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California Energy Commission

FINAL STAFF REPORT

ESTIMATED COST OF NEW RENEWABLE AND FOSSIL GENERATION IN CALIFORNIA

CALIFORNIA ENERGY COMMISSION

Edmund G. Brown Jr., Governor

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CALIFORNIA ENERGY COMMISSION

Ivin Rhyne
Joel Klein
Bryan Neff
Primary Authors

Ivin Rhyne
Project Manager

Ivin Rhyne
Office Manager
SUPPLY ANALYSIS OFFICE

Sylvia Bender
Deputy Director
ENERGY ASSESSMENTS DIVISION

Robert P. Oglesby
Executive Director

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ABSTRACT

This report summarizes the cost trends for utility-scale generation resources that may be built in California over the next decade. These resources include solar, wind, geothermal, biomass, and gas-fired technologies. Trends in technology, permitting, construction, and financing costs are considered. The instant and installed costs for each type of technology are presented for investor-owned, publicly owned, and merchant-owned generation resources. Finally, the levelized costs necessary to provide financial incentive for development are estimated using an updated Cost of Generation Model. These values are presented with both deterministic and probabilistic ranges of potential costs over the next 10 years.

Keywords: Electricity, natural gas, investor-owned utilities, publicly owned utilities, merchant power plants, instant cost, installed cost, levelized cost, probabilistic estimations, wind, solar, biomass, geothermal, solar thermal, energy storage

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EXECUTIVE SUMMARY

This report presents estimates of the current and future costs to build and operate new utility-scale electric power plants over the next decade. These estimates are developed primarily for use at the California Energy Commission to ensure use of common assumptions. These estimates are also used in multiple studies, including procurement planning studies conducted at the California Public Utilities Commission, transmission planning studies conducted at the California Independent System Operator, within the Western Electric Coordinating Council, the California Board of Equalization for property assessments, by the California Air Resources Board, and a variety of related consulting and academic studies.

The cost to build and operate a new power plant in California depends on which technology is built, where in California it is located, how much it costs to finance the project (typically a function of who owns it), and how much of the time the plant runs. The amount of energy a power plant produces over its lifetime can depend on either its cost to operate relative to other power plants (such as for fossil-fueled generators who must participate in a competitive market) or the availability of the energy source (such as for renewable generators).

The authors have limited the scope of this report to estimating the costs to the developer rather than to the utility or ratepayer. The electric grid is a large and dynamic system; estimating the effects of how adding a resource at one location alters the operation of the surrounding grid would require significant additional analysis that is beyond the current limitations of time and resources within the Energy Commission. Further, any attempt to estimate value to the utility or to the state would require dramatic expansion of the assumptions to capture those values, such as environmental benefits, economic or jobs benefits, or grid reliability benefits, and is beyond the scope of this project.

Technology Descriptions and Trends

This report considers the following utility-scale technologies:

- Solar photovoltaic.
- Solar thermal.
- Wind.
- Geothermal.
- Biomass.
- Natural gas-fired.

Solar Photovoltaic Technology

Solar photovoltaic technologies are an important and a growing portion of California's electricity infrastructure. This report focuses on two utility-scale photovoltaic technologies:

crystalline silicone single axis tracking systems (100 megawatt and 20 megawatt) and thin-film solar fixed axis systems (100 megawatt and 20 megawatt).

The costs for photovoltaic modules have come down dramatically in the last few years, leading to much lower system prices for utility-scale photovoltaic plants in California and elsewhere. The solar industry is experiencing a roughly 20 percent reduction in costs for each doubling of production. The primary drivers in these expected reductions are research and development, and the natural process of learning as the industry continues to gain experience. Research and development is being driven by the United States Department of Energy SunShot Initiative, which is targeting $1 per watt for utility-scale solar photovoltaic systems. Costs for thin–film photovoltaic systems are expected to decline at a steeper rate than those for crystalline silicone photovoltaic systems. However, both expected declines are partially due to the highly interrelated research and production improvement associated with photovoltaic components.

Solar Thermal Technology

Solar thermal plants, also known as *concentrating solar power plants*, collect and convert solar energy into power using conventional steam turbines. There are two predominant commercial embodiments of solar thermal plants, parabolic troughs and solar towers, both of which collect sunlight over large "solar fields." The captured solar energy generates heat, which is transferred to a working fluid (such as pressurized oil). The working fluid is used to generate steam, which is routed through steam turbines to generate electricity.

