	4.48	7.53	-0.84	**58.12**	0.00	3.16	**3.16**	5.68	**66.96**
Solar - Parabolic Trough	250	257.53	16.58	0.00	47.03	-114.69	**206.45**	0.00	0.00	**0.00**	18.26	**224.70**
Solar - Photovoltaic (Single Axis)	25	317.91	20.47	0.00	47.03	-141.44	**243.96**	0.00	0.00	**0.00**	18.26	**262.21**
Onshore Wind - Class 3/4	50	74.66	5.53	8.36	5.90	-36.18	**58.28**	0.00	6.97	**6.97**	7.16	**72.41**
Onshore Wind - Class 5	100	65.77	4.87	7.37	5.20	-31.88	**51.34**	0.00	6.97	**6.97**	7.16	**65.47**

Source: Energy Commission

Table B-2: Component Costs for IOU Plants (Nominal $/MWh)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/MWh (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	371.37	13.49	24.69	67.87	68.39	**545.81**	99.40	5.16	**104.56**	5.32	**655.69**
Conventional Simple Cycle	100	353.82	12.85	23.52	49.33	65.43	**504.96**	99.40	5.16	**104.56**	5.32	**614.84**
Advanced Simple Cycle	200	121.36	4.41	8.07	23.15	22.47	**179.45**	91.72	4.54	**96.26**	5.32	**281.03**
Conventional Combined Cycle (CC)	500	21.74	0.79	1.44	1.64	5.08	**30.69**	75.07	3.71	**78.78**	5.29	**114.76**
Conventional CC - Duct Fired	550	22.97	0.83	1.53	1.69	5.36	**32.38**	76.26	3.71	**79.97**	5.29	**117.64**
Advanced Combined Cycle	800	19.67	0.71	1.31	1.37	4.59	**27.65**	69.99	3.31	**73.29**	5.29	**106.23**
Coal - IGCC	300	60.21	2.19	4.00	9.53	-14.96	**60.98**	19.72	12.17	**31.88**	5.47	**98.32**
Biomass IGCC	30	60.65	2.20	4.03	29.25	-23.03	**73.10**	26.87	5.10	**31.98**	6.57	**111.65**
Biomass Combustion - Fluidized Bed Boiler	28	59.67	2.17	3.97	17.64	-22.63	**60.82**	27.47	5.85	**33.33**	6.61	**100.75**
Biomass Combustion - Stoker Boiler	38	47.72	1.73	3.17	27.79	-18.15	**62.26**	28.18	8.95	**37.13**	6.47	**105.87**
Geothermal - Binary	15	91.92	3.94	7.21	11.38	-40.94	**73.51**	0.00	5.98	**5.98**	14.03	**93.52**
Geothermal - Flash	30	80.93	3.47	6.35	13.47	-36.06	**68.16**	0.00	6.65	**6.65**	13.70	**88.51**
Hydro - Small Scale & Developed Sites	15	99.04	4.24	7.76	11.26	-37.69	**84.61**	0.00	4.89	**4.89**	6.04	**95.54**
Hydro - Capacity Upgrade of Existing Site	80	41.81	1.79	3.28	7.65	1.95	**56.48**	0.00	3.18	**3.18**	5.72	**65.39**
Solar - Parabolic Trough	250	262.48	9.54	0.00	47.28	-99.37	**219.93**	0.00	0.00	**0.00**	18.35	**238.27**
Solar - Photovoltaic (Single Axis)	25	323.91	11.77	0.00	47.28	-122.59	**260.37**	0.00	0.00	**0.00**	18.35	**278.71**
Onshore Wind - Class 3/4	50	77.68	3.33	6.09	5.97	-29.56	**63.51**	0.00	7.02	**7.02**	7.22	**77.75**
Onshore Wind - Class 5	100	68.44	2.93	5.37	5.26	-26.05	**55.94**	0.00	7.02	**7.02**	7.22	**70.19**

Source: Energy Commission

Table B-3: Component Costs for POU Plants (Nominal $/MWh)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/MWh (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	135.36	11.84	11.43	34.58	0.00	**193.21**	104.12	5.25	**109.38**	5.42	**308.01**
Conventional Simple Cycle	100	128.99	11.28	10.89	25.14	0.00	**176.30**	104.12	5.25	**109.38**	5.42	**291.10**
Advanced Simple Cycle	200	58.41	5.11	4.93	15.73	0.00	**84.17**	96.08	4.62	**100.70**	5.42	**190.29**
Conventional Combined Cycle (CC)	500	15.62	1.37	1.32	1.68	0.00	**19.98**	78.77	3.78	**82.55**	5.38	**107.91**
Conventional CC - Duct Fired	550	16.50	1.44	1.39	1.73	0.00	**21.07**	80.02	3.78	**83.80**	5.38	**110.25**
Advanced Combined Cycle	800	14.13	1.24	1.19	1.39	0.00	**17.96**	73.43	3.37	**76.80**	5.38	**100.14**
Coal - IGCC	300	43.26	3.78	3.65	9.71	0.00	**60.41**	20.11	12.39	**32.51**	5.57	**98.49**
Biomass IGCC	30	43.59	3.81	3.68	29.81	-2.58	**78.31**	27.38	5.20	**32.58**	6.69	**117.58**
Biomass Combustion - Fluidized Bed Boiler	28	42.96	3.76	3.63	17.98	-2.58	**65.74**	27.98	5.96	**33.94**	6.74	**106.42**
Biomass Combustion - Stoker Boiler	38	34.35	3.00	2.90	28.33	-2.58	**66.00**	28.70	9.12	**37.82**	6.60	**110.42**
Geothermal - Binary	15	61.21	7.01	6.73	12.75	-2.18	**85.52**	0.00	6.20	**6.20**	15.19	**106.91**
Geothermal - Flash	30	53.86	6.17	5.93	15.08	-2.18	**78.86**	0.00	6.90	**6.90**	14.83	**100.59**
Hydro - Small Scale & Developed Sites	15	65.29	7.48	7.18	12.19	0.00	**92.14**	0.00	5.08	**5.08**	6.28	**103.50**
Hydro - Capacity Upgrade of Existing Site	80	27.56	3.16	3.03	8.28	0.00	**42.03**	0.00	3.31	**3.31**	5.95	**51.29**
Solar - Parabolic Trough	250	190.47	16.66	0.00	48.38	-2.72	**252.78**	0.00	0.00	**0.00**	18.74	**271.52**
Solar - Photovoltaic (Single Axis)	25	235.05	20.55	0.00	48.38	-2.72	**301.26**	0.00	0.00	**0.00**	18.74	**320.00**
Onshore Wind - Class 3/4	50	50.21	5.75	5.52	6.35	-2.18	**65.66**	0.00	7.31	**7.31**	7.55	**80.52**
Onshore Wind - Class 5	100	44.24	5.07	4.87	5.59	-2.18	**57.58**	0.00	7.31	**7.31**	7.55	**72.44**

Source: Energy Commission

Table B-4: Component Costs for Merchant Plants (Nominal $/kW-Year)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/kW-Yr (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	198.11	9.63	13.09	27.45	55.13	**303.42**	39.25	2.09	**41.34**	2.15	**346.91**
Conventional Simple Cycle	100	188.77	9.17	12.48	19.95	52.65	**283.02**	39.25	2.09	**41.34**	2.15	**326.51**
Advanced Simple Cycle	200	130.42	6.34	8.62	18.73	36.39	**200.49**	72.44	3.67	**76.12**	4.30	**280.91**
Conventional Combined Cycle (CC)	500	175.27	8.47	11.51	9.88	57.64	**262.77**	441.00	22.38	**463.38**	31.86	**758.01**
Conventional CC - Duct Fired	550	172.85	8.35	11.36	9.52	56.84	**258.91**	418.13	20.88	**439.01**	29.74	**727.66**
Advanced Combined Cycle	800	158.58	7.66	10.42	8.22	52.16	**237.04**	411.14	19.93	**431.07**	31.86	**699.97**
Coal - IGCC	300	466.89	24.52	33.34	60.03	-72.46	**512.31**	123.99	76.64	**200.63**	34.43	**747.38**
Biomass IGCC	30	358.17	22.94	30.36	173.91	-157.67	**427.71**	159.78	30.35	**190.13**	39.05	**656.89**
Biomass Combustion - Fluidized Bed Boiler	28	400.27	24.82	32.85	115.36	-151.09	**422.21**	179.73	38.30	**218.03**	43.26	**683.49**
Biomass Combustion - Stoker Boiler	38	326.41	20.27	26.83	185.62	-124.07	**435.06**	188.29	59.81	**248.09**	43.26	**726.41**
Geothermal - Binary	15	436.46	33.55	50.71	57.40	-252.00	**326.13**	0.00	30.61	**30.61**	71.21	**427.95**
Geothermal - Flash	30	398.51	30.72	46.44	70.64	-231.48	**314.83**	0.00	35.40	**35.40**	72.37	**422.60**
Hydro - Small Scale & Developed Sites	15	179.40	13.46	20.35	21.26	-89.61	**144.86**	0.00	9.30	**9.30**	11.49	**165.65**
Hydro - Capacity Upgrade of Existing Site	80	88.92	6.00	9.07	15.23	-1.70	**117.52**	0.00	6.39	**6.39**	11.49	**135.40**
Solar - Parabolic Trough	250	431.73	27.80	0.00	78.84	-192.27	**346.10**	0.00	0.00	**0.00**	30.60	**376.70**
Solar - Photovoltaic (Single Axis)	25	532.94	34.31	0.00	78.84	-237.12	**408.98**	0.00	0.00	**0.00**	30.60	**439.58**
Onshore Wind - Class 3/4	50	209.65	15.53	23.48	16.58	-101.60	**163.64**	0.00	19.58	**19.58**	20.12	**203.33**
Onshore Wind - Class 5	100	209.65	15.53	23.48	16.58	-101.61	**163.63**	0.00	22.22	**22.22**	22.84	**208.69**

Source: Energy Commission

Table B-5: Component Costs for IOU Plants (Nominal $/kW-Year)

In-Service Year = 2009 (Nominal 2009 $)	Size MW	$/kW-Yr (Nominal $) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	Transmission Cost	**Total Levelized Cost**
Small Simple Cycle	49.9	152.53	5.54	10.14	27.88	28.09	**224.18**	40.83	2.12	**42.95**	2.18	**269.31**
Conventional Simple Cycle	100	145.33	5.28	9.66	20.26	26.87	**207.40**	40.83	2.12	**42.95**	2.18	**252.53**
Advanced Simple Cycle	200	99.69	3.62	6.63	19.02	18.46	**147.41**	75.35	3.73	**79.08**	4.37	**230.86**
Conventional Combined Cycle (CC)	500	132.80	4.82	8.83	10.04	31.01	**187.50**	458.69	22.68	**481.37**	32.29	**701.17**
Conventional CC - Duct Fired	550	130.97	4.76	8.71	9.66	30.59	**184.68**	434.89	21.17	**456.06**	30.14	**670.88**
Advanced Combined Cycle	800	120.16	4.36	7.99	8.35	28.07	**168.93**	427.62	20.20	**447.83**	32.29	**649.05**
Coal - IGCC	300	385.06	13.99	25.60	60.96	-95.68	**389.93**	126.08	77.79	**203.87**	34.95	**628.75**
Biomass IGCC	30	362.16	13.16	24.08	174.67	-137.51	**436.55**	160.47	30.48	**190.95**	39.21	**666.72**
Biomass Combustion - Fluidized Bed Boiler	28	391.99	14.24	26.06	115.86	-148.64	**399.51**	180.47	38.46	**218.93**	43.44	**661.87**
Biomass Combustion - Stoker Boiler	38	320.12	11.63	21.28	186.43	-121.74	**417.72**	189.06	60.05	**249.11**	43.44	**710.28**
Geothermal - Binary	15	467.29	20.02	36.64	57.85	-208.10	**373.70**	0.00	30.41	**30.41**	71.30	**475.41**
Geothermal - Flash	30	427.88	18.33	33.55	71.19	-190.62	**360.33**	0.00	35.17	**35.17**	72.45	**467.95**
Hydro - Small Scale & Developed Sites	15	188.41	8.07	14.77	21.43	-71.70	**160.98**	0.00	9.30	**9.30**	11.49	**181.77**
Hydro - Capacity Upgrade of Existing Site	80	83.97	3.60	6.58	15.35	3.92	**113.43**	0.00	6.39	**6.39**	11.49	**131.31**
Solar - Parabolic Trough	250	439.57	15.97	0.00	79.18	-166.41	**368.31**	0.00	0.00	**0.00**	30.72	**399.04**
Solar - Photovoltaic (Single Axis)	25	542.46	19.71	0.00	79.18	-205.31	**436.04**	0.00	0.00	**0.00**	30.72	**466.76**
Onshore Wind - Class 3/4	50	217.37	9.31	17.04	16.71	-82.73	**177.70**	0.00	19.65	**19.65**	20.21	**217.56**
Onshore Wind - Class 5	100	217.37	9.31	17.04	16.71	-82.73	**177.69**	0.00	22.31	**22.31**	22.94	**222.94**

Source: Energy Commission

Table B-6: Component Costs for POU Plants (Nominal $/kW-Year)

		$/kW-Yr (Nominal $)										
In-Service Year = 2009 (Nominal 2009 $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Transmission Cost**	**Total Levelized Cost**
Small Simple Cycle	49.9	111.14	9.72	9.39	28.40	0.00	**158.64**	85.50	4.31	**89.81**	4.45	**252.90**
Conventional Simple Cycle	100	105.92	9.26	8.94	20.64	0.00	**144.76**	85.50	4.31	**89.81**	4.45	**239.02**
Advanced Simple Cycle	200	71.94	6.29	6.08	19.37	0.00	**103.67**	118.33	5.70	**124.03**	6.67	**234.37**
Conventional Combined Cycle (CC)	500	95.23	8.33	8.04	10.22	0.00	**121.82**	480.26	23.05	**503.31**	32.82	**657.95**
Conventional CC - Duct Fired	550	93.91	8.21	7.93	9.85	0.00	**119.89**	455.34	21.52	**476.86**	30.64	**627.39**
Advanced Combined Cycle	800	86.16	7.53	7.28	8.50	0.00	**109.48**	447.73	20.53	**468.27**	32.82	**610.57**
Coal - IGCC	300	276.53	24.18	23.35	62.10	0.00	**386.16**	128.57	79.21	**207.78**	35.59	**629.53**
Biomass IGCC	30	260.21	22.75	21.98	177.93	-15.42	**467.45**	163.44	31.04	**194.48**	39.93	**701.86**
Biomass Combustion - Fluidized Bed Boiler	28	281.95	24.65	23.81	118.03	-16.95	**431.48**	183.64	39.14	**222.78**	44.21	**698.48**
Biomass Combustion - Stoker Boiler	38	230.26	20.13	19.45	189.91	-17.32	**442.43**	192.38	61.12	**253.50**	44.21	**740.14**
Geothermal - Binary	15	289.58	33.17	31.86	60.31	-10.32	**404.60**	0.00	29.34	**29.34**	71.85	**505.80**
Geothermal - Flash	30	265.01	30.36	29.16	74.22	-10.73	**388.01**	0.00	33.94	**33.94**	72.96	**494.92**
Hydro - Small Scale & Developed Sites	15	119.60	13.70	13.16	22.34	0.00	**168.80**	0.00	9.31	**9.31**	11.50	**189.61**
Hydro - Capacity Upgrade of Existing Site	80	53.30	6.11	5.86	16.01	0.00	**81.28**	0.00	6.39	**6.39**	11.50	**99.17**
Solar - Parabolic Trough	250	317.58	27.77	0.00	80.66	-4.54	**421.47**	0.00	0.00	**0.00**	31.24	**452.71**
Solar - Photovoltaic (Single Axis)	25	391.91	34.27	0.00	80.66	-4.54	**502.30**	0.00	0.00	**0.00**	31.24	**533.55**
Onshore Wind - Class 3/4	50	137.82	15.79	15.16	17.42	-5.99	**180.19**	0.00	20.06	**20.06**	20.73	**220.99**
Onshore Wind - Class 5	100	137.82	15.79	15.16	17.42	-6.80	**179.39**	0.00	22.77	**22.77**	23.53	**225.69**

Source: Energy Commission

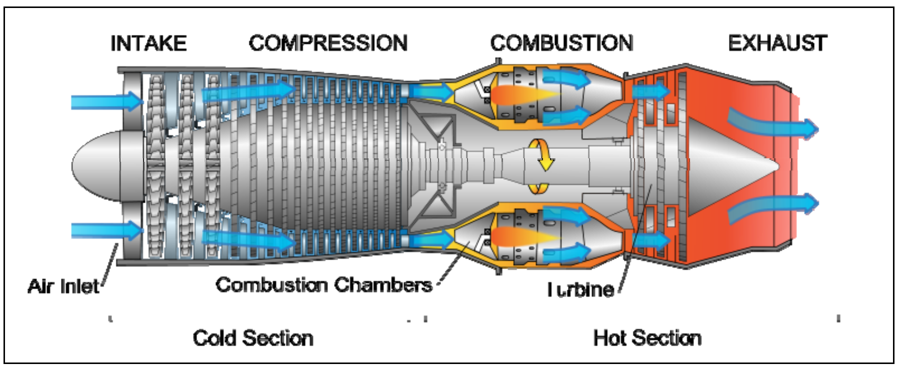
APPENDIX C: Gas-Fired Plants Technology Data

This appendix provides supporting information for the conventional and advanced gas-fired generation technology data assumptions provided in Chapter 2.

Conventional Simple Cycle

This technology is most commonly referred to as a combustion turbine or gas turbine. The combustion turbines included herein are aeroderivatives that were developed from the jet engines. They produce thrust from the exhaust gases, as illustrated **Figure C-1**.

Figure C-1: Aeroderivative Gas Turbine



Source: Wikipedia

F-Class gas turbines in simple cycle configuration are often used in other areas of the country, but there is not a single F-Class turbine currently operating in simple cycle mode in California, and due to the lower efficiency of the F-Class in simple cycle mode, such use in within California in the future is unlikely. Therefore, for the Model the most prevalent peaking turbine, the GE LM6000 gas turbine, is considered the basis for the two conventional simple cycle gas turbine cases.

Advanced Simple Cycle

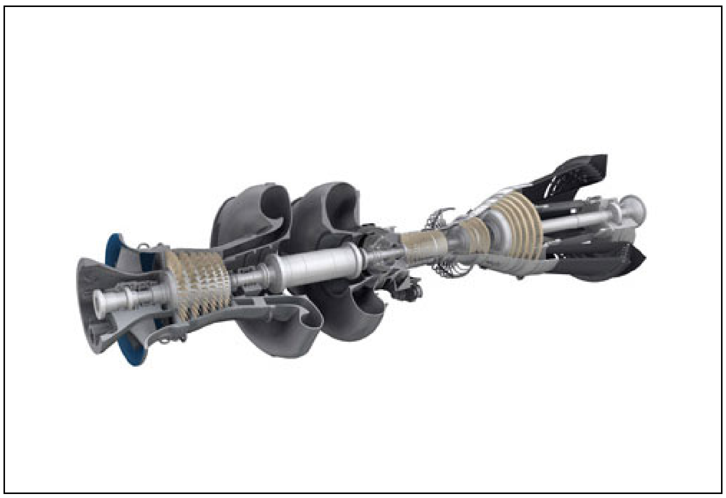
The advanced simple cycle gas turbine selected for evaluation is the GE LMS100 gas turbine. The LMS100, an aeroderivative gas turbine, provides increased power output due to the addition of an intercooling system. The intercooling system takes compressed air from the low-pressure compressor, cools it to optimal temperatures, and then redelivers it to the high-pressure compressor, reducing the work of compression and increasing the pressure ratio and mass flow through the turbine. In simple cycle applications, the LMS100 can achieve 44 percent thermal efficiency, which is an approximately 10 point improvement over other turbines in its size range[10].

Due to the intercooling systems the LMS100 requires significantly more cooling infrastructure than other aeroderivative gas turbines. This cooling can be accommodated by a wet cooling tower, a wet surface air condenser (WSAC), or an air-cooled condenser (ACC). The use of a wet cooling tower is assumed. **Figure C-2** provides a cross-section view of the LMS100 gas turbine.

Conventional Combined Cycle

This technology combines a conventional steam turbine with one or more simple cycle units to derive an outstanding level of efficiency. The exhaust heat of the simple cycle unit is used to heat steam in the heat recovery section that leads to the steam turbine, as shown in **Figure C-3**.

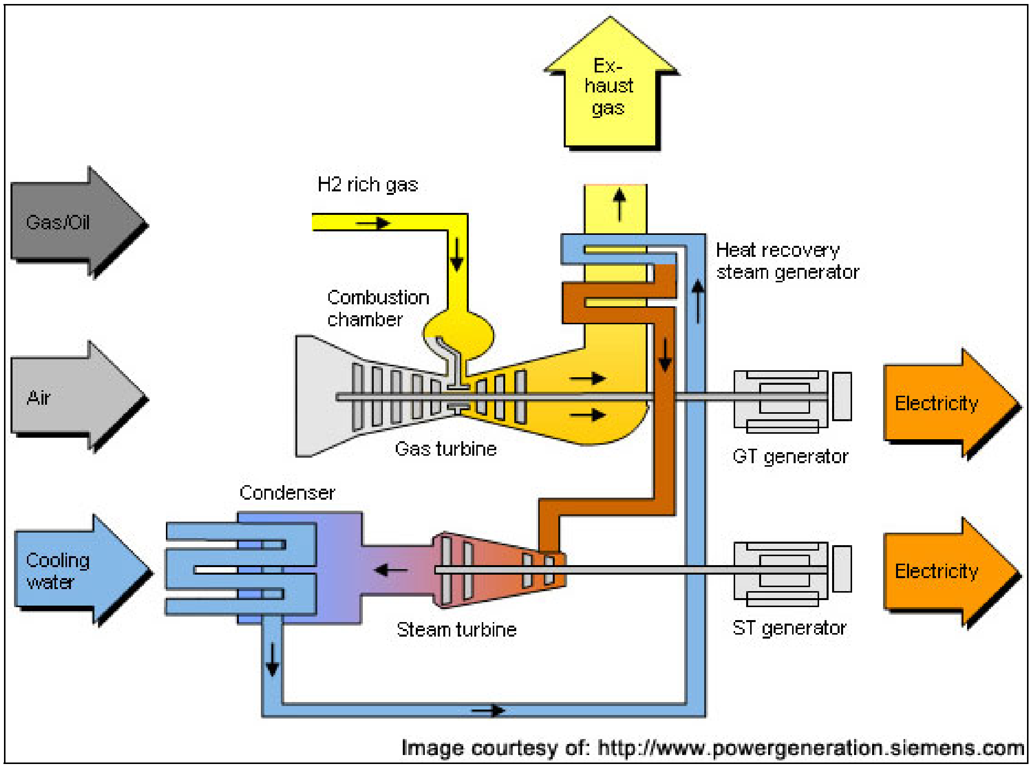
Figure C-2: LMS100 Gas Turbine



Source: http://ge.ecomagination.com/site/media/lms1/zoom-03.jpg

[10] Information extracted from http://ge.ecomagination.com/site/products/lms1.html.

Figure C-3: Combined Cycle Process Flow



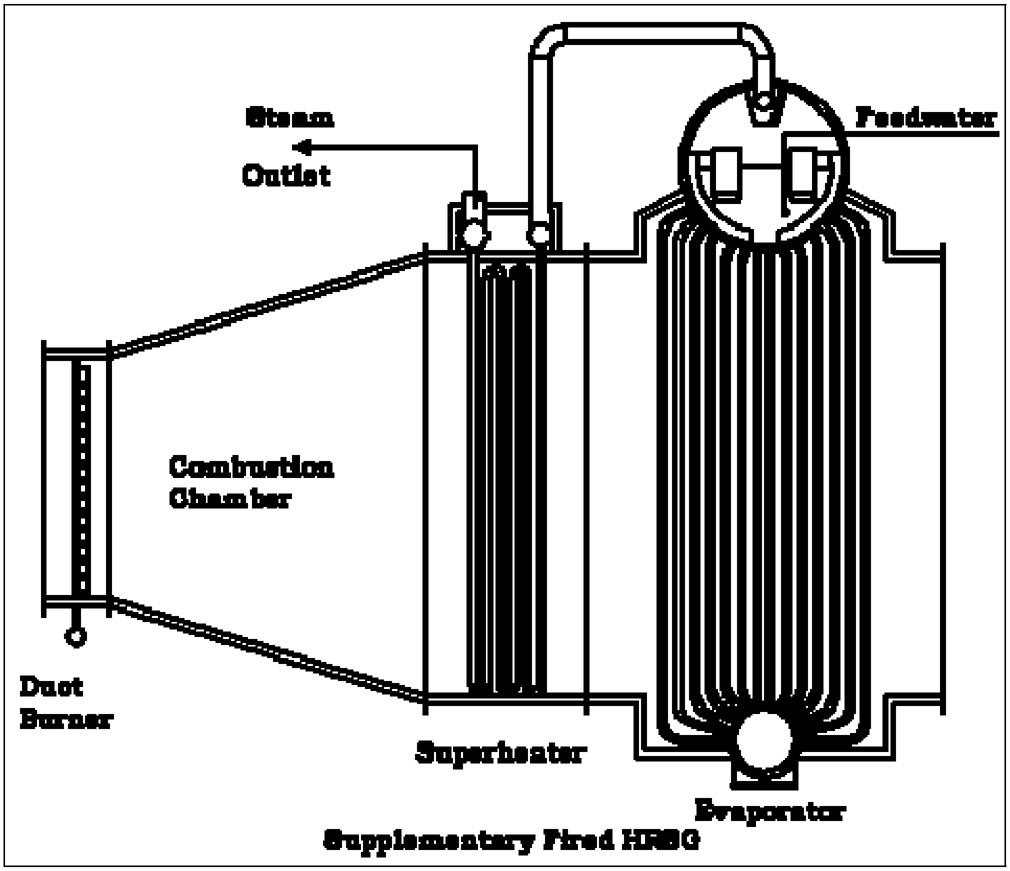
The typical combined cycle power plant built in California is based on the F-Frame gas turbine and typically includes two gas turbines and one steam turbine. However, the number of gas turbines and steam turbines vary significantly at the existing gas turbine combined cycle power plants in California. The general layout of a combined cycle power plant is provided in **Figure C-4**.

Figure C-4: Combined Cycle Power Plant General Arrangement

Conventional Combined Cycle With Duct Firing

Combined cycle systems can integrate duct burners after the gas turbine and before the heat recovery steam generator (HRSG) to increase power production. Duct firing affects power production only in the steam cycle portion of the combined cycle power generation and so is an inherently less efficient use of natural gas than the natural gas used to fire the gas turbine and make steam. Duct firing primarily provides peaking power and, if a plant's capacity factor is determined based on the total duct fired rating, will cause a corresponding decrease in the plant's annual capacity factor due to the limited use of the duct burners. The efficiency for duct firing, essentially the steam cycle efficiency, is similar to the efficiency of conventional simple cycle gas turbines but less efficient than advanced simple cycle gas turbines. The general layout of a combined cycle power plant HRSG, showing the added duct burners and combustion chamber on the far left, is provided in **Figure C-5**.

Figure C-5: Combined Cycle Power Plant HRSG Diagram

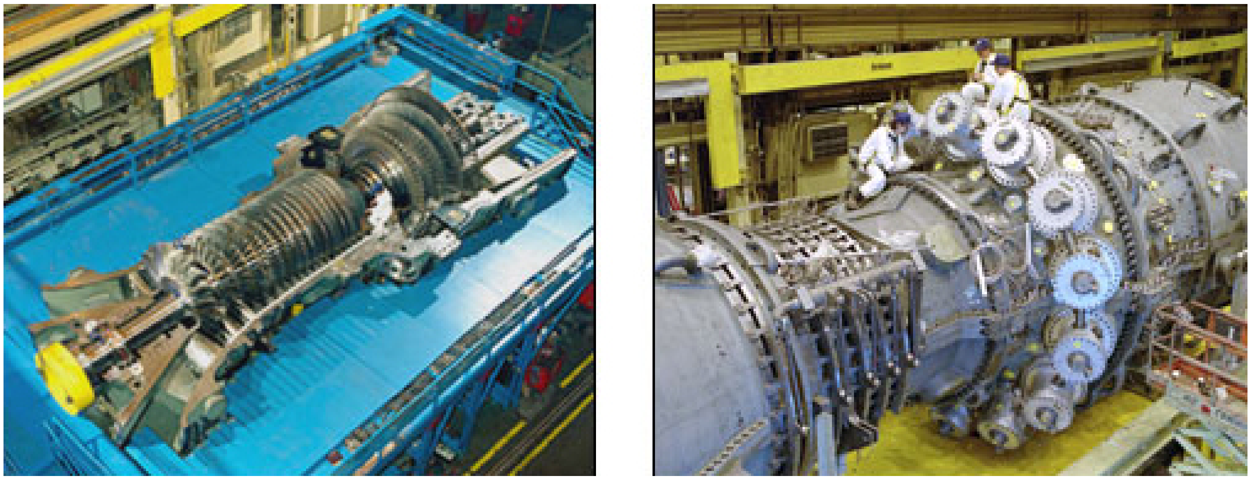


Source: http://www.nawabi.de/chemical/hrsg/HRSGimg5_9d.gif

Advanced Combined Cycle

The H System™ uses a closed-loop steam cooling system that allows the turbine to fire at a higher temperature to increase fuel efficiency to approximately 60 percent with reduced emissions and less fuel consumption per megawatt generated. This design also reduces the amount of cooling required per megawatt produced by the gas turbine, reducing the relative amount of necessary cooling infrastructure. **Figure C-6** shows an H-frame turbine during assembly and the outside of a completed H-frame gas turbine.

Figure C-6: GE H-Frame Gas Turbine



Source: http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/h_system/9h_photos.htm

Plant Data

Plant data are the plant characteristics of the selected conventional gas-fired technologies selected for implementation in the Model. This data generally has been collected by Commission staff and consultants for the *IEPR*. Other sources are noted where relevant.

Selection and Description of Technologies

Two categories of gas-fired technologies are included: simple cycle and combined cycle. The six gas turbine technology cases selected for inclusion in the Model have the following basic designs:

- Conventional Simple cycle – One LM6000 Gas Turbine
- Conventional Simple cycle – Two LM6000 Gas Turbines
- Advanced Simple cycle – Two LMS100 Gas Turbines
- Conventional Combined cycle – Two F-Class Turbines
- Conventional Combined cycle with Duct Burners – Two F-Class Turbines
- Advanced Combined cycle – Two H Class Turbines

In each conventional case, staff has provided the most common gas turbine technologies currently used or proposed for use California, and these conventional technologies are likely to be proposed and built in California into the near future. The configuration/size for the conventional technology power plants were selected based on their general prevalence in the existing power plant fleet.

Gross Capacity (MW)

The gross capacity assumed for six gas turbine technologies selected for implementation into the Model are provided in **Table C-1**.

Table C-1: Gross Capacity Ratings for Typical Configurations

Technology Case	Gross Capacity
Conventional SC – One LM6000 Turbine	49.9 MW
Conventional SC – One LM6000 Turbine	100 MW
Advanced SC – Two LMS100 Turbines	200 MW
Conventional CC (no duct burners) – Two F-Class Turbines	500 MW
Conventional CC (duct burners) – Two F-Class Turbines	550 MW
Advanced CC – Two H-Class Turbines	800 MW

Source: Energy Commission

The selected gross capacities assume that some form of air preconditioning is used to increase/stabilize the generating capacity while operating at high temperature and that the turbines are not significantly derated by operating at high elevation.

Combined and Simple Cycle Data Collection

The *2007 IEPR* analysis was the starting point for the analysis presented here. That analysis was updated to reflect either changed underlying costs (for example, inflation), or reanalysis of the original survey data to reflect further understanding gained since 2007. These costs were then supplemented with recent data and estimates from other sources such as government agencies, financial analysis institutions, and control area operators. Fuel use and operational data for California facilities were updated as well from the Commission's QFER database. Much of this analysis confirmed the underlying results from the *2007 IEPR*.

In preparing the *2007 IEPR*, staff submitted to power plant developers a data request for all the combined-2cycle (but not cogeneration) and simple cycle power plants that were certified by the Energy Commission starting in 1999 and on-line since 2001 through the first quarter of 2006. These plants are summarized in **Table C-2**, together with the in-service year and county location.

Table C-2: Surveyed Power Plants

Combined Cycle Plants (19)			Simple Cycle Plants (15)		
Plant Name	**County**	**Operating**	**Plant Name**	**County**	**Operating**
Los Medanos	Contra Costa	2001	Wildflower Larkspur [2]	San Diego	2001
Sutter	Sutter	2001	Wildflower Indigo [2]	Riverside	2001
Delta	Contra Costa	2002	Drews Alliance [2]	San Bernardino	2001
Moss Landing	Monterey	2002	Century Alliance [2]	San Bernardino	2001
La Paloma	Kern	2003	Hanford [2]	Kings	2001
High Desert	San Bernardino	2003	Calpeak Escondido [2]	San Diego	2001
MID Woodland [1,2]	Stanislaus	2003	Calpeak Border [2]	San Diego	2001
Sunrise	Kern	2003	Gilroy [2]	Santa Clara	2002
Blythe I	Riverside	2003	King City [2]	Monterey	2002
Elk Hills	Kern	2003	Henrietta	Kings	2002
Von Raesfeld [1]	Santa Clara	2005	Los Esteros	Santa Clara	2003
Metcalf	Santa Clara	2005	Tracy Peaker	San Joaquin	2003
Magnolia [1]	Los Angeles	2005	Kings River Peaker [1,2]	Fresno	2005
Malburg [1]	Los Angeles	2005	Ripon	San Joaquin	2006
Pastoria	Kern	2005	Riverside	Riverside	2006
Mountainview [3]	San Bernardino	2006			
Palomar	San Diego	2006			
Cosumnes	Sacramento	2006			
Walnut	Stanislaus	2006			

Notes:
1 – Muni-owned facility
2 – Emergency Siting or SPPE Cases
3 – IOU-owned facility

Source: Energy Commission

Capital cost information was requested from all 34 plants, while operating costs were requested from plants that began regular operations in 2005 or earlier. The data requests for the combined cycle and simple cycle units were divided into capital costs and operating and maintenance costs, as summarized in **Table C-3**.

Table C-3: Summary of Requested Data by Category

Capital Cost Parameters	Operating & Maintenance Cost Parameters
Gas Turbine and Combustor Make/Models	Total Annual Operating Costs
Steam Turbine Make/Model	Operating Hours
Total Capital Cost of Facility	Startup/Shutdown Hours
Gas Turbine Cost	Natural Gas Sources
Steam Turbine Cost	Duct Burner Natural Gas Use
Air Inlet Treatment Cost	Water Supply Source/Cost/Consumption
Cooling Tower/Air Cooled Condenser Cost	Labor (Staffing and Cost)
Water Treatment Facilities	Non-Fuel Annual Operating Costs (Consumables, etc.)
Site Footprint and Land Cost	Annual Regulatory Costs (Filings, Consumables, etc.)
Total Construction Costs (Labor/Equipment/etc.)	Major Scheduled Overhaul Frequency/Cost
Cost of Site Grading	Normal Annual Maintenance Costs
Cost of Pipeline Linear Construction	Reconciliation of QFER data (MW generation and total fuel use)
Cost of Transmission Linear Construction	
Cost of Licensing/Permitting Project	
Air Pollution Control Costs	
Cost of Air Quality Offsets	

Source: Energy Commission

The information request for each power plant was tailored according to the design of that plant. For example, simple cycle facilities did not include questions about steam turbines and duct burners. After receipt of the information requests responses, they were reviewed, and additional data or clarification of data was requested, as appropriate for each power plant, to complete and validate the information to the extent possible. As much of this data was gathered under confidentiality agreements, the details can be presented and discussed only in general, collective terms. Through spreadsheet analysis and comparison of relative costs as a function of various variables, it was possible to determine a suitable base cost plus adders to atypical configurations for the six categories described below.

No new or revised information requests were completed for the new power plants built or starting operation since the *2007 IEPR* information request. However, a large amount of additional capital and operating cost data was gathered through third-party sources, with the vast majority of this third party collected cost data coming from Jeff King of the Northwest Power and Conservation Council (NWPCC) and Stan Kaplan of the Congressional Research Service (CRS).

Outage Rates

Outages are divided into two categories, those that are foreseen or scheduled, and those that are unforeseen or forced. Outages differ from curtailments in that curtailments are considered to be caused by either discretionary choices (for example, responses to economic signals) or by resource shortages (for example, lack of fuel or renewable energy sources). Curtailments are represented in different ways elsewhere in the model.

The scheduled outage factor (SOF) was derived from National Electricity Reliability Council (NERC) GADS data for California generation resources:

- NERC GADS Vintage 2002-2007 CA CCs 500-900 MW: 6.02 percent
- NERC GADS 2002-2007 CA CTs 45-99 MW: 2.72 percent
- NERC GADS 2002-2007 CA CTs 100 and greater: 3.18 percent

Likewise, effective forced outage rates (EFOR and EFORd) were collected for California Generation Resources. The EFOR is measured against the period when the unit is operating, that is, it excludes non-operational hours due to curtailments when developing the rate. This is particularly important for low capacity factor resources such as simple cycle units. The EFORd values are used in the model.

- NERC GADS Vintage 2002-2007 CA CCs 500-900 MW EFORd: 3.5 percent (2.24 percent)
- NERC GADS 2002-2007 CA CTs 45-99 MW EFORd: 19.19 percent (5.65 percent)
- NERC GADS 2002-2007 CA CTs 100 and greater: EFORd: 11.60 percent (4.13 percent)

Capacity Factor (Percentage)

The actual capacity factors (CF) were determined for the existing California conventional LM6000 simple cycle power plants and F-Class combined cycle power plants, based on the monthly QFER data from 2001 to 2008 for 25 simple cycle facilities and 15 combined cycle facilities, and are provided in **Table C-4** and **Table C-5**. The capacity factors were derived using the following simple equation:

QFER net generation (MWh) /(facility generation capacity(MW) x hrs/year) = Capacity Factor

The combustion turbine units Anaheim, Glenarm, Grayson, Malaga, MID Ripon, Niland, and Riverside are publicly owned utilities (POUs); and Barre, Center, Etiwanda, and Mira Loma are investor-owned utilities (IOUs). The other power plants are all merchant facilities.

The capacity factors for the combined cycle units are based on the annual average duct-fired capacity for each facility. Magnolia and Cosumnes are POUs, and Palomar and Mountainview are IOUs. The other power plants are all merchant facilities.

The staff recommended capacity factors were determined by examination of historical capacity factor data in the Energy Commission's QFER database, as summarized in **Table** C-4 and **Table C-5** as well as an examination of production cost simulations. **Table** C-6 provides the average-cost, high-cost, and low-cost capacity factors that were recommended for use in the Model.

Table C-4: Simple Cycle Facility Capacity Factors

Year	Anaheim	Barre	Center	Creed	Etiwanda	Feather	Gilroy	Goose Haven	King City
2001	21.88%								
2002	29.90%						4.90%		3.90%
2003	25.41%			3.26%		3.66%	5.41%	3.10%	4.04%
2004	13.07%			2.39%		3.92%	5.65%	2.57%	4.99%
2005	12.29%			2.20%		3.03%	4.13%	2.46%	3.75%
2006	12.85%			2.66%		3.73%	4.21%	2.75%	3.80%
2007	11.45%	2.14%	1.90%	3.06%	1.61%	6.06%	7.21%	3.44%	5.43%
2008	12.04%	1.10%	1.10%	3.78%	0.86%	6.48%	7.77%	3.67%	5.77%

Year	Lambie	Riverview	Wolfskill	Yuba City	Glenarm	Grayson	Hanford	Henrietta	Indigo
2001							3.23%		
2002							4.89%	3.38%	0.33%
2003	3.24%	3.66%	3.85%	4.34%			2.24%	2.29%	5.86%
2004	3.69%	4.14%	5.01%	4.22%	5.43%	8.05%	1.20%	1.28%	6.28%
2005	3.62%	4.89%	3.74%	8.22%	2.78%	4.17%	3.95%	1.52%	4.71%
2006	2.80%	4.29%	3.96%	5.21%	4.97%	2.85%	2.62%	2.24%	4.40%
2007	3.47%	6.37%	4.87%	5.94%	4.50%	1.26%	4.43%	2.45%	6.86%
2008	3.51%	7.15%	6.14%	8.32%	4.07%	6.11%	5.69%	5.60%	9.90%

Year	Malaga	Larkspur	Los Esteros	MID Ripon	Mira Loma	Niland	Riverside
2001							
2002		1.18%	9.42%				
2003		4.01%	16.08%				
2004		4.74%	15.92%				
2005		3.85%	4.58%				
2006	7.58%	2.89%	3.87%	2.00%			7.53%
2007	15.52%	6.00%	4.79%	3.09%	1.72%		4.80%
2008	17.59%	8.02%	7.91%	3.85%	1.04%	9.21%	9.43%

Source: Energy Commission

Table C-5: Combined Cycle Facility Capacity Factors

Year	Magnolia	Moss Landing	High Desert	Sutter	Los Medanos	La Paloma	Delta	Sunrise
2001				32.1%	23.3%			
2002		28.4%		72.8%	76.4%		41.1%	
2003		57.9%	31.9%	62.9%	69.4%	34.6%	71.5%	32.3%
2004		55.5%	51.9%	67.3%	76.4%	57.2%	76.0%	62.1%
2005	10.8%	52.6%	50.3%	47.9%	76.8%	46.4%	72.8%	65.7%
2006	31.2%	57.7%	54.0%	41.5%	62.7%	57.0%	65.7%	70.2%
2007	49.4%	70.3%	61.1%	52.5%	74.4%	62.6%	71.6%	71.5%
2008	54.5%	62.2%	63.4%	57.1%	66.4%	62.6%	65.4%	70.2%

Year	Blythe	Metcalf	Mountainview	Pastoria	Elk Hills	Palomar	Consumnes
2001							
2002							
2003							
2004	26.8%				82.6%		
2005	19.6%	36.3%	1.6%	38.3%	74.4%		
2006	23.2%	44.9%	52.7%	70.6%	71.7%	51.7%	57.8%
2007	26.1%	55.4%	68.2%	73.5%	77.5%	69.9%	85.0%
2008	30.1%	61.4%	72.3%	74.6%	73.7%	75.1%	87.6%

Source: Energy Commission

Table C-6: Recommended Capacity Factors

Technology Case	Owner	Assumed Capacity Factor		
		Average	High	Low
Conventional Simple Cycle (both sizes)	Merchant/IOU	5%	2.5%	10%
	Muni	10%	3%	20%
Advanced Simple Cycle	Merchant/IOU	10%	5%	20%
	Muni	15%	10%	30%
Conventional Combined Cycle	All Owners	75%	55%	90%
Conventional Combined Cycle w/Duct Burners	All Owners	70%	50%	85%
Advanced Combined Cycle	All Owners	75%	55%	90%

Note: High and Low are based on cost implications not on the specific value of the capacity factor.

Source: Energy Commission

The advanced simple cycle capacity factors were increased somewhat from the assumed conventional simple cycle capacity factors due to an assumption of increased use due to higher efficiency. The advanced combined cycle capacity factors were assumed to be the same as the conventional non-duct-firing combined cycle capacity factors as these plants are presumed to replace conventional plants in the dispatch order.

There is a clear overall increase in both simple cycle and combined cycle capacity factor over the past few years in both the QFER and California ISO *Annual Report on Market Issues and Performance*. Therefore, the recommended capacity factors are higher than those used in the previous version of the Model.

Plant-Side Losses (Percentage)

The plant-side losses were estimated by analyzing the QFER data for the same facilities analyzed for capacity factor and heat rate. The plant-side losses, determined through the difference in the reported gross vs. reported net generation, for the existing California conventional LM6000 simple cycle power plants and F-Class combined cycle power plants, based on the monthly QFER data from 2001 to 2008 for 25 simple cycle facilities and 15 combined cycle facilities, are provided in **Table C-7**and **Table C-8**. Based on this data, staff recommends the average-cost, high-cost, and low-cost plant-side losses shown in **Table C-9**.

Staff does not have data to suggest significantly different plant side loss factors for advanced combined cycle facilities. The advanced simple cycle facilities may have increased plant-side losses due to the power required for the turbine inter-cooling auxiliary facilities; however, staff has no specific information to obtain values different from those determined for the LM6000 gas turbine facilities, so the same range is currently recommended.

Table C-7: Simple Cycle Facility Plant-Side Losses (%)

Anaheim	Barre	Center	Creed	Etiwanda	Feather	Gilroy	Goose Haven	King City
3.58%	n/a	n/a	3.62%	n/a	3.99%	3.05%	3.94%	4.15%
Lambie	**Riverview**	**Wolfskill**	**Yuba City**	**Glenarm**	**Grayson**	**Hanford**	**Henrietta**	**Indigo**
4.14%	3.14%	3.64%	4.19%	3.27%	3.39%	3.45%	2.91%	2.69%
Malaga	**Larkspur**	**Los Esteros**	**MID Ripon**	**Mira Loma**	**Niland**	**Riverside**		
2.33%	2.84%	3.40%	6.09%[a]	n/a	7.89%[a]	n/a		

Source: Energy Commission

Note:
[a] This data does not appear reasonable given the known plant design and was not used to determine the plant side losses recommended values.