Both trough and tower concentrating solar power plants may include *thermal energy storage*. Thermal energy storage stores the working fluid at high temperatures and allows the plant operator to have some control over when electricity is generated, thereby increasing the plant's dispatchability. Energy collected earlier in the day can be drawn from storage to generate additional power in the afternoon even as solar input declines. Thermal energy storage is an important concentrating solar power component since it adds both significant additional capital costs and significant expansion of the operational profile, greatly reducing the cost of energy. This report considers 100 megawatt solar tower plants (without storage, with 6 hours of thermal energy storage, and with 11 hours of thermal energy storage) and 250 megawatt parabolic trough plants (without storage, and with 6 hours of thermal energy storage).

While solar thermal plants were featured prominently in California, projects begun under the 2009 American Recovery and Reinvestment Act have declined as those funds are no longer available. This reduction tends to slow the learning process and, therefore, makes cost declines more gradual than those experienced by the solar photovoltaic industry. However, there is strong interest among renewable developers to find ways to capture the maximum value of solar energy; thermal technologies with storage allow the plant operator to participate in the electricity marketplace in the evening hours after solar photovoltaic plants are no longer generating.

Both solar tower plants and parabolic trough plants are projected to a decline in capital costs, driven by a steady growth of investment from developers who will push to lower costs and maximize value. The largest declines are expected in plants with large storage capacities, as these hold the most promise for developers, yet higher capital costs.

Wind Technology

Wind generation technologies, like solar, have been the subject of much study and discussion over the last several years. This report focuses on California-specific lifetime costs of building and operating 100 megawatt wind generation resources for wind speed Classes 3 and 4.

Wind technology costs have shown volatility in recent history, with project costs increasing between 2004 and 2010 before beginning a decline. Factors such as the move toward increased rotor diameter and the declining availability of high-quality wind resources have played a role in this trend. While Class 3 wind projects typically have higher equipment costs than Class 4 wind projects, progress in rotor and generator technologies has made it possible for Class 3 wind projects to show lower lifetime costs due to the ability of these projects to harness lower-speed winds, resulting in higher capacity factors. Equipment costs for both Class 3 and 4 wind projects are expected to show significant declines.

Geothermal Technology

Geothermal technologies remain viable in California, although they are subject to some limitations that may reduce the number of sites developed in the state. The most likely technologies to be developed in California are binary and flash. A *binary geothermal plant* uses the heat from the underlying geothermal resource to heat another fluid that is then used to turn a generator. A *flash geothermal plant* uses the fluids drawn directly from the ground that are converted to steam through a "flash" process of dropping the surrounding pressure and then turning a generator. This report analyzes 30 megawatt binary and flash geothermal plants.

Geothermal resource costs are driven largely by the highly variable and significant costs of drilling and well development. These costs are unique to each site and represent a significant risk on the part of the developer. While a successful well may be able to produce electricity at low cost, other wells in the same area may require much more investment in time and resources before they are producing efficiently. Costs for new geothermal plants are projected to increase slightly over the coming years. While limitations of location and drilling are unlikely to change in California, there is renewed interest in the Salton Sea area with EnergySource's 49.9 MW geothermal plant coming on-line in 2012.

Biomass Technology

Biomass technologies are plants that use biological resources, such as forestry waste or farming by-products, to produce electricity through thermal and chemical processes. These technologies are in limited production here in California. While these technologies are designed to harness biological by-products sustainably, they suffer from the limitation of requiring large, reliable fuel sources to produce energy economically. This report focuses on the only commercially available utility-scale direct combustion biomass technology, a 50 MW fluidized bed boiler.

Equipment cost of the boiler island, the location where biomass combustion occurs, is a critical cost driver that can account for roughly 40 to 60 percent of the overall plant cost, depending on the type of biomass combusted and the need for postcombustion pollution controls. Thus, the choice of source and type of fuels to be combusted is an important equipment cost driver. In addition, the escalation trends for raw materials used in manufacturing the boiler island, primarily steel cost, are factors that can influence delivered boiler island cost.

In addition, most current biomass fuel supply contracts are short-term and can entail varying fuel qualities. A key cost barrier is the ability to develop and achieve performance on long-term (for example, five years duration and longer) fuel supply contracts for available fuel sources. Further, the high cost of transporting the fuel from the origination site to the generation site, which exposes the producer to the volatile market for diesel or other petroleum fuels, can add significant costs and affect project viability.

Natural Gas-Fired Technology

Natural gas-fired generation remains the backbone of California's electricity generation portfolio. While the majority of new generation in the last few years has been renewable, targeted investments in gas-fired generation continue to be discussed and approved on a limited basis by the California Public Utilities Commission. Many of these targeted investments have been to meet local reliability and operational flexibility needs, as opposed to providing energy.