Table C-8: Combined Cycle Facility Plant-Side Losses (%)

Magnolia	Moss Landing	High Desert	Sutter	Los Medanos	La Paloma	Delta	Sunrise
3.53%	3.34%	2.95%	3.80%	2.02%	3.23%	2.17%	3.10%
Blythe	**Metcalf**	**Mountainview**		**Pastoria**	**Elk Hills**	**Palomar**	**Consumnes**
n/a	2.15%	3.86%		2.84%	2.20%	2.56%	2.54%

Source: Energy Commission

Table C-9: Summary of Recommended Plant-Side Losses (%)

Technology	Average	High	Low
All Combined Cycle (CC)	2.9%	4.0%	2.0%
All Simple Cycle (SC)	3.4%	4.2%	2.3%

Source: Energy Commission

Heat Rate (Btu/kWh)

The actual heat rates, reported as higher heating value (HHV), determined for the existing California conventional LM6000 simple cycle power plants and F-Class combined cycle power plants , based on the monthly QFER data from 2001 to 2008 for 25 simple cycle facilities and 15 combined cycle facilities, are provided in **Table C-10** and **Table C-11.** The heat rates were derived using the following simple equation:

QFER heat input (MMBTU)/QFER net generation (kWh) = heat rate (Btu/kWh)

Table C-10: Simple Cycle Facility Heat Rates (Btu/kWh, HHV)

Year	Anaheim	Barre	Center	Creed	Etiwanda	Feather	Gilroy	Goose Haven	King City
2001	9,178								
2002	9,208						10,187		10,109
2003	9,325			10,124		9,578	10,341	10,095	10,075
2004	9,744			10,075		9,748	10,029	10,156	10,191
2005	10,170			10,170		9,448	9,970	10,175	10,259
2006	10,213			10,749		9,487	10,102	10,101	10,156
2007	9,499	11,744	10,640	10,251	11,051	10,308	10,073	10,358	9,749
2008	9,424	12,057	10,587	10,247	12,062	10,258	10,125	10,304	9,862

Year	Lambie	Riverview	Wolfskill	Yuba City	Glenarm	Grayson	Hanford	Henrietta	Indigo
2001							10,295		
2002							10,263	10,177	10,091
2003	9,953	10,235	9,942	9,710			10,279	10,263	10,236
2004	10,089	10,015	10,150	9,549	11,969	11,510	10,127	10,419	10,061
2005	10,169	10,069	10,297	9,452	12,434	11,548	10,675	10,582	10,137
2006	10,317	11,585	10,154	9,338	10,226	11,885	10,220	10,291	10,154
2007	10,145	10,101	10,319	10,071	10,439	12,322	10,798	10,491	9,934
2008	10,152	10,217	10,208	10,051	10,604	11,522	10,137	10,434	10,000

Year	Malaga	Larkspur	Los Esteros	MID Ripon	Mira Loma	Niland	Riverside
2001							
2002		9,972	10,345				
2003		10,065	10,275				
2004		10,011	10,404				
2005		10,236	10,480				
2006	9,470	10,208	10,309	12,749			9,526
2007	9,999	10,047	10,346	12,494	11,138		9,372
2008	9,957	10,019	10,708	11,629	11,992	10,257	9,528

Source: Energy Commission

Table C-11: Combined Cycle Facility Heat Rates (Btu/kWh, HHV)

Year	Magnolia	Moss Landing	High Desert	Sutter	Los Medanos	La Paloma	Delta	Sunrise
2001				6,982	6,947			
2002		7,136		7,089	7,090		7,295	
2003		7,081	7,321	7,156	7,239	7,198	7,310	7,524
2004		7,069	7,348	7,193	7,191	7,133	7,289	7,213
2005	7,614	7,099	7,356	7,458	7,290	7,234	7,288	7,206
2006	7,340	7,052	7,343	7,451	7,337	7,167	7,324	7,295
2007	7,456	7,084	7,047	7,406	7,210	7,166	7,317	7,274
2008	7,233	7,127	7,055	7,430	7,218	7,172	7,321	7,266
Year	**Blythe**	**Metcalf**	**Mountainview**		**Pastoria**	**Elk Hills**	**Palomar**	**Consumnes**
2001								
2002								
2003								
2004	7,416					6,855		
2005	7,419	7,028			7,230	6,990		
2006	7,436	7,048	7,252		7,050	7,051	7,069	7,198
2007	7,825	7,042	7,063		7,062	7,050	7,038	7,042
2008	7,808	6,884	7,141		7,032	7,063	6,959	7,047

Source: Energy Commission

Table C-12 provides the average-cost, high-cost, and low-cost heat rates that were recommended for use in the Model. These values are higher (in other words, less efficient) than those reported by manufacturers and often used in other studies because these values include real-world operations such as start-ups and load following.

The advanced turbine technology heat rates were determined using data from turbine manufacturers and from the Energy Information Administration (EIA) 2006 forecast.

Table C-12: Summary of Recommended Heat Rates (Btu/kWh, HHV)

Technology	Average [a]	High [a]	Low [b]
Conventional Simple Cycle (SC) [c]	9,266	10,000	9,020
Advanced SC	8,550	8,700	8,230
Conventional Combined Cycle (CC)	6,940	7,200	6,600
Conventional CC W/ Duct Firing	7,050	7,400	6,700
Advanced CC	6,510	6,710	6,310

Notes:
[a] Average and High cost recommended values are based on an analysis of average and high QFER heat rates and current turbine technology (for example the average heat rate for the conventional simple cycle is based on new projects installing the next generation of LM6000 gas turbine). [b] Low cost recommended values are based on new and clean heat rates from turbine manufacturers. Average heat rates in COG Model are presented as a regression formula based on QFER data.[c] The conventional simple cycle values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases and are based on NXGen LM6000 gas turbine efficiencies that are higher than most of the existing LM6000-powered plants.
Source: Energy Commission

Heat Rate Degradation

Heat rate degradation is the percentage that the heat rate will increase per year. For this report, the heat rate degradation estimates are:

- For simple cycle units: 0.05 percent per year.
- For combined cycle units: 0.2 percent per year.

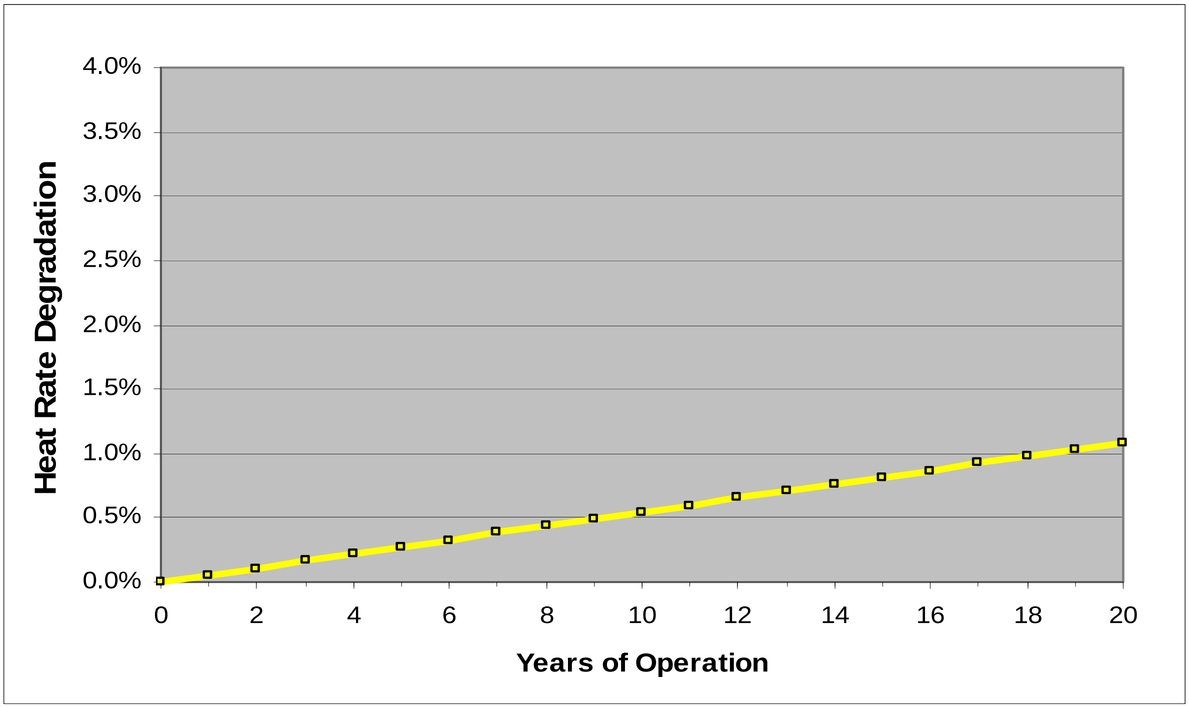
These values were estimated using General Electric data provided under the Aspen data survey. The rule for simple cycle units (combustion turbines) is that they degrade 3 percent between overhauls, which is every 24,000 hours. The actual time between overhauls, therefore, is a function of capacity factor as shown in **Table C-13**. The staff elected to use a 5 percent capacity factor based on the capacity factors observed in the survey data, and calculated degradation of 0.05 percent per year. **Figure C-7** shows the results, designated as "Equivalent SC Degradation."

Table C-13: Annual Heat Rate Degradation vs. Capacity Factor

Technology	Assumed Capacity Factor	Years Between Overhauls
Simple Cycle Units	5%	N/A
Simple Cycle Units	10%	27
Combined Cycle Units	50%	5.5
Combined Cycle Units	60%	4.6
Combined Cycle Units	70%	3.9
Combined Cycle Units	80%	3.4

Source: Energy Commission

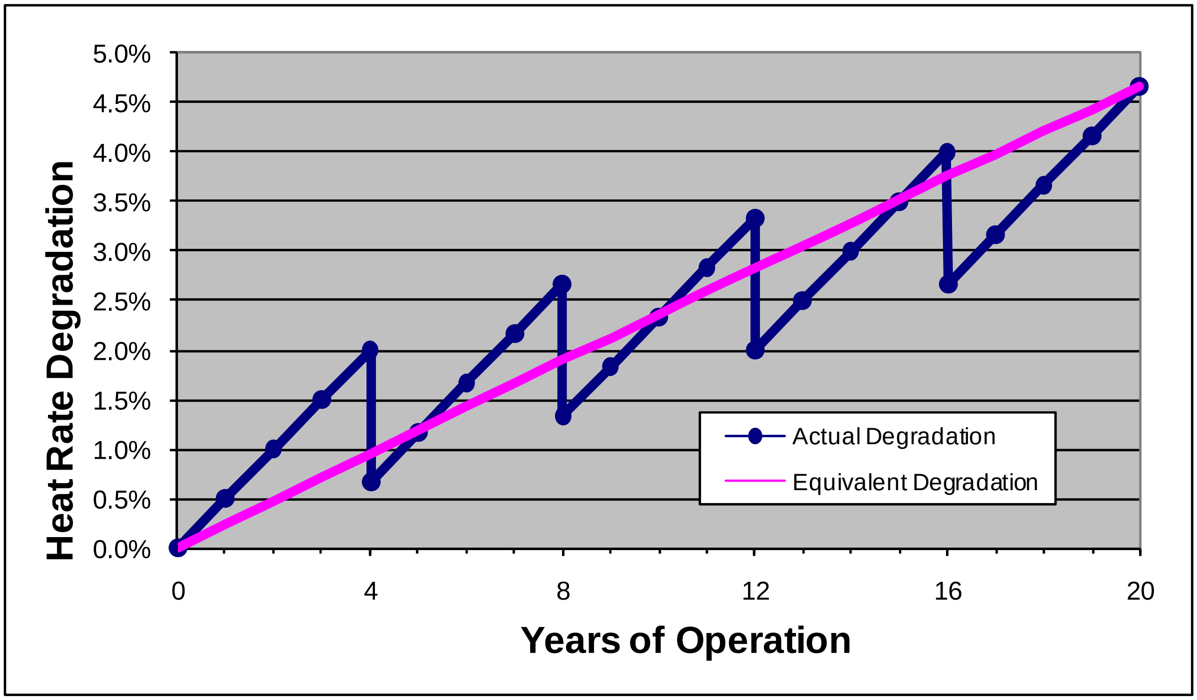
Figure C-7: Simple Cycle Heat Rate Degradation



Source: Energy Commission

The computation for the combined cycle units is more complex due to its higher capacity factor, estimated herein to be roughly 75 percent and 70 percent for a duct-fired unit, based on the QFER data and other historical information. The staff simplified this assumption by using four years for both technologies. This results in 4 major overhauls during its 20-year book life, as shown in **Figure C-8**. This means that the simple cycle units will degrade 3 percent during that period. Since the steam generator portion is essentially 1/3 of the system and remains essentially stable, and the overall system deteriorates 2/3 of the 3 percent of the simple cycle during the 4-year period, which is 2 percent; and recovers 2/3 of its 2 percent deterioration during the overhaul, which is 1 and 1/3 percent (2/3*2 = 4/3% = 1 1/3%). The degradation factor is equal to the slope of the curve, 0.24 percent per year. Since this factor has a small effect on levelized cost, this approximation is quite adequate. The details of this can be found in the Model User's Guide.

Figure C-8: Combined Cycle Heat Rate Degradation



Source: Energy Commission

Capacity Degradation

This value captures the degradation of capacity averaged over the life of the power plant It accounts for both the degradation of capacity due to wear and tear and the improvement in capacity due to periodic overhauls. It is an average as the plant capacity degrades and then is improved due to the many overhauls the plant experiences during its lifetime. Capacity Degradation is provided as an annual percentage. For the combined cycle and simple cycle units, the capacity degradation value is assumed to be equal to the heat rate degradation percentages.

The implementation of the capacity degradation factor is done by making two simplifying assumptions. The first assumption is that the capacity degradation can be ignored in the calculation of $/kW-Yr of the Income Statement Worksheet, based on the assumption that the $/kW-Yr should be considered to be based on the original installed gross capacity, similar to installed cost. That is, it should not be based on the average value of the degraded capacity (for example, the geometric mean of time-weighted capacities over the study period). It is captured only on the energy side.

The second assumption is that the impact on the energy generated can be represented by a constant annual average value, rather than as actual annual values that decrease over the years.

In each case, an average energy value (PMT) is calculated by first calculating a present value (PV) of the actual energy values and then using that PV to find the levelized energy value (PMT), similar to what is done in the Income Statement Worksheet for dollar values. This calculation of the PV is subtle and can best be illustrated using simplified nomenclature. If E_t are 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 present value (PV) of the entire series, therefore, can be represented as:

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

This can be easily rearranged to:

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

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

$$PV = \sum_{t=1}^{N} \frac{E_C}{[1+(1+DR)/(1-CD)-1]^t} = \sum_{t=1}^{N} \frac{E_C}{(1+i)^t}; where: \quad i = [(1+DR)/(1-CD)]-1$$

The formula is now a present value of constant value E_C, where the interest rate is equal to $[(1+DR)/(1-CD)]-1$.

Emission Factors

The criteria pollutant emission factors for the six gas turbine cases were estimated using permitted emission data from the following recent Energy Commission siting cases:

- Conventional CT (both cases) – Riverside Energy Resource Center Units 3 and 4
- Advanced CT – Panoche Energy Center
- Conventional CC (no duct firing) – Carlsbad Energy Center
- Conventional CC (duct firing) – Avenal Energy
- Advanced CC – Inland Empire Energy Center

The criteria pollutant emission factors recommended by staff for use in the Model based on these recent projects are provided in **Table C-14**.

The criteria pollutant emissions are based on permitted rather than actual emissions; therefore, average, high, and low values do not apply as the permitted emissions are assumed to be related to a consistent interpretation of Best Available Control Technology requirements within California.

The carbon dioxide emission factors were determined based on the efficiency for each technology based on an emission factor of 52.87 lb/MMBtu.[11] **Table C-15** provides the staff recommended carbon dioxide emission factors for each technology case based on the recommended heat rates shown in **Table C-12** .

Table C-14: Recommended Criteria Pollutant Emission Factors (lbs/MWh)

Technology	NO_x	VOC	CO	SO_x	PM10
Conventional Simple Cycle (SC) [a]	0.279	0.054	0.368	0.013	0.134
Advanced SC	0.099	0.031	0.190	0.008	0.062
Conventional Combined Cycle (CC)	0.070	0.208	0.024	0.005	0.037
Conventional CC w/Duct Firing	0.076	0.315	0.018	0.009	0.042
Advanced CC	0.064	0.018	0.056	0.005	0.031

Notes:
[a] The conventional simple cycle values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

Source: Energy Commission

Table C-15: Recommended Carbon Dioxide Emission Factors (lbs/MWh)

Technology	Average	High	Low
Conventional Simple Cycle (SC) [a]	1,080	1,166	1,052
Advanced SC	997	1,014	959
Conventional Combined Cycle (CC)	815	839	769
Conventional CC w/Duct Firing	825	863	781
Advanced CC	759	782	736

Notes:
[a] The conventional simple cycle values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

Source: Energy Commission

[11] Emission factor is from the California Air Resources Board for natural gas with an assumed heating content (HHV) between 1,000 and 1,025 Btu/scf.

Plant Cost Data

The plant costs data were obtained from surveys conducted for the *2007 IEPR* and from project cost data obtained through research conducted by third parties.[12]

Instant and Installed Capital Costs

The plant cost data is now identified for average, high, and low cost cases; therefore the specificity of the design has been simplified. All projects are assumed to have selective catalytic reduction (SCR) for control of nitrogen oxides emissions and an oxidation catalyst for control of carbon monoxide emissions. **Table C-16** indicates how the following design considerations generally drive the plant capital costs:

Table C-16: Plant Design Factors vs. Capital Cost Implications

Plant Design Factor	High	Low
Larger Project (MW)		S
Bay Area Project	S	
Los Angeles Area Project	S	
Non-Urban Site		W
Co-Located W/ Other Power Facilities		S
Linear Interconnection Distances	W	
Wet Cooling		W
Dry Cooling	W	
Greenfield Site		W
Brownfield Site (uncontaminated)	W	
Reclaimed Water Source		
Evaporative Coolers/Foggers	W	
Inlet Air Chiller	W	
Zero Liquid Discharge	W	

Note: S – Strong correlation, W - Weak correlation

Source: Energy Commission

[12] Additional power plant project cost data obtained from Jeff King of NWPCC and Stan Kaplan of CRS.

Capital Cost Analysis Method

All costs were corrected for a California power plant in 2009 dollars. The power plant cost estimates from the various reference sources were corrected to 2009 dollars using the following calculation method:

(Raw Cost) x (Relative State Costs[13]) x (Capital Cost Yearly Index[14]) x (Project size correction factors) x (adjustment for Installed/Instant Costs) = Adjusted Instant Capital Cost in 2009$

Where:

Raw Cost = Announced instant cost or as-built installed cost depending on the project from ***Table C-21***

Relative State Cost = California Index/Index for project location, see below for state factors

Capital Cost Yearly Index = see below for Power Plant Cost Index

Project size corrections = 2007 IEPR number of turbines/MW corrections indexed to 2009

Installed/Instant Cost Adjustment – 9.8 percent based on known announced vs. as-built costs

Table C-17 provides the Army Corps of Engineers' (ACOE) state construction cost adjustment factors.

Table C-17: State Adjustment Factors

State	Index	State	Index	State	Index	State	Index	State	Index
AL	0.90	HI	1.18	MA	1.18	NM	0.94	SD	0.87
AK	1.21	ID	0.97	MI	1.04	MY	1.15	TN	0.87
AZ	0.95	IL	1.11	MN	1.15	NC	0.84	TX	0.86
AR	0.88	IN	1.00	MS	0.89	ND	0.92	UT	0.94
CA	**1.18**	IA	0.96	MO	1.02	OH	1.04	VT	0.96
CO	0.98	KS	0.94	MT	0.96	OK	0.85	VA	0.96
CT	1.20	KY	0.98	NE	0.97	OR	1.09	WA	1.07
DE	1.12	LA	0.88	NV	1.09	PA	1.09	WV	1.03
FL	0.91	ME	0.98	NH	1.05	RI	1.15	WI	1.07
GA	0.89	MD	0.98	NJ	1.20	SC	0.85	WY	0.91

Source: ACOE, March 2008 (note 2009 values have been published but, due to at least one apparent major error in the 2009 index, the 2008 index has been used in this evaluation).

Table C-18 presents the power plant construction cost index that is primarily based on information from Cambridge Energy Research Associates (CERA).

[13] The ACOE state cost index.

[14] The CERA power plant construction cost index.

As can be seen there was a power plant cost factor increase higher than inflation starting as early as 1998 with a more significant power plant cost factor increase from 2004 to 2008 that has begun to reverse recently based on recent Producers Price Index (PPI) data.

The power plant size, economy of scale, was adjusted for combined cycle plants using a factor for the number of turbines as determined in the *IEPR* and adjusted by the power plant cost index to 2009 dollars; and an additional adjustment for duct firing size was also made to adjust to the no-duct firing case and the 50 MW duct firing case. Finally for simple cycle projects an adjustment for project size was made, again using the *2007 IEPR* values adjusted using the power plant cost index to 2009 dollars. A summary of these project size adjustments is provided in **Table C-19.**

Table C-18: Power Plant Cost Index

Year	Index	Year	Index
1998	0.91	2004	1.24
1999	0.95	2005	1.37
2000	1	2006	1.56
2001	1.05	2007	1.71
2002	1.11	2008	1.82
2003	1.17	2009	1.75

Source: CERA 2008, with 2009 also based on evaluation of PPI Index.

Table C-19: Project Capital Cost—Size/Design Adjustments

Project Design Factor	Cost Adjustment
CC – Number of Turbines [a]	$103.5 +/- for each gas turbine -/+ 2 turbines
CC – Duct Firing	Add $255 x duct firing MW fraction of total MW
SC – Project Size	$1.55 +/- per MW -/+ 96 MW
Advanced SC – Project Size	$103.5 +/- for each gas turbine -/+ 2 turbines

Note:
[a] Applies to Advanced CC case as well and is valid from 1 to 4 turbines.
[b] Uses CC value with MW ratio of LMS100 to F-Frame turbine.

Source: Energy Commission

Combined Cycle Capital Costs

Table C-20 provides the assumed design configuration of the three combined cycle cases**.**

The projects with announced instant or as-built installed cost data that were evaluated to determine the recommended average, high, and low capital cost values for the three combined cycle cases are shown in **Table C-21**.

All of the advanced turbine projects are G-frame turbines; however, no G-frame turbine projects have been proposed in California as of May 2009. The Application for Certification (AFC) level data available for the Inland Empire H-frame turbine project is not considered reasonable or representative, given the known problems during the construction of that project; so it was not used.

Table C-20: Base Case Configurations—Combined Cycle

500 MW Combined Cycle Base Configuration
1) 500 MW Plant W/O Duct Firing 2) Two F-Frame Turbines W/One Steam Generator
550 MW Combined Cycle Base Configuration
1) 500 MW Plant W/Duct Firing 2) Two F-Frame Turbines W/One Steam Generator 3) 50 MW of Duct Firing
800 MW Advanced Combined Cycle Base Configuration
1) 800 MW Plant W/O Duct Firing 2) Two H-Frame Turbines W/Single Shaft Generators

Source: Energy Commission

Table C-21: Raw Installation Cost Data for Combined Cycle Projects

Project Name	State	Size (MW)	Raw Cost ($/kW)	Year	As-Built? (Y/N)
Conventional F-Frame Projects					
Arlington Valley	AZ	570	$439	2001	N
Arrow Canyon	NV	500	$540	2000	N
Arsenal Hill	LA	454	$610	2006	N
Avenal Power Center	CA	600	$883	2008	N
Bighorn	NV	591	$863	2008	N
Blythe Energy Project I	CA	520	$673	2004	Y
Blythe Energy Project II	CA	520	$481	2002	N

Project Name	State	Size (MW)	Raw Cost ($/kW)	Year	As-Built? (Y/N)
Cane Island Combined Cycle	FL	300	$1,167	2008	N
Chuck Lenzie (ex Moapa) Phase I	NV	580	$481	2004	N
Chuck Lenzie (ex Moapa) Phase II	NV	580	$481	2004	N
Colusa	CA	657	$1,024	2008	N
Community Power Plant	CA	565	$775	2008	N
Coyote Springs	OR	261	$691	2001	N
Current Creek	UT	525	$659	2006	N
Front Range Power	CO	480	$535	2002	N
Gateway (ex Contra Costa 8)	CA	530	$698	2007	N
Goldendale Energy Center	WA	277	$531	2001	N
Grays Harbor Energy Center	WA	650	$462	2001	N
Greenland Energy Center	FL	553	$1,085	2008	N
Harquahala	AZ	1000	$400	2000	N
Harry Allen CC	NV	500	$1,364	2008	N
Hines Unit 4	FL	461	$491	2006	N
Lake Side	UT	534	$650	2006	N
Langley Gulch	ID	330	$1,295	2009	N
Luna Energy Facility (formerly Deming)	NM	570	$439	2002	N
Mesquite	AZ	1250	$400	2000	N
Mirant Willow Pass	CA	550	$1,064	2008	N
Otay Mesa	CA	510	$539	2002	N
Port Washington Generating Station Unit 1	WI	510	$611	2002	N
Port Washington Generating Station Unit 2	WI	545	$580	2002	N
Richmond County	NC	600	$1,208	2008	N
Rocky Mountain Energy Center	CO	621	$580	2001	N
San Gabriel	CA	656	$793	2007	N
Silverbow	MT	500	$680	2002	N
Silverhawk	NV	570	$702	2002	N
Tesla (Original FPL)	CA	1120	$625	2001	N
Tesla (PG&E proposal)	CA	560	$1,518	2008	N
Thetford	MI	639	$815	2007	N
Tracy CC (SPP)	NV	541	$778	2008	Y

Project Name	State	Size (MW)	Raw Cost ($/kW)	Year	As-Built? (Y/N)
Treasure Coast Energy Center	FL	291	$884	2008	N
West Phoenix 5	AZ	530	$415	2000	N
Mountainview	CA	1054	Confidential	2006	Y
Palomar	CA	546	Confidential	2006	Y
Blythe	CA	520	Confidential	2003	Y
Delta	CA	882	Confidential	2002	Y
Elk Hills	CA	550	Confidential	2003	Y
High Desert	CA	830	Confidential	2003	Y
La Paloma	CA	1080	Confidential	2003	Y
Los Medanos	CA	566	Confidential	2001	Y
Metcalf	CA	600	Confidential	2005	Y
Moss Landing	CA	1060	Confidential	2002	Y
Pastoria	CA	750	Confidential	2005	Y
Sunrise	CA	585	Confidential	2003	Y
Sutter	CA	543	Confidential	2001	Y
Cosumnes	CA	500	Confidential	2006	Y
Magnolia	CA	310	Confidential	2005	Y
Advanced Turbine Projects					
Cape Canaveral Energy Center	FL	1219	$817	2008	N
Port Westward	OR	399	$719	2006	Y
West County Energy Center Unit 1	FL	1219	$510	2006	N
West County Energy Center Unit 2	FL	1219	$462	2006	N
West County Energy Center Unit 3	FL	1219	$638	2008	N
Riviera Beach Energy Center	FL	1207	$935	2008	N

Source: Energy Commission, NWPCC, CRS

Table C-22 shows the recommended instant costs for the three combined cycle cases in the Model.

There are two factors of concern regarding these recommended cost values. First, the reduction in the cost index from 2008 to 2009 has a lower level of confidence than the other annual index values; and second, the Advanced CC case cost is based on very limited data for a different advanced gas turbine type. However, it is reasonable to have an economy of scale reduction in cost that is, somewhat muted for the Advanced CC case, based on increased project generation capacity.

Table C-22: Total Instant/Installed Costs for Combined Cycle Cases

Combined Cycle Case (Nominal 2009$)	Average ($kW)	High ($kW)	Low ($kW)
Conventional 500 MW CC without Duct Firing	$1,044	$1,349	$777
Conventional 550 MW CC with Duct Firing	$1,021	$1,325	$753
Advanced 800 MW CC without Duct Firing	$957	$1,218	$759

Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.

Source: Energy Commission

Simple Cycle Capital Costs

Table C-23 provides the assumed design configuration of the three simple cycle cases**.**

The projects with announced instant or as-built installed cost data that were evaluated to determine the recommended average, high, and low capital cost values for the three simple cycle cases are shown in **Table C-24**.

Table C-23: Base Case Configurations—Simple Cycle

49.9 MW Simple Cycle Base Configuration
1) 49.9 MW Plant 2) One LM6000 Gas Turbine w/Chiller Air Pretreatment
100 MW Simple Cycle Base Configuration
1) 100 MW Plant 2) Two LM6000 Gas Turbines w/Chiller Air Pretreatment
200 MW Advanced Simple Cycle Base Configuration
1) 200 MW Plant 2) Two LMS100 Gas Turbines w/Evaporative Cooler Air Pretreatment

Source: Energy Commission

Table C-24: Raw Cost Data for Simple Cycle Projects

Project Name	State	Size (MW)`	Raw Cost ($/kW)	Year	As-Built? (Y/N)
Conventional LM6000 Gas Turbine Projects					
Agua Mansa	CA	43	$1,000	2002	N
Almond Expansion	CA	150	$1,333	2008	N
Apache Station	NV	40	$750	2001	N
Barre	CA	47	$1,409	2007	Y
Black Mountain	AZ	90	$694	2007	N
Burbank GT	CA	50	$706	2000	N
Canyon Power Plant	CA	194	$1,082	2008	N
Center	CA	47	$1,409	2007	Y
Feather River Energy Center	CA	45	$889	2001	N
Gadsby 4-6	UT	120	$628	2001	N
Grapeland	CA	47	$1,409	2007	Y
Mira Loma	CA	47	$1,409	2007	Y
Miramar	CA	46	$705	2004	Y
MMC Chula Vista	CA	94	$851	2007	N
MMC Escondido	CA	47	$1,064	2008	N
Orange Grove	CA	96	$885	2007	N
Pyramid 1-4	NM	168	$706	2002	N
San Francisco Peaking Plant	CA	193	$1,399	2008	N
San Francisco Potrero Plant	CA	145	$966	2004	N
Yucca GT 5 & GT 6	AZ	96	$802	2008	N
Henrietta	CA	96	Confidential	2002	Y
Hanford	CA	95	Confidential	2001	Y
Gilroy	CA	135	Confidential	2002	Y
King City	CA	45	Confidential	2002	Y
Kings River	CA	96	Confidential	2005	Y
Ripon	CA	95	Confidential	2006	Y
Riverside	CA	96	Confidential	2006	Y
LMS100 Advanced Gas Turbine Projects					
Groton 1	SD	95	$726	2006	Y
Panoche Energy Center	CA	400	$750	2008	N
Sentinel CPV Ph I	CA	728	$604	2007	N
Walnut Energy Park	CA	515	$544	2007	N

Source: Energy Commission, NWPCC, CRS

Table C-25 shows the recommended instant costs for the three combined cycle cases in the Model.

Table C-25: Total Instant/Installed Costs for Simple Cycle Cases

Simple Cycle Case (Nominal 2009$)	Average ($/kW)	High ($/kW)	Low ($/kW)
Conventional 49.9 MW SC	$1,277	$1,567	$914
Conventional 100 MW SC	$1,204	$1,495	$842
Advanced 200 MW SC	$801	$919	$693

Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.

Source: Energy Commission

There are two factors of concern regarding these recommended cost values. First, the reduction in the cost index from 2008 to 2009 has a lower level of confidence than the other annual index values. Second, the Advanced SC case cost is based on very limited data for a different advanced gas turbine type. The significantly lower cost for the Advanced SC case seems to overstate the potential for economy of scale reduction in cost, particularly since the LMS100 technology requires an increase in auxiliary equipment costs. Therefore, there is a low level of confidence with the Advanced SC costs.

Construction Periods

The staff-recommended construction periods for use in the Model are based on an analysis of the facilities surveyed for the *2007 IEPR* and other known project construction periods. **Table C-26** provides the average-cost, high-cost, and low-cost heat rates that were recommended for use in the Model.

Table C-26: Summary of Recommended Construction Periods (months)

Technology	Average	High	Low
Conventional Combined Cycle (CC)	26	36	20
Conventional CC W/ Duct Firing	26	36	20
Advanced CC	26	36	20
Conventional Simple Cycle (SC) [a]	9	16	4
Advanced SC [b]	15	20	12

Note:
[a] The conventional simple cycle values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.
[b] Engineering estimate using the anticipated 18-month Panoche case construction duration as slightly higher than average value due to it being a four-turbine project rather than a two- turbine project.

Source: Energy Commission

Construction periods can be influenced by many factors, including greenfield or brownfield sites, the overall complexity of the design of the facility, the constraints due to site size or location, and a myriad of other factors. The recommended values assume a “normal” range of factors and do not include extraordinary circumstances.

Fixed and Variable O&M Costs

Combined Cycle Operating Costs

The operating costs consist of three components: fixed O&M, variable O&M, and fuel.

Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are composed of equipment, regulatory filings and other direct costs (ODCs).

Variable O&M is composed of the following components:

- Outage Maintenance – Annual maintenance and overhauls and forced outages.
- Consumables Maintenance
- Water Supply Costs

Simple Cycle Operating Costs

The operating costs consist of two components: fixed O&M and variable O&M.

Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are composed of equipment, regulatory filings, and ODCs. As with the combined cycle fixed costs, staffing costs for simple cycle units, and thus total fixed O&M, were found to vary with plant size. In this case, outage costs were found to vary little with the historic generation. This may be because these costs are driven more by starts than by hours of operation. For this reason, these costs were placed in fixed costs instead. This practice appears to be more consistent with the cost estimates developed by other agencies and analysts.

Variable O&M is composed of the following components:

- Consumables Maintenance
- Water Supply Costs

Table C-27and **Table C-28** summarize the Fixed and Variable O&M Components, respectively.

Table C-27: Fixed O&M

Technology	Average	High	Low
Small Simple Cycle	23.94	42.44	6.68
Conventional Simple Cycle (SC)	17.40	42.44	6.68
Advanced Simple Cycle	16.33	39.82	6.27
Conventional Combined Cycle (CC	8.62	12.62	5.76
Conventional CC W/ Duct Firing	8.30	12.62	5.76
Advanced CC	7.17	10.97	5.01

Source: Energy Commission

Table C-28: Variable O&M

Technology	Average	High	Low
Small Simple Cycle	4.17	9.05	0.88
Conventional Simple Cycle (SC)	4.17	9.05	0.88
Advanced Simple Cycle	3.67	8.05	0.79
Conventional Combined Cycle (CC	3.02	3.84	2.19
Conventional CC W/ Duct Firing	3.02	3.84	2.19
Advanced CC	2.69	3.42	1.95

Source: Energy Commission

Comparing Operating and Maintenance Costs

Table C-29 compares the cost ranges developed for this analysis to similar costs reported by other agencies and analysts around the United States. The average case used here is within the range reported elsewhere when looking at the total O&M costs.

Table C-29: Comparison of O&M Cost Estimates

	Fixed O&M	Variable O&M	Total O&M
	$/KW-yr	$/MWh	$/kW-Yr
Conventional CC			
2008 Midwest ISO Joint Coord. System Plan (1200 MW)	$34.61	$2.15	$46.84
2008 CRS Report for Congress 12-13-2008 (400 MW-conventional)	$20.66	$3.05	$38.04
2008 NPPC 6th Power Plan (305 MW)	$17.18	$3.56	$37.43
2007 UCS RPS analysis (2005) UCS case _ave CEC	$10.58	$4.73	$37.49
2009 CEC Cost of Generation (550 MW)-High Cost	***$12.62***	***$3.84***	***$34.49***
2009 CEC Cost of Generation (550 MW)-Average	***$8.30***	***$3.02***	***$25.50***
2007 EIA Assumptions Annual Energy Outlook	$13.22	$2.18	$25.65
2007 UCS RPS analysis (2005) EIA case	$13.16	$2.14	$25.34
Lazard Study (550 MW)	$5.85	$2.75	$21.51
2008 PJM CONE Studies (600 MW)	$21.20	NA	$21.20
2009 CEC Cost of Generation (500 MW)-Low Cost	***$5.76***	***$2.19***	***$18.26***
Standard CC Confidential submitted 2009 (550 MW)	*$6.12*	*$0.89*	*$11.19*
Advanced CC			
2007 UCS RPS analysis (2005) UCS case	$16.20	$3.26	$34.78
2009 CEC Cost of Generation (800 MW)-High Cost	***$10.97***	***$3.42***	***$30.36***
2007 UCS RPS analysis (2005) EIA case	$12.38	$2.14	$24.55
2008 CRS Report for Congress 12-13-2008 (400 MW Advanced)	$12.11	$2.09	$23.99
2009 CEC Cost of Generation (800 MW) - Average	***$7.17***	***$2.69***	***$22.47***
2009 CEC Cost of Generation (800 MW)-Low Cost	***$5.01***	***$1.95***	***$16.10***
Conventional CT			
2009 CEC Cost of Generation (100 MW)-High Cost	***$42.44***	***$9.05***	***$46.41***
2008 Midwest ISO Joint Coord. System Plan (1200 MW)	$18.03	$3.72	$19.66
2009 CEC Cost of Generation (100 MW)	***$17.40***	***$4.17***	***$19.23***
Standard and Poors April 15, 2009 (cap not listed)	$15.00	$2.50	$16.10
2008 NPPC 6th Power Plan	$15.32	$4.38	$17.24
NYISO NERA LM6000 w/SCR (Central case)	$14.51	$3.50	$16.04
PJM CONE CT GE FA 170 MW (2008)	$14.10	NA	$14.10
RETI (Capacity Value 2007) CEC data	$14.63	NA	$14.63
2007 EIA Assumptions Annual Energy Outlook	$12.83	$3.78	$14.48
2009 CEC Cost of Generation (100 MW)-Low Cost	***$6.68***	***$0.88***	***$7.07***
Advanced CT			
2009 CEC Cost of Generation (200 MW)-High Cost	***$39.82***	***$8.05***	***$46.81***
2009 CEC Cost of Generation (200 MW)-Average	***$16.33***	***$3.56***	***$19.55***
PJM CONE CT 2008 (Siemens Flexplant 10)	$19.03	NA	$19.03
PJM CONE CT 2008 (LMS 100)	$17.40	NA	$17.40
2007 EIA Assumptions Annual Energy Outlook	$11.15	$3.35	$14.09
2007 UCS RPS analysis (2005) EIA case	$11.14	$3.38	$14.10
2007 UCS RPS analysis (2005) UCS case-Ave. CEC	$7.20	$3.04	$9.86
LMS 100 Confidential (Submitted 2009)	$7.00	$2.50	$9.19
2009 CEC Cost of Generation (200 MW)-Low Cost	***$6.27***	***$0.79***	***$6.95***

Note: The high and low values for the 2009 analysis are based on the 5 percentile and 95 percentile values for the evaluated projects.
Source: Energy Commission review of noted documents.

APPENDIX D: Natural Gas Prices

The Model requires natural gas price forecasts for the time frame being modeled. Because natural gas prices were not forecast by the Energy Commission for the *2009 IEPR*, this report uses the natural gas prices based on those developed in the *2007 IEPR* and then adjusted to provide high and low inputs. These are shown in **Table D-1**. In order to convert these into Utility specific gas prices, the gas area prices are generation weighted as shown in **Table D-2.**

Table D-1: Natural Gas Prices by Area (Nominal $/MMBtu)

	California (Nominal$/MMBtu)												
YEAR	NG PG&E BB FG	NG PG&E LT FG	NG SMUD FG <85mmcf/d	NG SMUD FG >85mmcf/d	NG Kern River FG	NG Mojave PL FG	NG SCE Coolwater FG	NG SoCalGas FG	NG Blythe FG	NG SoCal Production FG	NG TEOR Cogen FG	NG SDG&E FG	NG Otay Mesa FG
2009	$6.55	$6.72	$6.49	$6.55	$5.78	$5.78	$6.71	$6.80	$6.35	$6.21	$6.38	$6.35	$6.35
2010	$7.16	$7.33	$7.10	$7.16	$6.24	$6.24	$7.33	$7.06	$6.62	$6.64	$6.83	$6.62	$6.62
2011	$7.38	$7.55	$7.32	$7.38	$6.60	$6.60	$7.55	$7.44	$6.98	$7.02	$7.22	$7.00	$6.99
2012	$8.12	$8.29	$8.06	$8.12	$7.04	$7.04	$8.29	$7.97	$7.48	$7.49	$7.69	$7.50	$7.50
2013	$8.51	$8.68	$8.45	$8.51	$7.44	$7.44	$8.68	$8.38	$7.87	$7.91	$8.13	$7.90	$7.90
2014	$8.96	$9.14	$8.90	$8.96	$7.89	$7.89	$9.14	$8.86	$8.32	$8.38	$8.61	$8.35	$8.35
2015	$9.36	$9.54	$9.29	$9.36	$8.19	$8.19	$9.53	$9.03	$8.46	$8.70	$8.94	$8.46	$8.46
2016	$9.85	$10.03	$9.79	$9.85	$8.97	$8.97	$10.03	$9.78	$9.14	$9.51	$9.77	$9.03	$9.03
2017	$10.48	$10.66	$10.41	$10.48	$9.47	$9.47	$10.66	$10.30	$9.63	$10.04	$10.32	$9.62	$9.61
2018	$11.25	$11.44	$11.18	$11.25	$10.14	$10.14	$11.43	$10.99	$10.27	$10.74	$11.04	$10.26	$10.26
2019	$12.21	$12.41	$12.14	$12.21	$10.94	$10.94	$12.40	$11.82	$11.03	$11.59	$11.91	$11.02	$11.02
2020	$12.64	$12.84	$12.57	$12.64	$11.39	$11.39	$12.83	$12.29	$11.47	$12.03	$12.37	$11.46	$11.46
2021	$13.00	$13.20	$12.93	$13.00	$11.84	$11.84	$13.19	$12.76	$11.92	$12.50	$12.85	$11.90	$11.90
2022	$13.95	$14.15	$13.87	$13.95	$12.81	$12.81	$14.14	$13.76	$12.88	$13.51	$13.89	$12.86	$12.86
2023	$14.50	$14.71	$14.43	$14.50	$13.29	$13.29	$14.70	$14.25	$13.35	$14.01	$14.41	$13.34	$13.34
2024	$15.10	$15.31	$15.02	$15.10	$13.89	$13.89	$15.30	$14.89	$13.96	$14.64	$15.05	$13.95	$13.95
2025	$15.05	$15.26	$14.97	$15.05	$13.84	$13.84	$15.25	$14.84	$13.91	$14.59	$15.00	$13.90	$13.90
2026	$15.65	$15.86	$15.57	$15.65	$14.44	$14.44	$15.85	$15.48	$14.52	$15.21	$15.64	$14.51	$14.51
2027	$16.07	$16.28	$15.99	$16.07	$14.82	$14.82	$16.27	$15.88	$14.88	$15.61	$16.05	$14.88	$14.87
2028	$16.49	$16.70	$16.40	$16.49	$15.21	$15.21	$16.69	$16.29	$15.25	$16.02	$16.47	$15.24	$15.24
2029	$17.13	$17.35	$17.05	$17.13	$15.82	$15.82	$17.34	$16.94	$15.87	$16.65	$17.12	$15.86	$15.86
2030	$17.79	$18.01	$17.71	$17.79	$16.45	$16.45	$18.01	$17.61	$16.50	$17.31	$17.79	$16.50	$16.49

Source: Energy Commission

Table D-2: Natural Gas Prices by Utility (Nominal $/MMBtu)