The technologies considered to be viable at this time are:

- Conventional combustion turbine—one LM6000 turbine (49.9 megawatts).
- Conventional combustion turbine—two LM6000 turbines (100 megawatts).
- Advanced combustion turbines—two LMS100 turbines (200 megawatts).
- Conventional combined cycle (no duct firing)—two F-Class turbines (500 megawatts).
- Conventional combined cycle (duct firing)—two F-Class turbines (550 megawatts).

Most combined cycle power plants that were built expecting to operate 80 percent of the time or more have seen the actual operation well below this threshold. Instead of base load, these plants have been operated as *load-following*, meaning they ramp up and down through the day tracking the overall trend in electricity demand as consumers respond to cooling, heating, and lighting needs. As a result of these lower capacity factors, the number of combined cycle power plants being built in California recently has declined as more uncertainty in the ability to recover the cost of construction and operation exists.

The underlying combustion technologies are mature and the prices stable. In addition to the uncertainty driven by capacity factor, both combined cycle and combustion turbine power plants need to participate in emission credit markets. The trend toward both increasing costs of particulate and volatile emission credits and greenhouse gas emission credits is likely to add significant costs over the lifetime of a fossil-fueled power plant.

Financing Costs

The costs of financing and taxes are major components of the cost of constructing and owning a power plant.

This report considers three financing options:

- Merchant.
- Investor-owned utility.
- Publicly owned utility.

The financing of each project is highly variable depending on the project sponsor, the markets, the terms and conditions of power sales agreements, and the technology type. There are several trends associated with financing that are likely to influence these costs. **Table 1** shows the assumed financing costs for each type of investor. Merchant and IOUs finance projects based on debt and equity. POU plants do not rely on equity financing as they rely solely on debt (issue bonds). **Table 2** shows the estimated Merchant cost of equity.

Table 1: Capital Cost Structure

Mid Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	33%	13.25%	4.52%	6.17%
Merchant Alternative	40%	Variable*	Variable*	Variable*
IOU	55.%	10.04%	5.28%	6.93%
POU	N/A	N/A	3.20%	3.20%

Source: Energy Commission.

Variable* financial structures are shown in **Table 2**.

Table 2: Financial Parameters for Merchant-Owned Renewables

Mid Case						
Technology	Cost of Equity			Debt		WACC
	Developer's Cost	Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass & Geothermal	13.25%	8.00%	12.41%	60.00%	6.31%	7.21%
Solar Technologies	13.25%	8.00%	12.41%	60.00%	5.91%	7.07%
Wind Technologies	13.25%	8.00%	11.34%	60.00%	5.91%	6.64%

Source: Energy Commission.

The cost of money for merchant and investor-owned utility plants is melding of two sources: equity (such as ownership shares) and debt (such as corporate bonds or loans from large banks). The publicly owned utility cost is therefore much lower as these utilities are allowed to raise money solely through debt. This report focuses primarily on merchant developers because private owners are by far the dominant developers in the marketplace.

The *weighted cost of equity* for a merchant plant is a combination of the developer's and investor's cost of equity. This occurs when a small company develops a project but does not have sufficient tax liabilities to take full advantage of the tax credits and works with a larger company that is capable of using the remainder of the tax credit.

Instant, Installed, and Levelized Costs

This report summarizes a large array of assumptions and translates them into *instant cost, installed cost,* and *levelized cost*.

- *Instant cost is the cost to* build a power plant if it could be built overnight, sometime characterized as *overnight cost*. It includes cost of all equipment, permitting, and construction; that is all the costs except for the financing of the construction.
- *Installed cost* is the instant costs plus the construction loan, including development fees.
- *Levelized cost* reflects the lifetime cost of operations and maintenance combined with the installed cost expressed as a constant stream of costs per unit of value over the lifetime of the plant. It is most commonly measured in dollars per megawatt-hour, but sometimes reported at dollars per kilowatt-year.

The cost of any new power plant is a result of numerous, sometimes intertwined, factors relating to changing market conditions, labor and resource costs, regulatory issues, and local factors such as real estate market forces and air, water, and land-use planning. Staff constructed a mid-cost case using the best current estimate for costs that are applicable across the state for all factors involved in estimating the future costs of new generation. In the previous *Cost of Generation Report*, staff built a high-cost case and a low-cost case around that mid-cost case, using the simultaneous highest cost and lowest cost factors. In this *Cost of Generation Report*, staff established a more narrow range of more likely cost values using the Analytica Cost of Generation Analysis Tool.