Trans Area	Fuel Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Annual Average Fuel Price ($/MMBtu)																						
PG&E	NG PG&E BB FG	6.55	7.16	7.38	8.12	8.51	8.96	9.36	9.85	10.48	11.25	12.21	12.64	13.00	13.95	14.50	15.10	15.05	15.65	16.07	16.49	17.13
PG&E	NG PG&E LT FG	6.72	7.33	7.55	8.29	8.68	9.14	9.54	10.03	10.66	11.44	12.41	12.84	13.20	14.15	14.71	15.31	15.26	15.86	16.28	16.70	17.35
PG&E	NG SoCal Production FG	6.21	6.64	7.02	7.49	7.91	8.38	8.70	9.51	10.04	10.74	11.59	12.03	12.50	13.51	14.01	14.64	14.59	15.21	15.61	16.02	16.65
PG&E	NG TEOR Cogen FG	6.38	6.83	7.22	7.69	8.13	8.61	8.94	9.77	10.32	11.04	11.91	12.37	12.85	13.89	14.41	15.05	15.00	15.64	16.05	16.47	17.12
PG&E	NG Kern River FG	5.78	6.24	6.60	7.04	7.44	7.89	8.19	8.97	9.47	10.14	10.94	11.39	11.84	12.81	13.29	13.89	13.84	14.44	14.82	15.21	15.82
PG&E	Weighted Fuel Price	6.44	7.01	7.28	7.92	8.33	8.79	9.15	9.75	10.35	11.09	12.02	12.46	12.85	13.81	14.35	14.95	14.90	15.51	15.92	16.34	16.98
SCE	NG Coolwater	6.71	7.33	7.55	8.29	8.68	9.14	9.53	10.03	10.66	11.43	12.40	12.83	13.19	14.14	14.70	15.30	15.25	15.85	16.27	16.69	17.34
SCE	NG Mojave PL	5.78	6.24	6.60	7.04	7.44	7.89	8.19	8.97	9.47	10.14	10.94	11.39	11.84	12.81	13.29	13.89	13.84	14.44	14.82	15.21	15.82
SCE	NG SCG	6.80	7.06	7.44	7.97	8.38	8.86	9.03	9.78	10.30	10.99	11.82	12.29	12.76	13.76	14.25	14.89	14.84	15.48	15.88	16.29	16.94
SCE	NG TEOR Cogen	6.38	6.83	7.22	7.69	8.13	8.61	8.94	9.77	10.32	11.04	11.91	12.37	12.85	13.89	14.41	15.05	15.00	15.64	16.05	16.47	17.12
SCE	NG Kern River	5.78	6.24	6.60	7.04	7.44	7.89	8.19	8.97	9.47	10.14	10.94	11.39	11.84	12.81	13.29	13.89	13.84	14.44	14.82	15.21	15.82
SCE	Weighted Fuel Price	6.57	6.88	7.26	7.77	8.20	8.66	8.88	9.64	10.08	10.77	11.60	12.06	12.52	13.52	14.02	14.64	14.59	15.22	15.62	16.02	16.66
SDG&E	NG Otay Mesa	6.35	6.62	6.99	7.50	7.90	8.35	8.46	9.03	9.61	10.26	11.02	11.46	11.90	12.86	13.34	13.95	13.90	14.51	14.87	15.24	15.86
SDG&E	NG SDG&E	6.35	6.62	7.00	7.50	7.90	8.35	8.46	9.03	9.62	10.26	11.02	11.46	11.90	12.86	13.34	13.95	13.90	14.51	14.88	15.24	15.86
SDG&E	Weighted Fuel Price	6.35	6.62	7.00	7.50	7.90	8.35	8.46	9.03	9.62	10.26	11.02	11.46	11.90	12.86	13.34	13.95	13.90	14.51	14.88	15.24	15.86
SMUD	NG SMUD FG (<85mmcf/d)	6.49	7.10	7.32	8.06	8.45	8.90	9.29	9.79	10.41	11.18	12.14	12.57	12.93	13.87	14.43	15.02	14.97	15.57	15.99	16.40	17.05
SMUD	NG SMUD FG (>85mmcf/d)	6.55	7.16	7.38	8.12	8.51	8.96	9.36	9.85	10.48	11.25	12.21	12.64	13.00	13.95	14.50	15.10	15.05	15.65	16.07	16.49	17.13
SMUD	Weighted Fuel Price	6.52	7.13	7.35	8.09	8.48	8.93	9.32	9.82	10.44	11.21	12.18	12.61	12.96	13.91	14.46	15.06	15.01	15.61	16.03	16.45	17.09
IID/LADWP	NG SCG	6.80	7.06	7.44	7.97	8.38	8.86	9.03	9.78	10.30	10.99	11.82	12.29	12.76	13.76	14.25	14.89	14.84	15.48	15.88	16.29	16.94
IID/LADWP	Weighted Fuel Price	6.80	7.06	7.44	7.97	8.38	8.86	9.03	9.78	10.30	10.99	11.82	12.29	12.76	13.76	14.25	14.89	14.84	15.48	15.88	16.29	16.94
STATEWIDE AVERAGE PRICE		6.56	6.97	7.29	7.87	8.28	8.74	9.01	9.68	10.20	10.91	11.78	12.23	12.66	13.64	14.16	14.77	14.73	15.35	15.75	16.15	16.80
Trans Area	Fuel Group	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Generation (MWh)																						
PG&E	NG PG&E BB FG	139,221	151,782	156,345	162,703	173,161	178,880	168,916	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817	173,817
PG&E	NG PG&E LT FG	145,222	156,910	147,178	143,131	139,911	140,003	139,363	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221	145,221
PG&E	NG SoCal Production FG	23,771	22,071	22,058	21,793	21,475	22,019	22,122	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142	22,142
PG&E	NG TEOR Cogen FG	46,848	46,839	46,841	46,931	46,767	46,770	46,779	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908	46,908
PG&E	NG Kern River FG	73,577	73,282	72,412	72,303	69,389	69,913	70,634	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389	69,389
PG&E	Total Generation	428,638	450,883	444,834	446,861	450,704	457,585	447,813	457,477	457,477	457,477	457,477	457,477	457,477	457,477	457,477	457,477	457,477	457,477	457,477	457,477	457,477
SCE	NG Coolwater	11,911	10,486	10,777	8,889	6,491	5,802	6,464	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713
SCE	NG Mojave PL	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763	1,763
SCE	NG SCG	268,641	247,060	245,783	244,098	260,724	259,501	263,812	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149	268,149
SCE	NG TEOR Cogen	29,752	29,767	29,742	29,818	29,711	29,714	29,726	29,792	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506	76,506
SCE	NG Kern River	69,807	69,706	68,238	67,903	64,143	65,319	65,469	64,606	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217	134,217
SCE	Total Generation	381,874	358,782	356,304	352,472	362,831	362,100	367,235	371,023	487,349	487,349	487,349	487,349	487,349	487,349	487,349	487,349	487,349	487,349	487,349	487,349	487,349
SDG&E	NG Otay Mesa	22,013	21,100	21,277	21,136	21,026	21,017	21,762	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703	21,703
SDG&E	NG SDG&E	37,195	35,539	46,993	53,164	53,513	54,003	58,088	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912	57,912
SDG&E	Total Generation	59,209	56,639	68,271	74,300	74,539	75,020	79,850	79,615	79,615	79,615	79,615	79,615	79,615	79,615	79,615	79,615	79,615	79,615	79,615	79,615	79,615
SMUD	NG SMUD FG (<85mmcf/d)	20,903	22,265	21,819	21,552	21,154	21,462	29,631	31,182	31,183	31,183	31,184	31,184	31,185	31,185	31,186	31,186	31,187	31,187	31,187	31,187	31,187
SMUD	NG SMUD FG (>85mmcf/d)	20,903	22,265	21,819	21,552	21,154	21,462	29,631	31,182	31,183	31,183	31,184	31,184	31,185	31,185	31,186	31,186	31,187	31,187	31,187	31,187	31,187
SMUD	Total Generation	41,806	44,530	43,638	43,104	42,308	42,924	59,262	62,364	62,365	62,366	62,367	62,368	62,369	62,370	62,371	62,372	62,373	62,373	62,373	62,373	62,373
IID/LADWP	NG SCG	268,641	247,060	245,783	244,098	260,724	259,501	263,812	268,149	268,150	268,151	268,152	268,153	268,154	268,155	268,156	268,157	268,158	268,159	268,160	268,161	268,162
IID/LADWP	Total Generation	268,641	247,060	245,783	244,098	260,724	259,501	263,812	268,149	268,150	268,151	268,152	268,153	268,154	268,155	268,156	268,157	268,158	268,159	268,160	268,161	268,162
STATEWIDE GENERATION		1,180,167	1,157,893	1,158,830	1,160,835	1,191,106	1,197,129	1,217,972	1,238,629	1,354,956	1,354,958	1,354,960	1,354,962	1,354,964	1,354,966	1,354,968	1,354,970	1,354,972	1,354,973	1,354,974	1,354,975	1,354,976

Source: Energy Commission

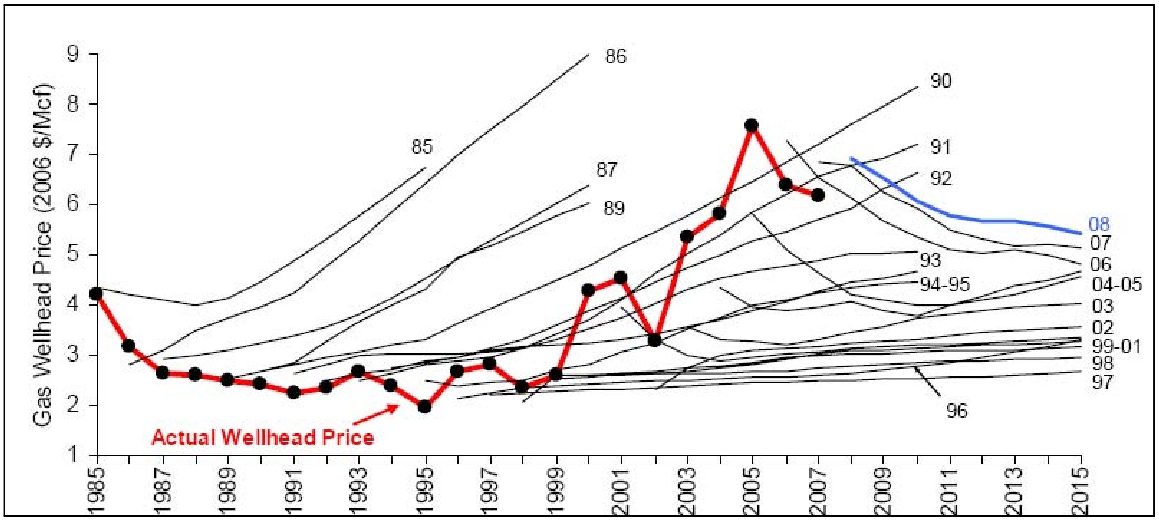
Method for High/Low Values

The outset that the typical high and low natural gas price forecasts are upper limits for each year in the forecast period. Such forecasts are not intended to be interpreted as sustainable over the forecast period. It is expected that in individual years, fuel costs may achieve these limits but that in subsequent years market forces will drive the prices back toward the forecasted average value. The high and low gas prices needed for the Model are different in that they are intended to be average sustainable high and low values to have meaningful levelized cost estimates.

The forecasting of high and low natural gas prices is daunting as it requires an assessment of all the factors that might cause the gas price to deviate from the expected value. There are of course all the unknown future conditions such as changes in demand, temperature deviations, hydro conditions, and economic development. But there are also other factors that might cause the forecaster to miss the mark such as unknown future equipment costs, market power, and poor forecasting. Staff decided to assess these many factors collectively and somewhat indirectly by simply looking backward at the historical limits of forecasting. That is, staff assumes that present forecasts will most likely miss the mark to the degree that previous forecasts failed to predict natural gas prices.

To do this, staff elected to use Energy Information Administration (EIA) natural gas price data that quantifies their forecasting errors. The EIA, like the Energy Commission, has the ability to make forecasts and is therefore a reasonable proxy for an Energy Commission effort. It also provides possibly the most complete historical summary of forecasting errors available. **Figure D-1** shows EIA's historical record of errors in forecasting. It compares EIA's Energy Annual Outlook (EAO) forecasts to actual natural gas prices. The numerical identification is the last two digits of the EAO forecast; for example, "85" signifies the 1985 EAO forecast. It is apparent that in their earlier forecasts, the EIA tended to overestimate natural gas prices. In more recent years, there was a tendency to underestimate natural gas prices. The salient point, however, is that this very competent group of professionals was consistently unable to predict natural gas prices even in the near term. This demonstrates that natural gas price forecasting is a daunting task and that average gas price forecasts are inevitably wrong, making a range of forecasts necessary to recognize the risk involved in relying on these point forecasts.

Figure D-1: Historical EIA Wellhead Natural Gas Price Forecast vs. Actual Price



Source: Berkeley National Lab

Table D-3 shows the corresponding percentage errors for each of these EAO forecasts, as calculated by the EIA. Note that the percentage error in any year can vary from being 721.7 percent too high to being 65.3 percent too low. **Table D-4** shows the same data but rearranged as a function of the number of the forecast year. That is, the first year of each forecast is aligned under the designation "1st"—the second year of each forecast is aligned under the designation "2nd"—and so forth. Forecasts AEO1982–AEO1984 have been deleted since the early years of these forecasts are not provided by EIA, making this data unusable. **Figure D-2** shows this same data graphically. The data initially appears to be meaningless; however, it can be made to be quite useful.

Table D-3: Percentage Errors in EIA Forecasting

Forecast	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
AEO 1982	72.0	182.1	299.6	344.6	375.6	401.0																	
AEO 1983	16.7	60.1	107.4	132.5	169.8	207.4					721.7												
AEO 1984	10.4	49.3	92.3	114.6	144.6	180.1					501.7												
AEO 1985	3.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	150.1	215.4	330.3												
AEO 1986		-10.8	17.1	35.4	50.5	64.4	91.9	114.2	112.9	173.4	280.3	213.0	231.9	339.9	341.8	193.4							
AEO 1987			9.6	15.2	24.6	33.5	51.5	56.6	51.0	89.7	162.9					105.0							
AEO 1989*				-4.1	0.6	11.4	29.9	48.1	49.1	88.1	153.5	119.5	125.3	195.8	193.7	89.7							
AEO 1990					5.3	10.2					89.1					45.8					24.9		
AEO 1991						3.5	15.8	21.3	12.8	30.6	61.7	19.9	17.9	48.5	50.2	1.8	7.8	71.9	18.2	18.1	-0.6	26.5	39.9
AEO 1992							2.8	6.2	-0.4	16.1	51.6	15.7	18.2	53.7	55.1	3.5	5.9	60.5	7.7	5.8	-13.1	7.6	17.4
AEO 1993								6.1	-5.1	13.0	48.5	12.4	12.0	45.2	42.7	-5.8	-3.9	45.9	-1.4	-3.4	-22.5	-5.4	1.1
AEO 1994									-2.8	14.9	46.2	11.0	11.5	39.2	30.4	-19.0	-21.5	13.4	-26.4	-29.5	-42.9	-29.5	-23.1
AEO 1995										2.3	28.9	-10.0	-11.0	9.8	9.6	-30.2	-27.6	7.1	-27.1	-29.1	-41.8	-28.7	-24.1
AEO 1996											5.2	-19.8	-19.7	1.6	-3.9	-40.4	-42.8	-19.4	-49.3	-52.6	-62.9	-55.7	-53.6
AEO 1997												-6.3	-21.4	-2.8	-9.2	-43.9	-46.6	-25.0	-52.5	-55.5	-65.3	-58.5	-56.7
AEO 1998													-1.0	12.1	3.0	-37.2	-40.5	-17.1	-48.4	-52.5	-63.3	-56.3	-54.2
AEO 1999														0.9	-1.9	-40.1	-42.1	-17.8	-48.1	-51.8	-62.4	-54.6	-52.8
AEO 2000															-2.0	-39.3	-43.3	-21.4	-50.9	-54.0	-63.7	-56.0	-53.5
AEO 2001																-7.8	-12.9	0.8	-43.9	-50.5	-61.4	-53.9	-52.1
AEO 2002																	0.6	-30.1	-48.1	-47.9	-59.0	-51.1	-49.4
AEO 2003																		-5.6	-33.2	-42.8	-57.1	-50.8	-48.3
AEO 2004																			1.9	-26.8	-49.3	-41.8	-39.6
AEO 2005																				-1.4	-24.7	-22.7	-28.5
AEO 2006																					6.5	11.9	2.2
AEO 2007																						7.3	9.6
AEO 2008																							-0.3
Average	25.7	63.0	97.5	99.7	105.7	111.9	54.5	58.4	46.0	71.5	190.9	39.5	36.4	67.6	59.1	11.7	-22.2	4.9	-28.7	-31.6	-38.7	-30.1	-25.9
High	72.0	182.1	299.6	344.6	375.6	401.0	135.0	156.3	150.1	215.4	**721.7**	213.0	231.9	339.9	341.8	193.4	7.8	71.9	18.2	18.1	24.9	26.5	39.9
Low	3.6	-10.8	9.6	-4.1	0.6	3.5	2.8	6.1	-5.1	2.3	5.2	-19.8	-21.4	-2.8	-9.2	-43.9	-46.6	-30.1	-52.5	-55.5	**-65.3**	-58.5	-56.7

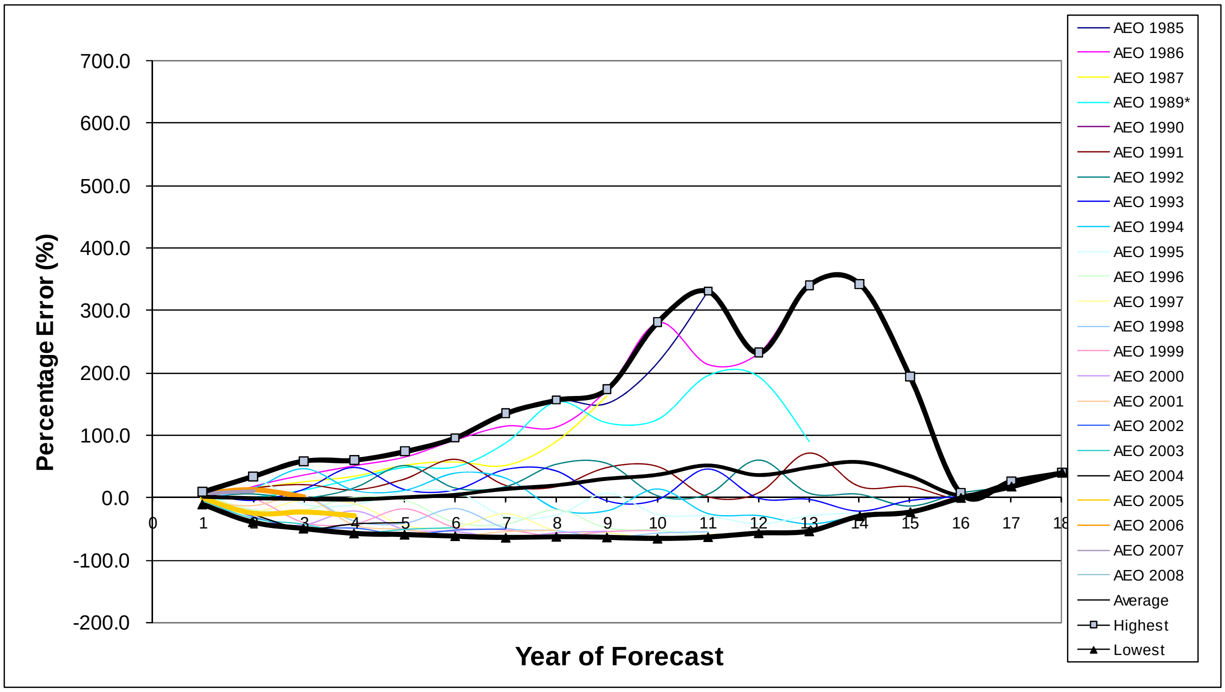
Source: EIA

Table D-4: Percentage Errors in the Year of Forecast

Forecast	1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11th	12th	13th	14th	15th	16th	17th	18th
AEO 1985	3.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	150.1	215.4	330.3							
AEO 1986	-10.8	17.1	35.4	50.5	64.4	91.9	114.2	112.9	173.4	280.3	213.0	231.9	339.9	341.8	193.4			
AEO 1987	9.6	15.2	24.6	33.5	51.5	56.6	51.0	89.7	162.9					105.0				
AEO 1989*	-4.1	0.6	11.4	29.9	48.1	49.1	88.1	153.5	119.5	125.3	195.8	193.7	89.7					
AEO 1990	5.3	10.2					89.1					45.8					24.9	
AEO 1991	3.5	15.8	21.3	12.8	30.6	61.7	19.9	17.9	48.5	50.2	1.8	7.8	71.9	18.2	18.1	-0.6	26.5	39.9
AEO 1992	2.8	6.2	-0.4	16.1	51.6	15.7	18.2	53.7	55.1	3.5	5.9	60.5	7.7	5.8	-13.1	7.6	17.4	
AEO 1993	6.1	-5.1	13.0	48.5	12.4	12.0	45.2	42.7	-5.8	-3.9	45.9	-1.4	-3.4	-22.5	-5.4	1.1		
AEO 1994	-2.8	14.9	46.2	11.0	11.5	39.2	30.4	-19.0	-21.5	13.4	-26.4	-29.5	-42.9	-29.5	-23.1			
AEO 1995	2.3	28.9	-10.0	-11.0	9.8	9.6	-30.2	-27.6	7.1	-27.1	-29.1	-41.8	-28.7	-24.1				
AEO 1996	5.2	-19.8	-19.7	1.6	-3.9	-40.4	-42.8	-19.4	-49.3	-52.6	-62.9	-55.7	-53.6					
AEO 1997	-6.3	-21.4	-2.8	-9.2	-43.9	-46.6	-25.0	-52.5	-55.5	-65.3	-58.5	-56.7						
AEO 1998	-1.0	12.1	3.0	-37.2	-40.5	-17.1	-48.4	-52.5	-63.3	-56.3	-54.2							
AEO 1999	0.9	-1.9	-40.1	-42.1	-17.8	-48.1	-51.8	-62.4	-54.6	-52.8								
AEO 2000	-2.0	-39.3	-43.3	-21.4	-50.9	-54.0	-63.7	-56.0	-53.5									
AEO 2001	-7.8	-12.9	0.8	-43.9	-50.5	-61.4	-53.9	-52.1										
AEO 2002	0.6	-30.1	-48.1	-47.9	-59.0	-51.1	-49.4											
AEO 2003	-5.6	-33.2	-42.8	-57.1	-50.8	-48.3												
AEO 2004	1.9	-26.8	-49.3	-41.8	-39.6													
AEO 2005	-1.4	-24.7	-22.7	-28.5														
AEO 2006	6.5	11.9	2.2															
AEO 2007	7.3	9.6																
AEO 2008	-0.3																	
Average	0.6	-1.8	-3.1	-4.0	-0.2	3.8	13.3	19.0	29.5	35.8	51.0	35.5	47.6	56.4	34.0	2.7	22.9	39.9
Highest	9.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	173.4	280.3	330.3	231.9	339.9	341.8	193.4	7.6	26.5	39.9
Lowest	-10.8	-39.3	-49.3	-57.1	-59.0	-61.4	-63.7	-62.4	-63.3	-65.3	-62.9	-56.7	-53.6	-29.5	-23.1	-0.6	17.4	39.9

Source: Energy Commission

Figure D-2: Percentage Errors in the Year of Forecast



Source: Energy Commission

Table D-5 and **Table D-6** show this same data but with the overestimates and the underestimates tabulated separately. **Figure D-3** and **Figure D-4** show the summary portion graphically at the bottom of the respective tables.

Table D-5: Percentage Errors in Overestimates

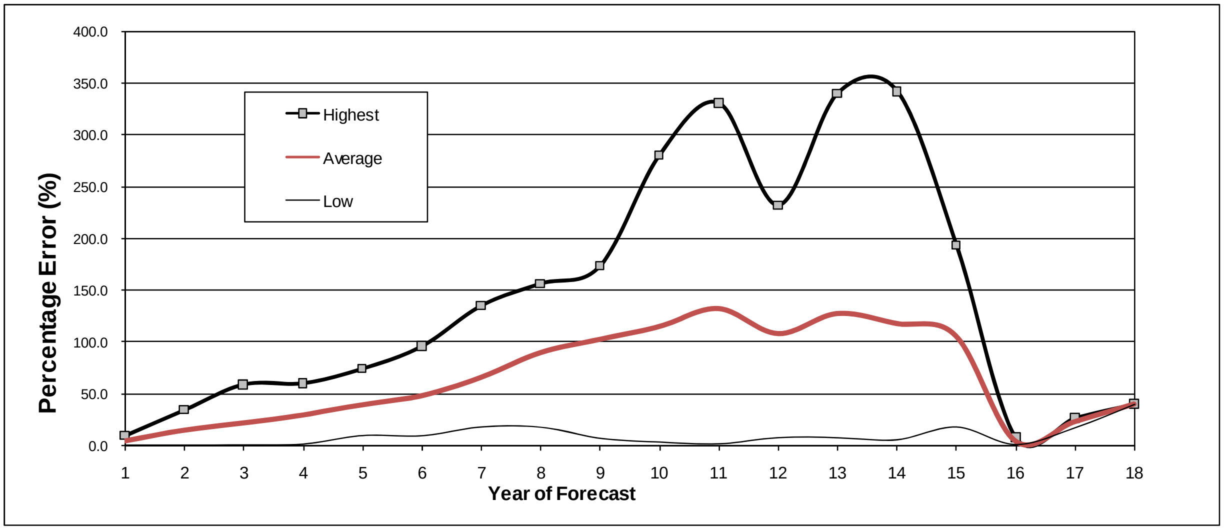
Forecast	1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11th	12th	13th	14th	15th	16th	17th	18th
AEO 1985	3.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	150.1	215.4	330.3							
AEO 1986		17.1	35.4	50.5	64.4	91.9	114.2	112.9	173.4	280.3	213.0	231.9	339.9	341.8	193.4			
AEO 1987	9.6	15.2	24.6	33.5	51.5	56.6	51.0	89.7	162.9					105.0				
AEO 1989*		0.6	11.4	29.9	48.1	49.1	88.1	153.5	119.5	125.3	195.8	193.7	89.7					
AEO 1990	5.3	10.2					89.1					45.8					24.9	
AEO 1991	3.5	15.8	21.3	12.8	30.6	61.7	19.9	17.9	48.5	50.2	1.8	7.8	71.9	18.2	18.1		26.5	39.9
AEO 1992	2.8	6.2		16.1	51.6	15.7	18.2	53.7	55.1	3.5	5.9	60.5	7.7	5.8		7.6	17.4	
AEO 1993	6.1		13.0	48.5	12.4	12.0	45.2	42.7			45.9					1.1		
AEO 1994		14.9	46.2	11.0	11.5	39.2	30.4			13.4								
AEO 1995	2.3	28.9			9.8	9.6			7.1									
AEO 1996	5.2			1.6														
AEO 1997																		
AEO 1998		12.1	3.0															
AEO 1999	0.9																	
AEO 2000																		
AEO 2001			0.8															
AEO 2002	0.6																	
AEO 2003																		
AEO 2004	1.9																	
AEO 2005																		
AEO 2006	6.5	11.9	2.2															
AEO 2007	7.3	9.6																
AEO 2008																		
Average	4.3	14.7	21.7	29.3	39.3	47.9	65.7	89.5	102.4	114.7	132.1	108.0	127.3	117.7	105.7	4.4	22.9	39.9
Highest	9.6	34.4	59.0	60.2	74.2	95.9	135.0	156.3	173.4	280.3	330.3	231.9	339.9	341.8	193.4	7.6	26.5	39.9
Low	0.6	0.6	0.8	1.6	9.8	9.6	18.2	17.9	7.1	3.5	1.8	7.8	7.7	5.8	18.1	1.1	17.4	39.9

Source: Energy Commission

Table D-6: Percentage Errors in Underestimates

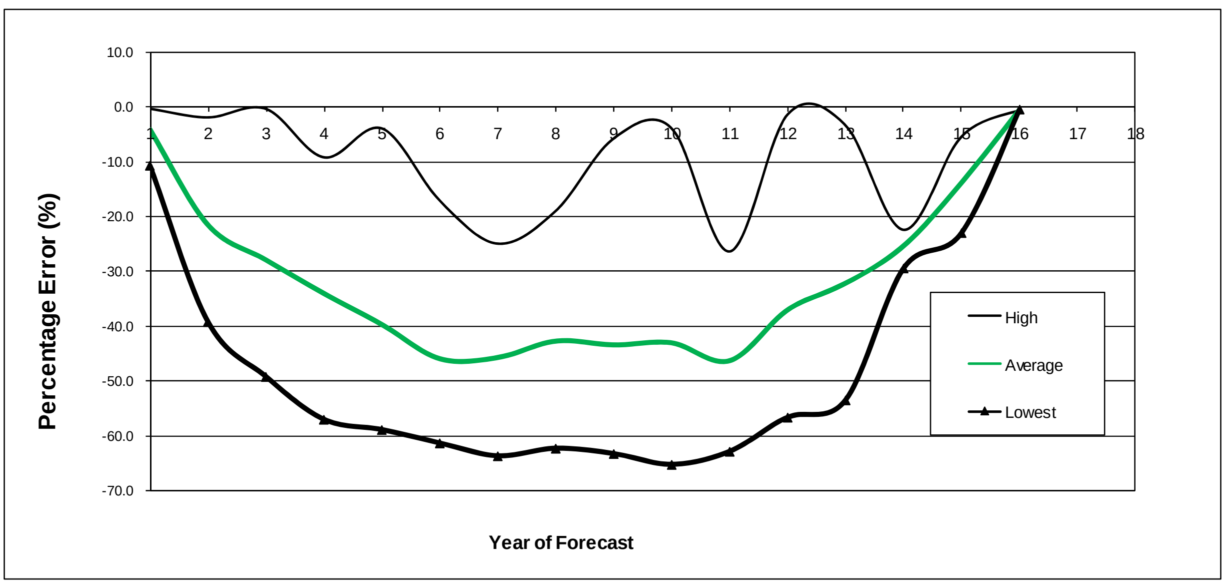
Source: Energy Commission

Figure D-3: Percentage Error in Overestimates



Source: Energy Commission

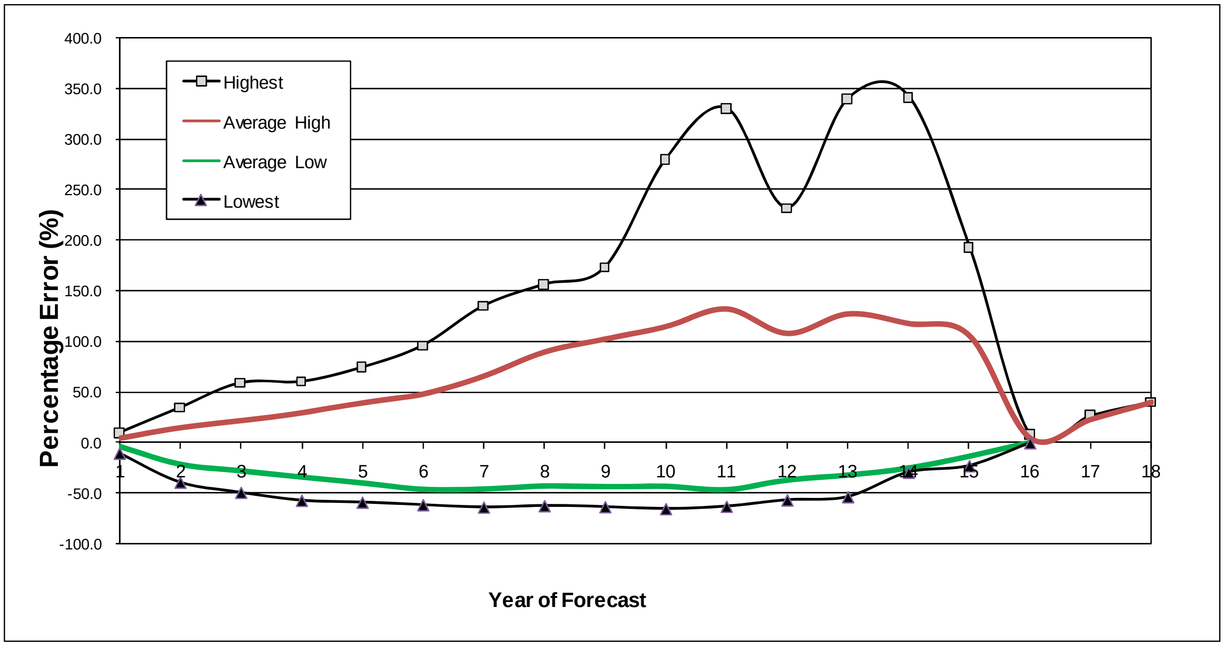
Figure D-4: Percentage Error in Underestimates



Source: Energy Commission

Figure D-5 combines the values above that are of interest: the highest and lowest errors recorded plus the average high and the average low. **Figure D-5** displays the upper and lower limits of the errors plus average high and low errors.

Figure D-5: Average Overestimates and Underestimates

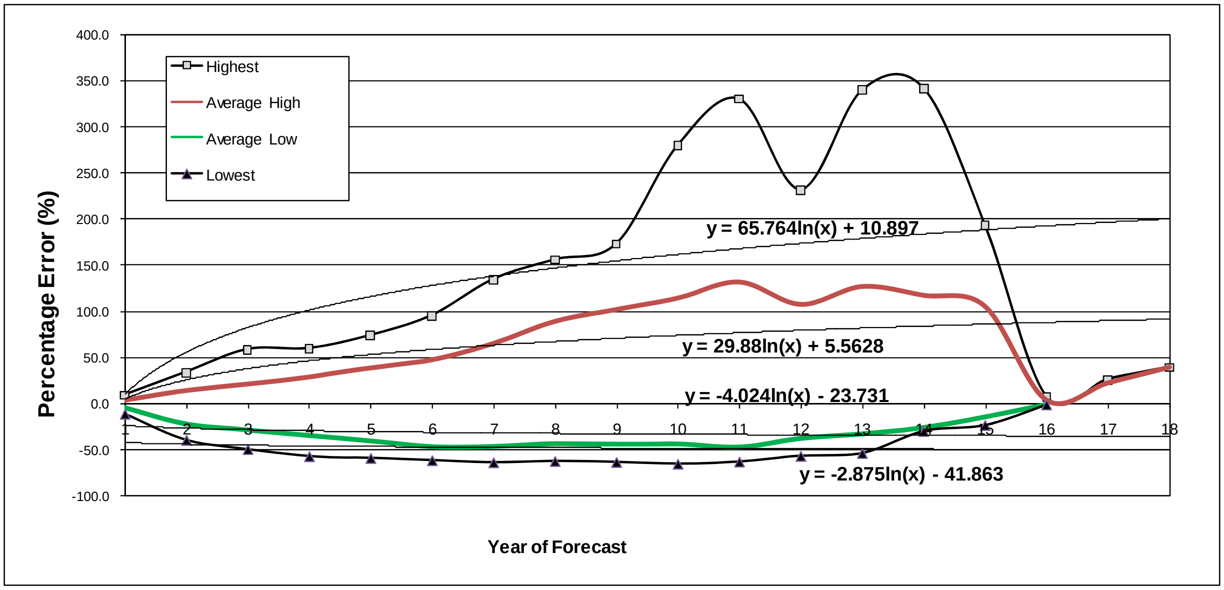


Source: Energy Commission

However, the shapes of these curves are not directly useful for forecasting as they are so irregular and random. The expectation may be that on average the errors would more smoothly increase over the years, and tend to level off in the later years. To convert these unlikely shapes into more average shapes that capture the trend of the errors, logarithmic trendlines were developed for each of these curves, as shown in **Figure D-6.**

Table D-7 summarizes these trendline forecasting errors in the first four columns. The next four columns show the resulting scaling factors calculated from these trendline forecast errors. The last five columns use the final *2007 IEPR* natural gas prices as the Model natural gas prices and the high-low gas prices based on these scaling factors. The scaling factors are shifted two years to account for the fact that the *2007 IEPR* prices are now two years old. **Figure D-7** shows these same prices in a graph. As a reasonableness test, **Figure D-8** compares the Model natural gas prices to some other recent natural gas prices. Two of these forecasts are very close to the calculated high average, probably because their forecast still reflects the early natural gas prices that extended into the early part of the year but have been proven to be inaccurate for 2009.

Figure D-6: Trendlines for Average Overestimates and Underestimates



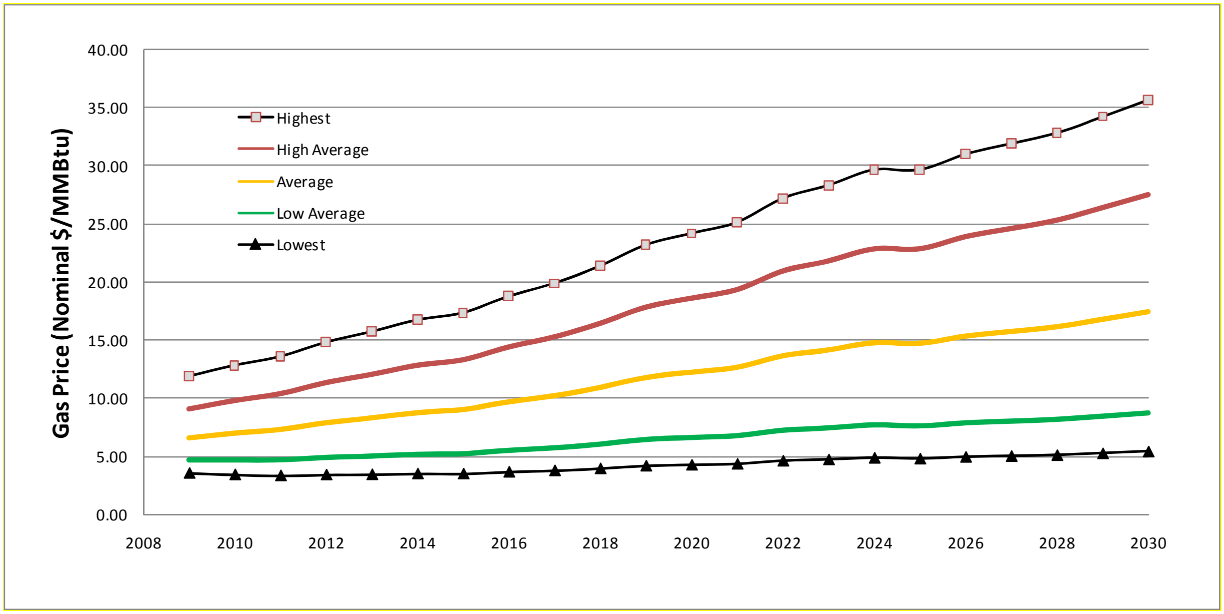
Source: Energy Commission

Table D-7: Trendlines for Average Overestimates and Underestimates

Year of Forecast	Forecast Errors (%)				Forecast Factors				2009 Preliminary Gas Prices (Nominal $/MMBtu)					
	Highest	High Average	Low Average	Lowest	Highest	High Average	Low Average	Lowest	Year	Highest	High Average	Average	Low Average	Lowest
3	83.1	38.4	-28.2	-45.0	1.82	1.39	0.72	0.55	2009	11.94	9.13	6.56	4.74	3.58
4	102.1	47.0	-29.3	-45.8	1.85	1.41	0.68	0.49	2010	12.87	9.86	6.97	4.74	3.45
5	116.7	53.7	-30.2	-46.5	1.87	1.43	0.65	0.46	2011	13.63	10.45	7.29	4.75	3.36
6	128.7	59.1	-30.9	-47.0	1.89	1.45	0.63	0.44	2012	14.85	11.39	7.87	4.95	3.44
7	138.9	63.7	-31.6	-47.5	1.90	1.46	0.61	0.42	2013	15.76	12.10	8.28	5.06	3.47
8	147.6	67.7	-32.1	-47.8	1.92	1.47	0.60	0.40	2014	16.76	12.88	8.74	5.21	3.53
9	155.4	71.2	-32.6	-48.2	1.93	1.48	0.58	0.39	2015	17.38	13.36	9.01	5.26	3.53
10	162.3	74.4	-33.0	-48.5	1.94	1.49	0.57	0.38	2016	18.79	14.44	9.68	5.55	3.69
11	168.6	77.2	-33.4	-48.8	1.95	1.50	0.56	0.37	2017	19.91	15.32	10.20	5.76	3.80
12	174.3	79.8	-33.7	-49.0	1.96	1.51	0.56	0.36	2018	21.40	16.47	10.91	6.07	3.98
13	179.6	82.2	-34.1	-49.2	1.97	1.52	0.55	0.36	2019	23.20	17.86	11.78	6.46	4.21
14	184.5	84.4	-34.4	-49.5	1.98	1.52	0.54	0.35	2020	24.19	18.63	12.23	6.63	4.30
15	189.0	86.5	-34.6	-49.6	1.99	1.53	0.54	0.35	2021	25.15	19.37	12.66	6.79	4.38
16	193.2	88.4	-34.9	-49.8	1.99	1.54	0.53	0.34	2022	27.20	20.95	13.64	7.24	4.65
17	197.2	90.2	-35.1	-50.0	2.00	1.54	0.53	0.34	2023	28.32	21.82	14.16	7.44	4.76
18	201.0	91.9	-35.4	-50.2	2.01	1.55	0.52	0.33	2024	29.65	22.86	14.77	7.70	4.91
19	204.5	93.5	-35.6	-50.3	2.01	1.55	0.52	0.33	2025	29.65	22.86	14.73	7.61	4.84
20	207.9	95.1	-35.8	-50.5	2.02	1.56	0.51	0.32	2026	30.99	23.90	15.35	7.87	4.98
21	211.1	96.5	-36.0	-50.6	2.02	1.56	0.51	0.32	2027	31.89	24.60	15.75	8.01	5.06
22	214.2	97.9	-36.2	-50.7	2.03	1.57	0.51	0.32	2028	32.80	25.31	16.15	8.16	5.14
23	217.1	99.3	-36.3	-50.9	2.04	1.57	0.50	0.32	2029	34.19	26.39	16.80	8.43	5.30
24	219.9	100.5	-36.5	-51.0	2.04	1.58	0.50	0.31	2030	35.63	27.50	17.46	8.71	5.46

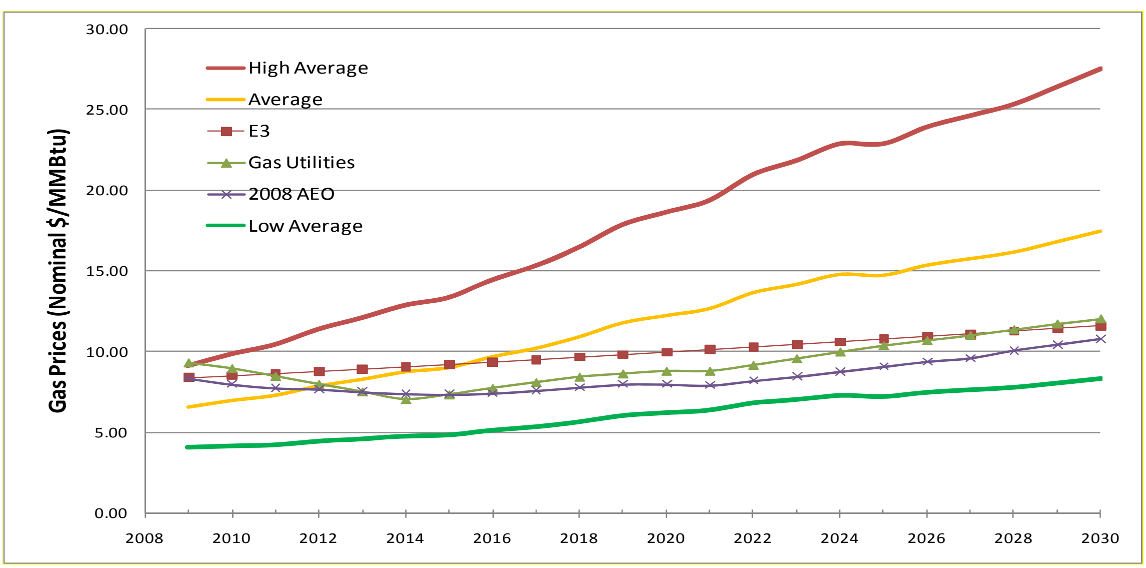
Source: Energy Commission

Figure D-7: Model Input Natural Gas Prices



Source: Energy Commission

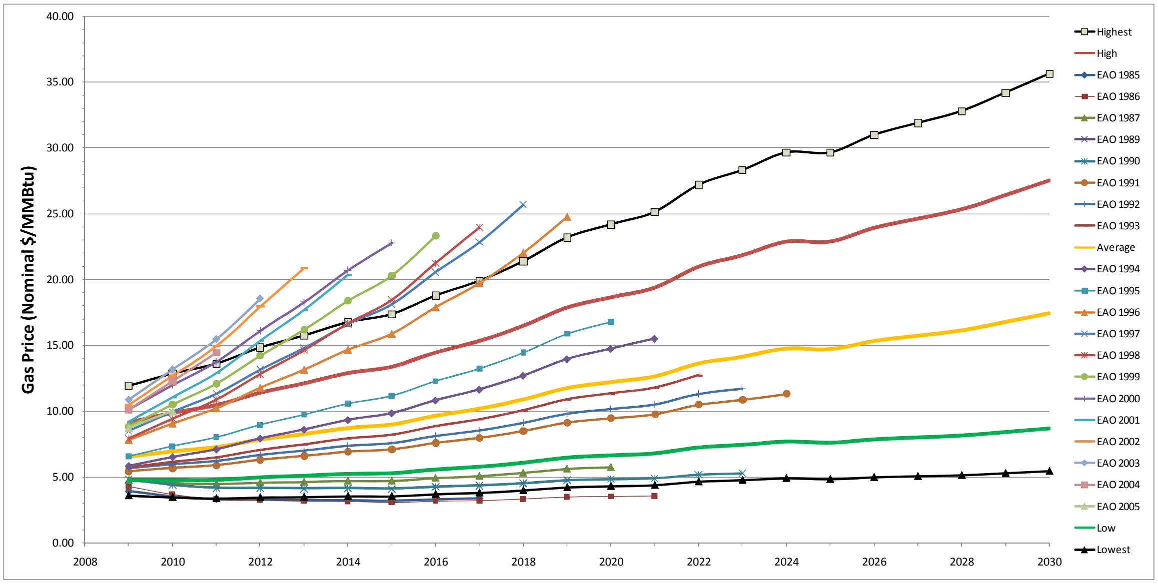
Figure D-8: Model Input Natural Gas Prices Compared With Other Gas Price Forecasts



Source: Energy Commission

Is it realistic to expect that the forecasted errors are sustainable to the extent proposed here? **Figure D-9** addresses this concern. It shows trendline natural gas prices constructed similar to those described above for all of the yearly EIA forecast errors, with Energy Commission trendline forecasts superimposed.