Instant and Installed Costs

Table 3 summarizes the 2013 mid case instant and installed costs. The instant costs for all three developers are assumed to be the same. However, the installed costs differ, reflecting the differing costs of the financing the construction.

Table 3: Summary of 2013 Instant and Installed Costs – Mid Case

In-Service Year = 2013 (Nominal $)	Instant Cost	Installed Costs		
		Merchant	IOU	POU
Generation Turbine 49.9 MW	$1,224	$1,310	$1,320	$1,312
Generation Turbine 100 MW	$1,220	$1,305	$1,316	$1,307
Generation Turbine—Advanced 200 MW	$987	$1,069	$1,085	$1,064
Combined Cycle—2 CTs No Duct Firing 500 MW	$1,000	$1,088	$1,107	$1,084
Combined Cycle—2 CTs With Duct Firing 550 MW	$981	$1,068	$1,085	$1,064
Biomass Fluidized Bed Boiler 50 MW	$4,498	$5,068	$5,103	$4,917
Geothermal Binary 30 MW	$5,342	$6,743	$6,865	$6,160
Geothermal Flash 30 MW	$6,039	$7,382	$7,493	$6,858
Solar Parabolic Trough W/O Storage 250 MW	$3,819	$4,259	$4,301	$4,147
Solar Parabolic Trough With Storage 250 MW	$5,465	$6,094	$6,155	$5,935
Solar Power Tower W/O Storage 100 MW	$4,166	$4,646	$4,692	$4,524
Solar Power Tower With Storage 100 MW 6 HRs	$5,833	$6,504	$6,569	$6,334
Solar Power Tower With Storage 100 MW 11 HRs	$6,487	$7,234	$7,305	$7,044
Solar Photovoltaic (Thin-Film) 100 MW	$3,144	$3,366	$3,383	$3,322
Solar Photovoltaic (Single Axis) 100 MW	$3,660	$3,918	$3,938	$3,867
Solar Photovoltaic (Thin-Film) 20 MW	$3,469	$3,715	$3,733	$3,666
Solar Photovoltaic (Single Axis) 20 MW	$3,985	$4,267	$4,288	$4,210
Wind—Class 3 100 MW	$1,911	$2,074	$2,085	$2,044
Wind—Class 4 100 MW	$1,822	$1,978	$1,988	$1,950

Source: Cost of Generation Model.

Levelized Costs of Generation

Traditionally, levelized costs are presented using deterministic single-value estimates. In the *2009 Cost of Generation Report*, the Energy Commission presented levelized costs in three deterministic values: mid, high, and low. The high and low values presented too wide of variation to be useful. In this version, high and low levelized cost values are estimated using probabilistic analysis, while the mid case continues to be estimated in the traditional deterministic fashion. These high and low probabilistic estimates are developed using

Lumina's Analytica Model in conjunction with the Energy Commission's COG Model, designated as Analytica Cost of Generation Analysis Tool.

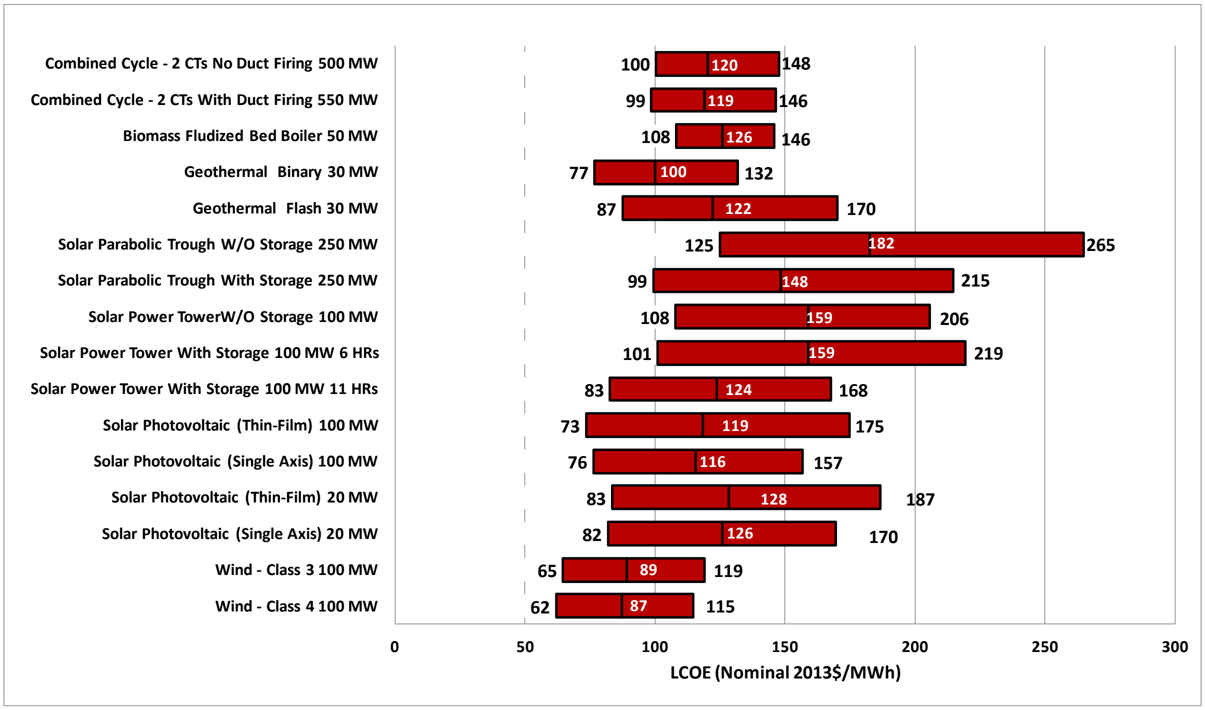
Table 4 summarizes the 2013 mid case levelized costs. **Figure 1** summarizes the corresponding high and low case levelized costs.

Table 4: Summary of 2013 Mid Case Levelized Costs

Start-Year = 2013 (Nominal $)	Size	Merchant		IOU		POU	
	MW	$/kW-Yr.	$/MWh	$/kW-Yr.	$/MWh	$/kW-Yr.	$/MWh
Generation Turbine 49.9 MW	49.9	275.66	662.81	185.13	2215.54	193.34	311.60
Generation Turbine 100 MW	100	273.83	660.52	183.47	2202.75	191.81	310.11
Generation Turbine - Advanced 200 MW	200	252.33	403.83	159.41	1266.91	200.67	215.62
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	551.42	116.51	495.20	104.54	482.63	102.35
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	548.14	115.81	492.86	104.05	481.32	102.08
Biomass Fluidized Bed Boiler 50 MW	50	812.34	122.04	941.97	141.53	820.03	123.54
Geothermal Binary 30 MW	30	561.31	90.63	743.97	120.21	519.74	84.98
Geothermal Flash 30 MW	30	653.36	112.48	851.61	146.72	627.91	109.50
Solar Parabolic Trough W/O Storage 250 MW	250	329.92	168.18	448.52	228.73	325.42	167.93
Solar Parabolic Trough With Storage 250 MW	250	405.52	127.40	601.76	189.12	423.90	134.81
Solar Power Tower W/O Storage 100 MW	100	342.48	152.58	471.26	210.04	336.00	151.53
Solar Power Tower With Storage 100 MW 6 HRs	100	421.46	145.52	630.53	217.79	440.07	153.81
Solar Power Tower With Storage 100 MW 11 HRs	100	459.85	114.06	692.04	171.72	479.73	120.45
Solar Photovoltaic (Thin-Film) 100 MW	100	206.11	111.07	315.22	170.00	219.97	121.30
Solar Photovoltaic (Single Axis) 100 MW	100	241.22	109.00	365.48	165.22	254.52	116.57
Solar Photovoltaic (Thin-Film) 20 MW	20	224.21	121.31	344.46	186.51	239.16	132.42
Solar Photovoltaic (Single Axis) 20 MW	20	259.52	117.74	394.71	179.16	273.72	125.86
Wind - Class 3 100 MW	100	181.75	85.12	223.75	104.74	160.77	75.80
Wind - Class 4 100 MW	100	173.08	84.31	213.61	103.99	153.55	75.29

Source: Cost of Generation Model.

Figure 1: Summary of 2013 Merchant Probabilistic High and Low Case Levelized Costs