Figure D-9: Natural Gas Prices for All EIA Forecasts vs. Model Input Prices



Source: Energy Commission

It is not easy to compare Energy Commission forecasts to the EIA forecasts since the EIA forecasts are for a limited number of years. It is impossible to say if these forecasts would continue this same trend beyond the forecast period to 2030. However, the data suggests that Energy Commission forecasts fit within the EIA data.

APPENDIX E: Transmission Parameters

Transmission parameters include losses and costs. These are separated into two general categories because of a key difference in a characteristic between conventional and renewable resources. The former are able to be located near load centers and along existing transmission corridors because the fuel can be brought to the power plant. The latter must be located at the energy source, which typically is located far from load centers or transmission corridors. Losses increase with distance, and costs increase with the length of the line. In addition, such lines are most often trunk lines that do not provide other network benefits for interchange among load centers.

It is important to note that there is difference between "costs" and "rates." In this case, the incremental costs of adding transmission to deliver new power can be readily identified by comparing the costs of meeting loads with one set of resources versus another set. However, rates can reflect policy decisions about how to allocate those costs. Those policies can take into account a number of factors that extend beyond the typical economic efficiency criterion. This analysis focuses solely on using the efficiency criterion because incorporating those other factors requires a more extensive system-wide analysis. On the other hand, excluding or ignoring these costs implicitly assumes that these costs are zero.[15]

Transmission Losses

Transmission losses represent the power lost from the point of first interconnection to the point of delivery to the load-serving entity in the California ISO control area. This point of delivery is considered to be the substation at the demarcation between the transmission and distribution system. Losses through the distribution system are not included, so these would have to be added to make these resources comparable to distributed generation (DG) and demand-side management (DSM).

Renewable Generation Losses

For renewables, the losses for California resources are assumed to be 5 percent based on the Renewable Energy Transmission Initiatives *Phase 1B Report*.

[15] As is often the case in many analyses, attempting to ignore the consequences of a particular aspect is identical to making an invalid assumption that the parameter equals zero. In all of these cases, it is necessary to make some type of assumption, even if it cannot be validated with rigorous support.

Conventional Generation Losses

Conventional technologies include gas-fired, coal-fired, and nuclear. These technologies are presumed to be located near load centers, transmission interconnections and fuel transport lines. These losses are estimated based on an average computed for the California ISO control area. California ISO assigns loss factor to locational marginal pricing, assuming local capacity requirements (LCR) losses are appropriate) and then adding in intertie losses. The resulting local area losses from California ISO *2009 Local Capacity Technical Analysis Final Report and Study Results* sub-area transmission losses, based on the equation:

Losses (MW)/Total Load (MW)

- Stockton: 27/1436 = 1.88%
- Sierra Area: 107/2126 = 5%
- Greater Bay Area: 253/10,244 = 2.46 %
- Big Creek Ventura: 143/4734 = 3%
- Humboldt: 9/200 = 4.5 %
- LA Basin: 202/19612 = 1%
- Greater Fresno: 124/3381 = 3.67%
- Kern: 16/1316 = 1.22%
- San Diego: 126/5052 = 2.45%

The weighted average losses for all areas are shown in **Table E-1**.

Table E-1: Average Transmission Losses for Conventional Generation

Load Area	Losses %	Load (MW)
Stockton	1.88%	1436
Sierra Area	5.00%	2126
Greater Bay Area	2.46%	10244
Big Creek Ventura	3.00%	4734
Humbolt	4.50%	200
LA Basin	1.00%	19612
Greater Fresno	3.67%	3381
Kern	1.22%	1316
San Diego	2.45%	5052
Weighted Average =	**2.07%**	

Source: California Independent System Operator, *2009 Local Capacity Technical Analysis Final Report and Study Results.*

Transmission Costs

Transmission costs are composed of two components. The first is the California ISO transmission access charge for all generators. The second is the project-specific cost incurred for trunk lines constructed to interconnect a resource energy zone (REZ) to the control area network.

Transmission Access Charge

The following quote is taken from a March 31, 2009, California ISO filing on transmission access charges:

> "The transmission Access Charges provided in the present filing revise the Access Charges and Wheeling Access Charges provided for informational purposes in the CAISO's submission of March 6, 2009 in Docket No. ER09-824 (deemed by the Commission as filed on March 9, 2009). The changes in the present filing are effective March 1, 2009, in accordance with CAISO Tariff Appendix F, Schedule 3, Section 8. Worksheets illustrating the recalculation of the CAISO's transmission Access Charges are included with the present transmittal letter as Attachment A. The recalculated rates for each of the TAC Areas, effective March 1, 2009, are as follows:
>
> - Northern Area- $4.2727/MWh
> - East/Central Area $4.3512/MWh
> - Southern Area $4.3219/MWh

Based on this filing, an average rate of $4.30 per MWH was included in the costs for all generation technologies.

Transmission Interconnection Costs

In the *2007 IEPR* Scenario Analysis, the Energy Commission estimated the cost of adding sufficient transmission to meet a high renewable generation level relying on in-state resources. This was Scenario 4A. The weighted average costs for REZs identified in that scenario were calculated, as shown in **Table E-2**. These averages include additions in REZs in which no additional transmission capacity is presumed to be required, for example, Tehachapi. These interconnection costs are then added as a separate component in the Model, and then allocated on a per-MWh basis assuming IOU financing under FERC regulation.

Table E-2: Transmission Interconnection Costs per *2007 IEPR* Scenario 4A

Resource Type	Transmission Area[1]	Installed Capacity (MW)	Transmission Costs ($MM)	$/kW
Geothermal	IID	1,526		
	SCE	264		
	PG&E	625		
	Total	**2,415**	**$613**	**$254**
Solar (CSP)	IID	450		
	Imperial Valley	500		
	SDG&E	100		
	SCE	1,350		
	LADWP	0		
	PG&E	300		
	Total	**2,700**	**$374**	**$138**
Wind	IID	0		
	Imperial Valley	600		
	SDG&E	500		
	SCE	6,702		
	LADWP	200		
	PG&E	2,136		
	Total	**10,138**	**$749**	**$74**
Wood/Wood Waste	IID	40		
	SDG&E	219		
	SCE	235		
	PG&E	497		
	Total	**991**	**$39**	**$39**

Source: California Energy Commission, *2007 Integrated Energy Policy Report*.

APPENDIX F: Revenue Requirement and Cash Flow

This appendix describes the Revenue Requirement and Cash-Flow financial accounting used in the COG Model. It describes the modeling algorithms, the development of these algorithms and their respective effects on levelized costs.

Revenue Requirement accounting was used exclusively in the *2007 IEPR*. Although staff was aware that this accounting technique was only truly applicable to IOU and POU developers, and that Cash-Flow accounting was more applicable to merchant developers, initial studies indicated that the differences were small. In the interest of keeping the modeling as simple as reasonably possible, Revenue Requirements was used for all three categories of developers. Studies subsequent to the *2007 IEPR* disclosed that the differences are only small where there are no significant tax benefits: accelerated depreciation, tax credits and Ad Valorem (property tax) exemptions for solar plants. These studies disclosed that Revenue Requirements could overstate the levelized cost for renewable technologies by as much as 30 percent, depending on the applicable tax benefits – keeping in mind that these tax benefits do change over time. Accordingly, for the *2009 IEPR* staff has changed the merchant accounting to reflect cash-flow accounting for Merchant plants.

Algorithms

The complexity of the COG modeling algorithms comes from the need to quantify the revenue, which cannot be known for the generalized case because there is no specified revenue. It is therefore logically set to an amount that is just adequate to meet all expenses. This leads to the dilemma that the revenue cannot be known until the state and federal taxes are calculated, but the state and federal taxes cannot be calculated before the revenue is known—thus the need for simultaneous equations. **Table F-1** illustrates the applicable accounting elements for a binary geothermal unit, which are applicable for both Revenue Requirement and the Cash-Flow accounting – except POUs have neither taxes nor equity payments to account for. Actual values are shown to illustrate the components but are not necessary to the development of the algorithms.

The first row shows the revenue required, which is by our definition equals the levelized cost. It is the sum of all costs: operating expenses; capital cost and financing cost; and state and federal taxes. The before tax income, which is the revenue left after accounting for the operating expenses, must pay the taxes and the capital cost and financing costs (equity and debt). The remaining revenue after paying taxes must pay for debt and return on and of equity which is defined as after tax income. Therefore, Revenue is equal to operating expenses plus before tax income.

Table F-1: Comparison of Revenue Requirement to Cash-Flow

Geothermal - Binary	**Revenue Requirement ($/MWh)**	**Cash-Flow ($/MWh)**
Revenue Requirement *(R)*	$104.29	$83.11
Minus Operating Expenses (O&M, Fuel, Insurance and Ad Valorem) *(OE)*	$47.28	$47.28
Equals Before Tax Income *(BTI)*	$57.01	$35.82
Minus Taxes *(T_f+T_s)*	($44.98)	($48.94)
Equals Debt and Equity Payments *(ATI)*	$102.00	$84.76
Debt Payment	$50.96	$50.96
Equity Payments	$51.04	$32.81
Total Debt and Equity Payments *(ATI)*	$102.00	$84.76

Source: California Energy Commission

- Revenue (*R*) must equal the sum of:
  - Operating Expenses (O*E*):
    - Fixed O&M Costs
    - Insurance & Ad Valorem (Property Taxes)
    - Fuel Cost
    - Variable O&M
  - Before Tax Income[16] (*BTI*):
    - State (T_s) and Federal (T_f) Taxes
    - After Tax Income (*ATI*) is equal to the debt and equity payments

$$R = OE + BTI = OE + ATI + T_f + T_s$$

- 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 Taxes (T_s) –Tax Deduction for Manufacturing Activities (TDMA) – Geothermal Depletion Allowance (GDA)[17]
  - State Deductions (D_s): State Depreciation and Interest on Loan

---

[16] Before Tax Income (BTI) is also called Operating Income or Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA)

[17] GDA is ignored in the model as developers cannot use both GDA & REPTC. Using REPTC is more advantageous as default.

- Federal Deductions (Ds): Federal Depreciation, Interest on Loan, Manufacturing Activities (TDMA), and Geothermal Depletion Allowance (GDA)
- Federal Tax Credits (C_f): BETC, REPTC & REPI

- Taxes are equal to respective Tax Rates (t_f, t_s) times Taxable Income – Tax Credits (C)
  - Federal Taxes: $T_f = t_f(BTI - D_f - T_s) - C_f = t_f(ATI + T_f - D_f) - C_f$

    Solving for T_f: $T_f = \dfrac{t_f(ATI - D_f) - C_f}{(1 - t_f)}$
  - State Taxes: $T_s = t_s(BTI - D_s) - C = t_s(ATI + T_f + T_s - D_s) - C_s$

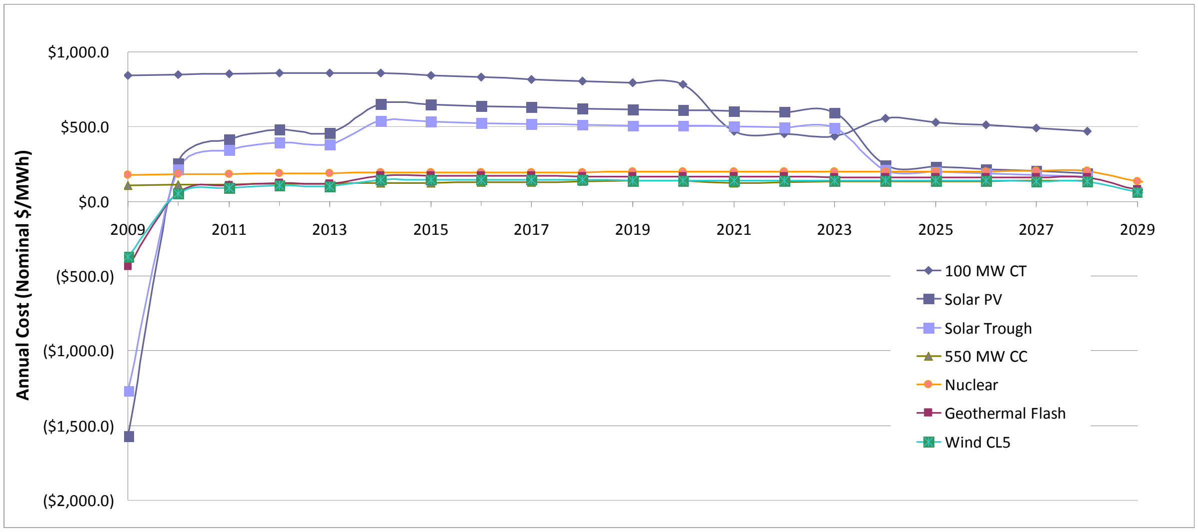
    Solving for T_s: $T_s = \dfrac{t_s(ATI + T_f - D_s) - C_s}{(1 - t_s)}$

These formulas are applicable to both Revenue Requirement and Cash-Flow accounting. The difference 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)

Revenue Requirement

In the Revenue Requirement Income Sheet, the equity return payments are calculated as a percent of the depreciated value of the technology for each year—there is no linkage among years, unlike the cash-flow analysis. Since investment and depreciated value is known a priori, calculating the before-tax net revenue and equity return is straightforward, and taxes are simply a percentage of that income. This results in revenue payments as shown in **Figure F-2**.

Figure F-2: Annual Revenue Stream for Revenue Requirement Accounting

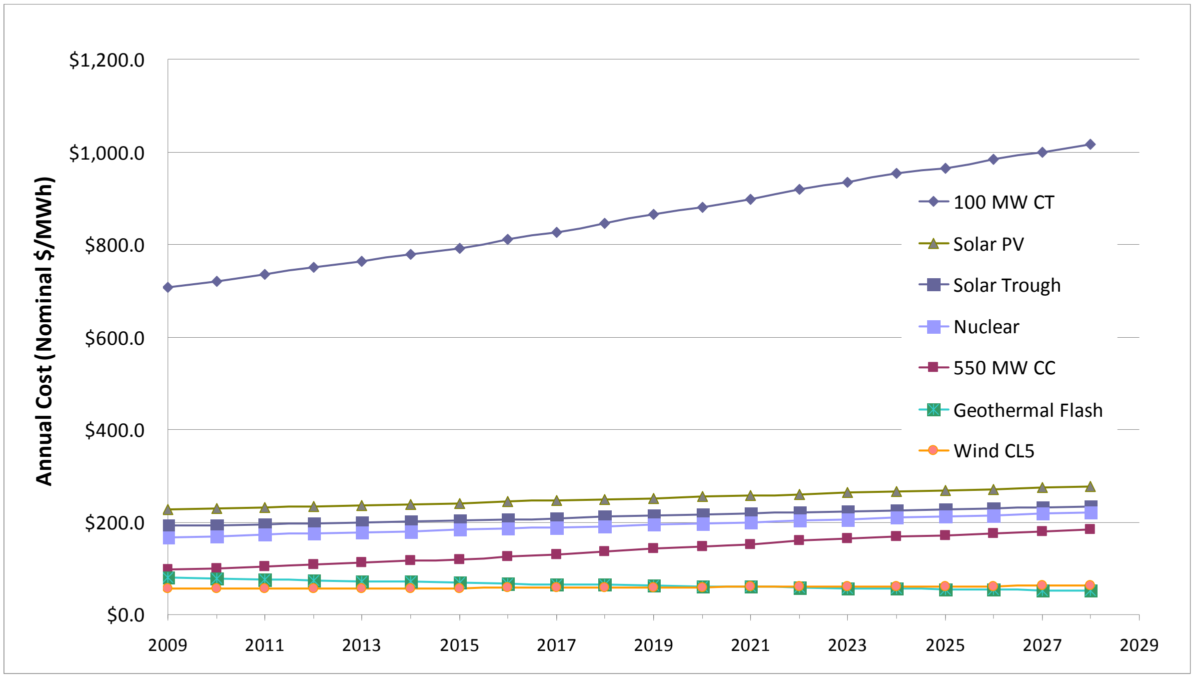


Source: California Energy Commission

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 just 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 so as 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 one year is not independent of the return in other years. The corresponding annual payments are shown in **Figure F-3**.

Figure F-3: Annual Revenue Stream for Cash-Flow Accounting



Source: California Energy Commission

The SCE/E3 COG Model used in the CPUC MPR 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) COG Model used for the RETI studies used the Excel Table function the making 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 COG 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, the authors 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 COG model compared to the B&V RETI model. Instead a piecewise linear function was created using the Table function to capture the nonlinear relationship.[18]

For two reasons, the revenue requirements and cash flow may not necessarily 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 does not affect the revenue requirement within an individual year. The annual revenue requirement is simply a

[18] The Table function calculation can be found on the Income_Cash Flow worksheet in the model, starting at cell B167.

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 different 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 stream 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 in an endogenous fashion. Typically the difference between the cash flow and revenue requirement results is not large, but it typically becomes significant where large tax incentives are applicable to a technology.

APPENDIX G: Contact Personnel

The following is a list of the Energy Commission and contractor personnel who participated in the development of the Model, the data gathering process and the computer simulations, along with their phone numbers and e-mail addresses. This list is intended to facilitate information requests related to this report. If you are in doubt as to whom to contact, you can contact the author, who will direct you to the appropriate source.

SUBJECT	PERSONNEL	PHONE	EMAIL
ENERGY COMMISSION			
Office Manager (EAO)	Ivin Rhyne	(916) 654-4838	irhyne@energy.state.ca.us
Systems Analysis Unit Lead	Al Alvarado	(916) 654-4749	aalvarad@energy.state.ca.us
Project Manager/Author	Joel B. Klein	(916) 654-4822	jklein@energy.state.ca.us
Macro Development	Chris McClean	(916) 651-9006	CMclean@energy.state.ca.us
Data Development	Paul Deaver	(916) 651-0313	pdeaver@energy.state.ca.us
Fuel Price Forecast	Joel Klein	(916) 654-4822	jklein@energy.state.ca.us
Renewables Team Lead	Gerald Braun	(916) 653-4143	Gerald.braun@ucop.edu
Alternative Technologies Coordinator	John Hingtgen	(916) 651-9106	jhingtge@energy.state.ca.us
CONTRACTORS			
Aspen			
Project Manager	Richard McCann	(530) 757-6363	rmccann@aspeneg.com
Senior Technical Specialist	Will Walters	(818) 597-3407	WWalters@aspeneg.com
Senior Technical Specialist	John Candeleria	(702) 646-8282	JCandelaria@aspeneg.com
KEMA			
Principle Consultant	Charles O'Donnell	(513) 898-0787	charles.odonnell@US.KEMA.com
Principle Consultant	Valerie Nibler	(510) 891-0446	Valerie.Nibler@US.KEMA.com

APPENDIX H: Comments and Responses

August 25, 2009, Workshop

Morning Session

Comment by	Location in Webex	Comment	Response
Commissioner Byron	1h 5 m	Have you thought about how to incorporate PV with thermal storage into the COG Model?	Yes, KEMA generated two sets of costs for solar parabolic trough with 6-8 hours of energy storage. This increased both the capacity factor and the cost. There are important operational issues that need further clarification before this technology can be added into the model. As an aside, none of the proposed solar thermal plants in California include storage.
Commissioner Byron	1h 32m	The 2007 levelized cost are lower for certain technologies than the 2009 costs.	Much of this is because of the unforeseen escalation of construction costs. This was not fully captured in the *2007 IEPR*, but was better represented in 2009. However, in several cases, new assessments showed higher costs than in the 2007 assessment. This situation often arises when an alternative view is brought to bear on a study.
Tony Braun – counsel to California Municipal Utilities Association	1h 46m	For most renewable energy resources, a triangle model is used. Contracts are negotiated between a private developer and POUs to take advantage of available tax credits. Tax exempt financing is used to pay for the project output to take advantage of tax exempt securities. How much of this financing structure was reflected in the renewable cost numbers?	We did not incorporate that kind of project financing, particularly because the CMUA example is a project-specific case. The staff COG Model is designed to reflect parameters that can be generalized across projects. If we had a very detailed description of how that financing works, we could implement it into the model if its use is widespread. With more detailed descriptions, the model could be used to evaluate individual projects.

Comment by	Location in Webex	Comment	Response
Matt Barmack - Calpine	1h 48m	Some people at Lawrence Berkley Lab have done a lot of work on project finance structures for renewable. Have you taped into any of that work?	Staff looked at their report and used a fair amount of their information. The municipal co-financing model was not generalized to our study because we did not have sufficient information about the prevalence of these financing mechanisms. This model is designed to reflect parameters that can be generalized across projects. The values in this particular study are to be used for planning studies, not for evaluating specific identifiable projects.
Matt Barmack - Calpine	1h 48m	Are the differences in renewables using cash flow modeling and revenue requirements driven by the modeling, or the differences in assumptions about merchant cost of capital vs. IOU cost of capital?	It is in the modeling. Staff used identical assumptions except that of revenue requirement vs. cash flow.
Matt Barmack - Calpine	1h 50m	There is a lot of work out there that shows the equivalence of the cash flow and revenue requirement approach, using comparable assumptions, for investment decisions. I encourage you to look into that some more because I am not sure your result is correct.	Staff reviewed the study referenced by the commenter. That study only provided a simple mathematical model that assumed away many of the empirical issues that arise in project accounting. It did not address the differences in the debt and equity discount rates that arises in cash flow versus revenue requirement modeling, nor the non-linearities in the tax depreciation rates and renewable energy incentives.
Matt Barmack - Calpine	1h 52m	There are a lot of claims in the model that IOU facilities are cheaper than merchant facilities. I encourage you to use a little more neutral language. Maybe talk about the term of commitment instead of IOU vs. merchant.	The report explains how financing and tax benefits will affect the levelized costs for either a merchant, IOU or POU project.
Matt Barmack - Calpine	1h 53m	I think you can be much more guarded about your estimates of the installed costs of some of the newer conventional technologies. It was counter factual and counter intuitive that the installed costs of an H class combined cycle was lower than the costs of a normal combined cycle	The only H class and advanced CT cost estimates staff have are from the EIA, which assumes these technologies will be less expensive than the current technologies. Staff has much more knowledge and experience with the F class turbines. More knowledge on the H class turbines would allow us to make a better comparison.