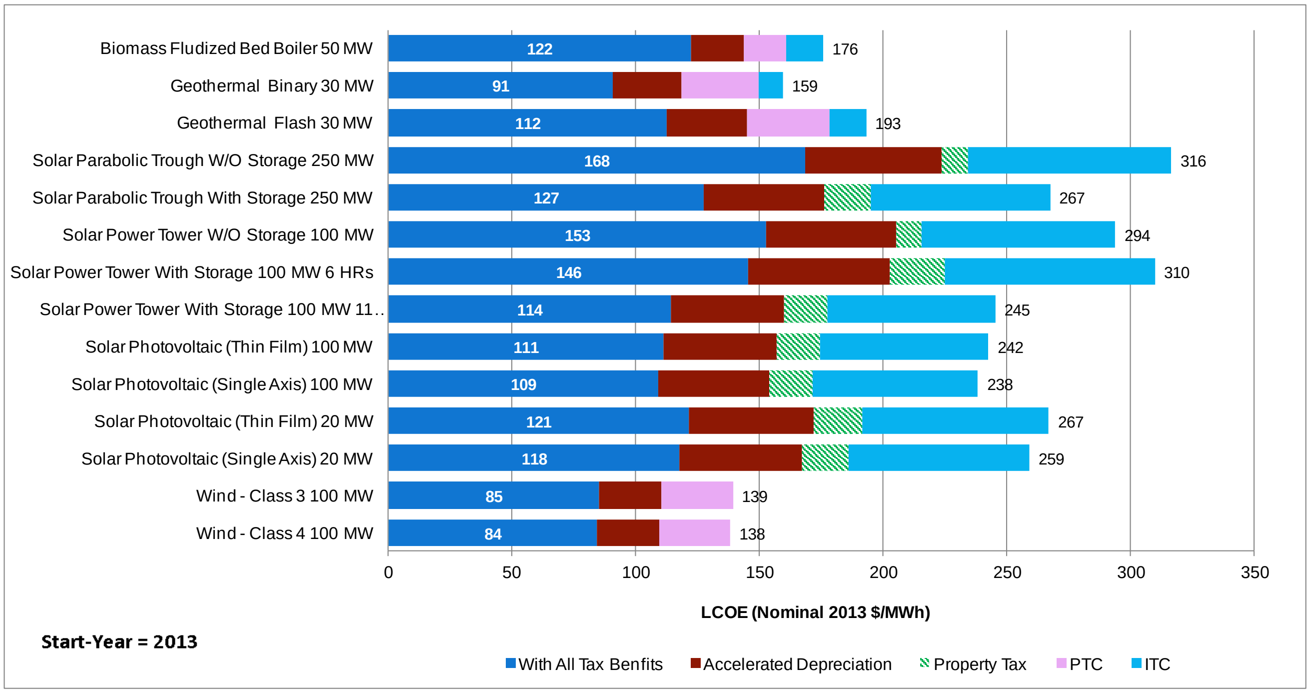


Source: Cost of Generation Model.

Tax Treatment

The treatment of taxes and tax benefits has significant effects on the total costs of various technologies. Accelerated depreciation, solar property tax exemption, the Renewable Electricity Production Tax Credit (PTC), and the Business Energy Investment Tax Credit (ITC) affect the cost of the different technologies to varying degrees. During the study period, there are various expiration dates for these incentives. Given price trends in the market place, this Report assumes no expiration of any tax incentives during the study period for its deterministic mid case. The PTC is available to all technologies except solar; however, it is the better option for wind only. All other technologies benefit more under the ITC. **Figure 2** summarizes the assumed tax benefits, reflecting the costs absent these tax incentives.

Figure 2: Summary of 2013 Tax Benefits on LCOE – Merchant Mid Case

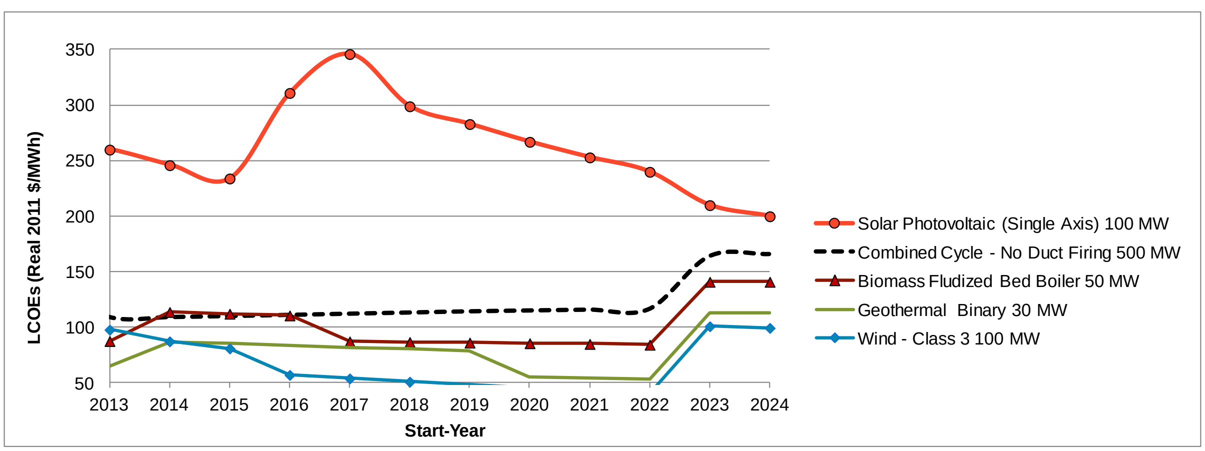


Source: Cost of Generation Model.

Changes Since the 2009 Report

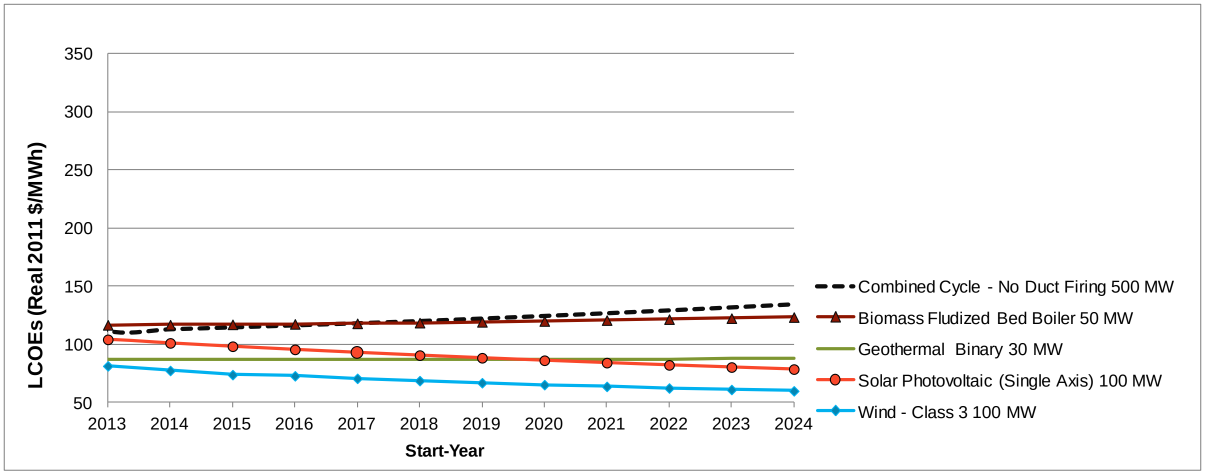
Figure 3 shows the *2009 Integrated Energy Policy Report* mid case levelized costs for selected technologies. **Figure 4** shows the corresponding levelized costs for the current *2013 Integrated Energy Policy Report*. The difference between the two figures is compounded by the assumed continuation of the various tax benefits.

Figure 3: Selected Levelized Costs in the *2009 IEPR*



Source: Cost of Generation Model.

Figure 4: Selected Levelized Costs for the Present *Integrated Energy Policy Report*



Source: Cost of Generation Model.

Emission Mitigation, Fuel, and Transmission Interconnection Costs

While each project and generation technology brings a unique set of costs and underlying trends, there are three cost components that are less dependent on the technology type. These include costs for environmental mitigation, such as emissions reduction credits (ERCs) that do not affect all technologies equally but are based on the emissions profile of the technology; fuels such as natural gas or biomass for power plants; and interconnection transmission equipment to deliver energy from the generator to the interconnection point.

Environmental Mitigation Costs

Environmental mitigation measures have become increasingly important components of power plant costs, for both fossil-fueled and renewable generators. For natural gas-fired generators, the largest compliance cost component is either criteria pollutant ERCs or greenhouse gas (GHG) costs, depending on the expected price trajectory for GHG credits. For renewable generators, the largest compliance cost components are habitat mitigation and land acquisition. Other compliance costs include the regulatory permit application, processing, and monitoring costs.

Table 5 shows the trend in ERC costs. It shows projected 2024 energy reduction credit costs as high as 12 percent of the total instant cost and 9 percent of the total levelized cost. **Table 6** shows the trend in greenhouse gas costs. It shows projected 2024 GHG costs as high a 23 percent of the total instant costs and as high as 20 percent of total levelized costs.

Table 5: Emission Reduction Credit Costs as a Percentage of Total Cost – Mid Case

ERC as Percentages of Total Cost	ERC as a % of Instant Cost		ERC as a % of LCOE	
	Year = 2013	Year = 2024	Year = 2013	Year = 2024
Generation Turbine 49.9 MW	4.5%	12.3%	3.2%	8.7%
Generation Turbine 100 MW	4.5%	12.4%	3.2%	8.7%
Generation Turbine - Advanced 200 MW	2.3%	6.6%	1.5%	4.0%
Combined Cycle - 2 CTs No Duct Firing 500 MW	3.8%	10.7%	1.2%	3.0%
Combined Cycle - 2 CTs With Duct Firing 550 MW	4.3%	11.9%	1.3%	3.3%
Biomass Fludized Bed Boiler 50 MW	1.4%	4.2%	0.6%	1.8%
Geothermal Flash 30 MW	0.0%	0.0%	0.0%	0.0%

Source: Cost of Generation Model.