Comment by	Location in Webex	Comment	Response
Ken Swane – Navigant consulting	1h 58m	The transmission access cost in your assumptions does not match up to what the CA ISO has on their March 2009 Tariff.	Staff used information from the March 2009 Tariff. A statewide average was used because the rates were quite close. Staff sourced this on the “plant data input page.”
Even Hughes – consultant in biomass and geothermal	2h	What is the basis for such a steep cost decline for solar PV?	Experience and learning curve effects. Maximum power point tracking and different inverter technologies. 12-18% of cost reduction over time attributed to learning effects. The model reflects a range of costs.
Matthew Campbell – Sun Power	2h 5m	Many years ago, the price of polysilicon and the global shortage of PV panels forced us off the experience curve. Recently we got back on the curve. Because the industry changes so frequently, we think the COG Model and assumptions should be updated on a real time basis rather than every two years.	The current analysis assumes a return to that experience curve. Staff can apply information if parties are willing to provide detailed assumptions for the technology modeling.
Roffy Manasean. - Southern California Edison	2h 12m	Why did they cost of nuclear increase so much from 2007 to 2009?	Most of the research for 2007 was done using the 2003 MIT landmark study. This 2009 analysis reflects expected costs in Europe and recent utilities’ analyses in the U.S. Also, many of the other data assumptions have changed in various reports since the 2007 IE.
Roffy Manasean. - Southern California Edison	2h 18m	The report says that one of the variable cost components for simple cycle units got shifted to a fixed cost component. It seems like a big difference because of the shift	It seems like a big shift internally, but the final total annual O&M cost number is roughly the same.
Craig Lewis – right cycle (advocacy consultant	2h 24m	$4.50 per watt for solar in model. Germany is making deals for under $4 per watt. How much attention is being given to how much faster the solar experience curve can be driven down once	The model reflects a range of costs, with $4.50 per watt only the middle of that range. Please review the full range that reflects the projects assessment. There are many effects in the market that can drive the experience curve. A feed-in-tariff could drive

Comment by	Location in Webex	Comment	Response
agency AB 1106)		we get a comprehensive feed-in-tariff in California?	costs down, and those effects probably are encompassed in the range of forecasted costs contained in the model.

Docketed Comments

Comment by	Comment	Response
Richard Murray – Landscape Architects, Environmental Planners	Energy close to its point of use can use existing infrastructure with minor modifications; this can save on the cost of new construction. Line energy losses are roughly 7.5% through transmission from place to place.	The comment is valid, and there is a substantial body of analysis dealing with the avoided costs of distributed deployment of renewables. However, this is not applicable to the staff COG Model, which is intended to cover only utility-scale plants that sell their entire output to the bulk power market. Smaller scale PV plants are usually intended to serve customer loads, at least in part, and would produce these types of line loss savings and often have different financing and operational considerations as a result.
Richard Murray – Landscape Architects, Environmental Planners	Bare land or low yield farm land could be utilized for PV when other crops are unavailable. PV energy farming is equally as important to our economy as other crops. PV farming would be listed under schedule B of the Williamson act which lists uses acceptable by different counties.	This is a policy issue beyond the scope of the technical analysis used to develop this model. This issue should be addressed as a policy issue in the IEPR proceeding
Richard Murray – Landscape Architects, Environmental Planners	The market price references (MPR) are tied to the costs associated with new natural gas-fired power plants. The PG&E small renewable generator power purchase agreement uses only the MPR without considering other inflation costs estimated by the CPUC. The small entrepreneur will need assistance through adjusted MPR, low interest loans, or governmental help.	While the COG Model could be used to compute the MPR for the CPUC, that agency chooses to use its own model. The policy on how solar developers should be compensated is beyond the scope of the technical analysis used to develop this model.
Matt Barmack - Calpine	The treatment of financing costs is imbalanced and has a bias towards IOUs. The model assumes limits on the contract term for merchant plants. The model ignores the fact that low financing costs reflect buyer's commitments to pay for the majority or all the capital costs of a project. A merchant plant with similar PPA terms as an IOU would have similar costs. The model ignores the fact that rate payers tend to absorb cost	The model is designed to compute only the cash costs of the generation technology in question and leaves out many other factors that are relevant to selecting among technologies, including relative risk burdens associated with ownership, relative environmental impacts, and differences in operational characteristics and how that fits with system requirements. Such a model is beyond anyone's capability to design in this format. The results from this model should never be used to make simple

Comment by	Comment	Response
	over-runs associated with IOUs while investors tend to absorb cost over-runs associated with merchant plants.	comparisons between technologies and ownership.
Matt Barmack - Calpine	The draft report says that POU plants are the cheapest to finance because of lower financing costs and tax exemptions. Tax exemptions only shift the capital costs from rate payers and developers to tax payers.	Again, the staff COG Model is designed to access relative costs, although we attempted to identify these cost components.
Matt Barmack - Calpine	The costs of H class CCGTs are virtually unknown. Also the same story for the LMS100 turbines for small simple cycle facilities. We believe these estimates should be tagged as “speculative” in the report.	We agree that the costs for the advanced CC and CT designs are less reliable than for the F frame and aeroderivative turbines where there is a considerable amount of actual project information. We will add a comment to that effect in the Report.
Richard Raushenbush - Greenvolts	What is the basis for the 27% capacity factor for Solar PV (single axis) in table 11? Was DC or AC output used in the calculation? We think the estimates may be understated. If converting DC to AC, how were the losses of that conversion calculated?	The capacity factor calculated using AC and DC parameters should be comparable to within 5%, with the AC capacity factor lower. Staff believe that 27% is in the range supported by project experience but would acknowledge that higher <u>and lower</u> results are to be expected depending on project siting and design.
Richard Raushenbush - Greenvolts	What is the basis for the 22.4% plant side losses for solar PV (single axis) in table 11? Does this number reflect the conversion of DC to AC output and other losses? If this is the case, we believe the report may be double counting the losses.	Plant side losses were derived by considering expected module performance plus thermal degradation. Inverter losses were accounted for by using expected performance charts common in the solar industry for inverters. The inverter losses were then compared to other representative projects in the consultant’s database for comparative accuracy and to verify agreement
Richard Raushenbush - Greenvolts	We believe that the assumption of 5% transmission losses for renewable and 2.09% for fossil fuel plants is too simplistic and can create an inaccurate cost comparison. This number should be based on the distance from load center. We believe the transmission losses should be lower for PV as many plants can be built close to the load center.	The losses were based on averages from CAISO data matched with the likely location of renewables around the state. While some PV may be located near load centers, the majority of proposed projects are located in desert regions far from load centers. The model is constructed to reflect general assumptions, not project specific or optimistic assumptions. The loss calculations reflect this premise.

Comment by	Comment	Response
Mary Hoffman – Solutions for Utilities, Inc	The KEMA report uses a gross capacity 25 MHW and 100 MW for solar PV plants. It is inaccurate to compare various cost components of solar PV plants with different capacities.	The Energy Commission staff agrees.
Mary Hoffman – Solutions for Utilities, Inc	The feed-in-tariff program can be very successful for smaller size solar PV plants. The report should be expanded to include costs for the 1-3 MW solar PV single axis plants.	The Energy Commission staff agrees and will revise the KEMA report. However, the COG Model is intended to cover only utility-scale plants that sell their entire output to the bulk power market. Smaller scale PV plants are usually intended to serve customer loads, at least in part, and often have different financing and operational considerations as a result.
Mary Hoffman – Solutions for Utilities, Inc	Why is “instant costs” used instead of “installed costs”? Installed costs incorporate construction costs, and I believe this would be a more appropriate cost measure.	The instant cost used in the COG Model includes all construction and pre-construction costs. The Model uses instant cost to produce installed cost. The conversion from instant to installed cost covers only the cost of the construction loan (AFUDC) and sales tax.
Mary Hoffman – Solutions for Utilities, Inc	Are shipping charges for all materials during construction of the plant included in the model? For smaller facilities, they are 1.5% - 2% of the cost of materials delivered to the site.	All construction and preconstruction costs, including shipping, are included in the estimate of instant cost. Note that the COG Model does not address small scale plants; it only calculates costs for utility-scale plants selling 100% of output to the bulk power market.
Mary Hoffman – Solutions for Utilities, Inc	For solar PV, ad valorem taxes are 0%. The yearly taxes to the county assessor on the unsecured equipment are 1.07%. Shouldn’t the 1.07% be calculated into ad valorem? Also, The KEMA report, page 96, shows no real property taxes nor ad valorem taxes; are these calculated elsewhere?	The ad valorem estimate is not a part of the KEMA Report. It is used only in the staff COG Model, and is shown in the staff COG Report as a component of the levelized cost. See Tables 6 and 7 and also Appendix A. The 1.07% comes from the BOE and does not distinguish between secured and unsecured property tax. The state property tax exemption for solar applies to all property.
Mary Hoffman – Solutions for Utilities, Inc	Page 52 of the COG report has “insurance “assumed at 0.6%. This is ok for solar PV facilities of 25 MW–100 MW size, but will not be accurate for facilities in the size of 1 MW–3 MW.	The 0.6% is used in the staff COG Model to calculate the levelized cost for utility scale central station technologies. Levelized costs were not calculated for the size of 1–3 MW. Therefore, insurance costs were not estimated. It would be expected that they would be

Comment by	Comment	Response
		a different value.
Mary Hoffman – Solutions for Utilities, Inc	What rates have been used to determine worker's compensation calculations for labor during construction and after the project is online? SCIF has raised worker's compensation rates for construction trades over the past few years. Has this been accounted for in the model? Also, premiums for workers compensation will vary widely based on the total dollar of premium paid per year by the employer. Has this been accounted for in the model?	The model uses cost build-up information that accounts for general categories of cost experience. KEMA consultants were not asked to provide detailed cost build-ups for each energy supply option. For the gas-fired plants, labor compensation rates are based on the Pacific Region estimates by job classification published by the Bureau of Labor Statistics. (USBLS, Employer Costs for Employee Compensation, Historical Listing (Quarterly), March 12, 2009.) For the other technologies, construction and operational costs are estimated on an aggregated basis and do not reflect summation of individual components. However, the estimates do reflect the recent escalation in construction costs, which have several factors driving those increases. For the gas-fired plants, labor compensation rates are based on the Pacific Region estimates by job classification published by the Bureau of Labor Statistics. (USBLS, Employer Costs for Employee Compensation, Historical Listing (Quarterly), March 12, 2009.) For the other technologies, construction and operational costs are estimated on an aggregated basis and do not reflect summation of individual components. However, the estimates do reflect the recent escalation in construction costs, which have several factors driving those increases.
Mary Hoffman – Solutions for Utilities, Inc	For solar PV facilities: how is it determined which facilities have permit fees, report costs, and or animal and plant life mitigation fees? Also, permit fees should be analyzed separately for smaller sized projects (1 – 3 MW) as they are proportionately more expensive.	The model uses cost build-up information that accounts for general categories of cost experience. Commission consultants were not asked to provide detailed cost build-ups for each energy supply option
Mary Hoffman – Solutions for	Page 38, table 8 of the staff report for merchant plants has a solar PV tax benefit of $334.28 MWh. Page 26, Table 6 of the staff report has "average levelized cost	The $334.28 per MWh (in Table 8) is calculated by running the COG Model with and without tax benefits (accelerated depreciation, tax credits and property taxes). The $141.44 per

Comment by	Comment	Response
Utilities, Inc	component for in service 2009- merchant plants" taxes as "-$141.44 per MWh. How were these two numbers calculated?	MWh of Table 6 is calculated by the COG Model as a part of the levelized cost calculations. The actual tax calculation is mathematically complex and not easy to characterize. It will, however, be made available in the soon to be released User's Guide for the COG Model.
Mary Hoffman – Solutions for Utilities, Inc	The staff report says the model has the ability to include the cost of carbon in its calculation, but this function has not been used to calculate how carbon adders may affect levelized cost estimates. This calculation should be performed and available to all interested parties.	The COGModel has the ability to incorporate the cost of carbon, not to calculate it. The actual costs will be developed in future Energy Commission studies and be the subject of workshops and/or hearings.
Mary Hoffman – Solutions for Utilities, Inc	The Staff Report, on page 3, Table 1: "Summary of Average Levelized Costs - In Service in 2009," "Merchant," Solar PV, based on a 25-MW capacity facility is indicated as 26.22 cents per kWh. The cost of a 1 – 3 MW solar pv plant would be higher. Staff and KEMA should include the costs of these smaller facilities in their analysis.	The 1-3 MW size will be added to the KEMA Report. However, the COG Model is intended to cover only utility-scale plants that sell their entire output to the bulk power market. Smaller scale PV plants are usually intended to serve customer loads, at least in part, and often have different financing and operational considerations as a
Matthew Campbell – Sun Power	SunPower proposes that the CEC include both central station and distributed PV power plants as separate line items in its COG Model. The two resource types have different strengths with distributed power plants being faster to interconnect and permit but achieving lower economies of scale than central station plants.	The Energy Commission staff is considering adding distributed generation to its COG Model for future IEPRs.
Matthew Campbell – Sun Power	We propose that the COGs consider a 20 MW distributed PV power plant and a 200 MW central station PV power plant	Staff agree that experience gained over the next years may provide a sound basis for implementing the recommendation. Staff did not compare costs for different plant sizes since insufficient experience exists to validate cost estimates.
Matthew Campbell – Sun Power	Sun Power recommends increasing the assumed capacity factor for the 25MW single-axis PV system from 27% to 30% (AC). The 30% capacity factor is	Staff believe 27% is in the range supported by project experience, but would acknowledge that higher and lower results are to be expected depending on project siting and design.

Comment by	Comment	Response
	similar to what we anticipate for our California PV power plants such as the 210 MW California Valley Solar Ranch. SunPower has studied 10 years of historical annual variation in solar resource in the Mojave Desert and anticipates an annual variation in capacity factor of +-5% around the 30 year average used to estimate capacity factors.	
Matthew Campbell – Sun Power	SunPower recommends increasing the 20 year equipment and depreciation life to 30 years, the same value used for wind turbines in the draft report. Unlike wind, PV power plants have very little mechanical wear and maintenance requirements and operate under relatively benign conditions. PV panels and trackers are well established technologies with over thirty years of demonstrated performance.	Staff agrees conceptually, but did not have sufficient visibility to financing packages for utility scale PV projects to validate more aggressive assumptions.
Matthew Campbell – Sun Power	SunPower recommends a debt term of 20 years, the same as assumed for wind. Both wind and large-scale PV plants are financed using standard power project finance regimes and share similar characteristics.	Staff recognizes that aggressive financing assumptions have been used for some larger PV projects. Staff does not have sufficient visibility to financing packages for utility scale (>20MW) PV projects to validate more aggressive assumptions at this time.
Matthew Campbell – Sun Power	In the draft report an O&M cost of $68/kW per year is assumed for both a PV and CSP power plant. Sun Power's experience in operating more than 300 MW of solar power plants using a wide variety of system technology around the world is that the O&M cost for PV is dramatically lower than CSP. We recommend using an assumed value for the study of$30/kWp/year.	While there is some field experience with large CSP plants there is little or none with comparably sized PV plants. Staff recognizes the need to monitor experience for both options closely as it accumulates.
Matthew Campbell – Sun Power	Owing to the scaling of very large scale PV module factories, the introduction of new technologies, and the availability of sufficient silicon feedstock, the price of PV power plants is falling dramatically.	Module price as a proxy for cost would suggest module costs continue to trend strongly downward, but fully built-up module cost is not the sort of information we can access in the public domain.

Comment by	Comment	Response
PG&E	Future studies could be further enhanced by including an assessment of variability in costs of construction, both in terms of labor and materials	The COG Report provides this sensitivity through its range of high and low assumptions that reflect the cost factors identified by the commenter.
PG&E	Should consider that cost information may be skewed by market conditions/value at a particular point in time if there is an over or under supply of particular components	This was recognized as a short coming in the *2007 IEPR*. The COG's instant cost calculations in the *2009 IEPR* adjusted for this.
PG&E	Combined cycles (CC) are more complex than simple cycle units. Intuitively this leads to the conclusion that CCs should cost more.	The cost per MW for CCs is lower than for CTs because the per MW cost for the steam turbine component of the CCs is about half that of the CT component, so the average of the CTs and the steam component will be lower than just the CT alone, even accounting for the higher additional costs.
PG&E	Would like to see levelized costs for combined cycle units with 60% capacity factors, as these units will probably help to integrate renewables.	The Energy Commission staff assessment of currently operating plants indicates the higher capacity factors of 70% for CCs with duct-firing and 75% without duct-firing. It would be helpful if PG&E could provide its assessment that leads to a 60% capacity factor, which reflects our earlier 2007 COG assessment.
PG&E	Would like to see evaluation of reciprocating technologies in future updates of the COG Report.	There are no "utility scale" uses of reciprocating engines. Those are all DG and community scale applications. However, the Energy Commission is considering augmenting future COG Reports to include these community scale technologies, and will keep your suggestion in mind.
PG&E	Would like to see a sensitivity analysis around the aggressive experience curve for both solar PV and solar thermal	The COG Report provides this sensitivity through its range of high and low assumptions.
PG&E	Would like to see a wide range of estimates for small hydro, that are supplemental to an existing project, in future COG Reports.	The COG Report provides this sensitivity through its range of high and low assumptions
SCE	Figure 3 of the draft staff report shows that solar resources are among the most costly resources when ranked by instant costs in 2010. Yet, their levelized cost	Only the simple cycle units have a larger $/MWh levelized cost than the solar units, not the combined cycle or any of the other conventional or renewable units. This has to do with the very low

Comment by	Comment	Response
	is below both conventional and simple cycle resources. This result is counterintuitive and misleading	capacity factors for CTs versus other technologies. It is always problematic to compare peakers to intermediate and base load units as they serve different purposes. It might be helpful for you to examine the cost comparison on a $/kW-Year basis in Table B-4.
SCE	The choice of plant used for the natural gas resources is inappropriate. The simple cycle gas turbine uses a GE LM6000 as compared to an F-Class turbine, which is less costly.	The LM 6000 simple cycle units were used as our standard, rather than F-Class because there is not a single F-Class simple cycle operating in California. This is explained on page C-1 of Appendix C. You should also be aware that the CTs recently constructed by Edison at four different sites were all LM6000s.
SCE	The combined cycle unit chosen is based on an F-Frame unit but the chosen (100 MW) size does not allow for the economies of scale a 500 MW unit would provide.	The combined cycle units in the COG Report are based on two 175 MW turbines, not 100 MW. The COG Report's combined cycle sizes of 500 MW for a non duct-fired unit and 550 MW for a duct-fired unit are the most commonly proposed and built sizes in California going back to 1999
SCE	The input cost assumptions for the various technologies may be inaccurate. The CEC should cross-validate the analysis assumptions against other recent studies to understand the nature of the differences.	The Energy Commission staff has made the most extensive study of technology costs today using all known data. This is particularly true for the gas-fired units which rely on the actual survey of California developers for the *2007 IEPR* plus a survey of all known available estimates for the 2009. We know of no additional sources of data.
SCE	The methodology for the conversion to levelized cost may be inappropriate.	The Energy Commission staff COG Model is in its third generation and has undergone scrutiny of many reviewers. Staff has benchmarked the Model against other models, including the SCE Model used in the MPR and found it to be within 1%. The only components that did not exactly match were equity and its effect on corporate taxes. This was found to be traceable to the SCE Model using cash-flow and the COG Model using revenue requirement. For the 2009 COG we have changed our merchant modeling to cash-flow so the models should now match even more closely. However, differences may remain in assumptions about

Comment by	Comment	Response
		contract terms and cost escalations. Staff would appreciate more precise and documented comments about these concerns so that they can be addressed.
SCE	Levelized costs may not appropriately take into account the value of energy	A COG Model by definition reflects the cost of the technology, not the value of the energy to the system. This would require a system model, such as a production cost model.
SCE	Information for the nuclear technologies in the draft staff report does not appear to be correct. Table 19 of the draft staff report identifies the book life for the AP1000 Pressurized Water Reactor (PWR) as 20 years and the equipment life as 40 years.	SCE is correct. The book life for nuclear should be 40 years and the equipment life 60 years. This was an error in Table 19 due to the data for nuclear being inadvertently switched with coal-IGCC during the preparation of the table. This error is in the table only and not reflected in the levelized costs.
SCE	Figure 20 in the draft staff report shows that the levelized cost for AP 1000 PWR increased by approximately 100% since the issuance of the 2007 IEPR. SCE's understanding is that the instant costs increased, but only by about 30%. Upon discussion with the Energy Commission staff, we understand that the version of technology utilized for this report is different from that used in the *2007 IEPR*. Therefore, this is not a valid comparison, and we recommend that the comparison between the two IEPRs be removed	In the 2007 work, a generic reactor was used for the costs estimates. In 2009, the CEC consultant made a thorough analysis of the nuclear technologies most likely to be implemented within the state over the next twenty years and concluded that at this time, the AP-1000 would be the most likely implementation. The 2009 cost estimates are therefore based on more specific estimation of feasible nuclear technology implementation than the 2007 estimates were. The comparison of these technologies across COG Reports is problematic where technologies are changing. That does not mean that the comparisons are meaningless. It is important for reviewers to be made aware of our changes in estimates. The nuclear costs are particularly problematic as they are subject to change and cannot be known with any real certainty – thus the need for our bandwidth costs in the COG Report. However, we can modify the COG Report to state this difference.
SCE	EIA Instant costs vary dramatically from the Energy Commission's estimates.	This is to be expected, particularly for alternative technologies, where costs can be changing dramatically over time, assessments are made based on different data samplings, and the COG Report is based on California specific costs, where EIA costs are national

Comment by	Comment	Response
		averages. Staff feels that its estimates are superior, particularly for California gas-fired units where they reflect actual survey data. We devoted resources to our California specific assessment that the EIA could not possibly have duplicated. However, all of this misses the primary message of the COG Report that single values cannot be known with certainty, as suggested by the EIA figure you provided.
SCE	The Energy Commission should explicitly recognize that resources are not interchangeable.	The Energy Commission staff does recognize this fact. This is why the report includes Figures 9–12 to illustrate this difference, even if on a general level. This was emphasized again in the workshop. Staff agrees that this is a salient point and will make an additional effort to further emphasize this point in the COG Report.
Elaine Chang, DrPh - SCAQMD	It is unclear whether the report has addressed the cost impacts of environmental externalities.	This was not within the scope of the COG work. However, environmental permitting and compliance costs were included where appropriate and known. These included air quality permitting costs.
Elaine Chang, DrPh - SCAQMD	According to the report (page 9), the cost of carbon capture and sequestration was not included.	This was not included due to the fact that the Energy Commission has not yet established the necessary data. This will involve workshops and/or hearings in the future.
Elaine Chang, DrPh - SCAQMD	It is unclear whether the cost of offsets were accounted for.	The cost of offsets were included in Chapter 2, Assumptions. The estimated emission rates can be found in Tables 11-13 and the corresponding estimated costs are in Tables 14 -16.