Table 6: Greenhouse Gas as a Percentage of Total Cost – Mid Case

GHG as Percentages of Total Cost	GHG as a % of Instant Cost		GHG as a % of LCOE	
	Year = 2013	Year = 2024	Year = 2013	Year = 2024
Generation Turbine 49.9 MW	-0.2%	23.4%	3.5%	5.4%
Generation Turbine 100 MW	-0.2%	23.4%	3.6%	5.4%
Generation Turbine - Advanced 200 MW	-0.1%	20.2%	5.4%	8.3%
Combined Cycle - 2 CTs No Duct Firing 500 MW	-0.2%	22.4%	13.8%	19.5%
Combined Cycle - 2 CTs With Duct Firing 550 MW	-0.2%	23.1%	13.9%	19.5%
Biomass Fludized Bed Boiler 50 MW	-0.1%	19.0%	2.9%	4.7%
Geothermal Flash 30 MW	0.0%	17.6%	7.5%	11.9%

Source: Cost of Generation Model.

Fuel Costs

Fuels for biomass and natural gas-fired power plants are major components of the cost of generation**.** Natural gas for electric generation is purchased primarily from regional market hubs for delivery via the major natural gas pipelines in California. These costs have declined a significant 43 percent on a levelized basis since the *2009 Integrated Energy Policy Report*. These prices reflect the national trends in prices. Biomass fuels are produced through a process similar to a blend of farming and forestry, depending on the specific location and design of the plant. This means that prices for biomass fuels tend to be driven by localized factors and are cheaper than more standard fossil fuels such as oil or natural gas. The price projections found by staff remain nearly unchanged from the *2009 Cost of Generation Report*, and those values are used again in this report.

Transmission and Interconnection Costs

The cost of connecting a new generation project to the electric grid typically falls to the developer. In addition to the cost of the new transmission equipment, there are the costs associated with the electric losses between the generating station and point of interconnection. This report includes both of these costs.

The interconnection voltages are technology- and size-dependent. In contrast, the transmission interconnection lengths are standardized to three lengths (0.5 miles, 1.5 miles, and 5 miles) for the low, mid and high cases, respectively.

Additional Key Insights

Throughout this work, additional key insights that may be of interest to stakeholders and policy makers presented themselves. The insights are as follows:

- The decline of technology costs associated with all solar technologies is expected to continue as manufacturers refine production processes and find low-cost solutions to problems.
- Wind Class 3 and 100 megawatt solar photovoltaic (single axis) technologies with incentives are already cost-competitive with a 500 megawatt combined cycle without duct firing at the developer level.
- While developer costs are near parity of wind and solar technologies versus fossil, this study does not include the additional cost to the utility to support the integration of intermittent resources.
- The success and continued declining costs of nonphotovoltaic solar technologies will depend upon the outcome of external issues and mitigation costs of those technologies.
- In general, wind capacity factors are increasing because of a trend to optimize to lower wind speeds at the expense of peak generation capacity. It is unclear what impact this has on nameplate capacity compared to operational peak capacity.
- Increased quantities of biomass raises questions about long-term procurement of fuel streams. This situation may increase the price of fuel for certain types of biomass generators, while for those with secure fuel streams, like wastewater treatment plants and dairy farms, it may not.
- Long term expectations of low natural gas prices are likely to make gas-fired power technologies, such as combustion turbines and combined cycles, attractive to investors in the near term (the next three to five years). This same trend may challenge the ability of renewable technologies to compete on a cost basis with fossil technologies.
- Despite higher levelized costs, combustion turbine power plants, based on aeroderivative designs, are being built almost exclusively in California instead of combined cycle power plants. Presumably this is due to the operational profiles of combined turbine power plants being better suited to compensate for the variable generation profiles of renewable resources.
- The cost of greenhouse gas emissions credits and emissions reduction credits will likely be a major cost factor in future development of natural gas-fired resources.

CHAPTER 1: Introduction and Overview

Introduction

This report presents the California Energy Commission's estimates of the current and future costs to build and operate new utility-scale [1] (also called *central station*) electric power plants over the next decade. These estimates are developed primarily for use at the Energy Commission to ensure use of common assumptions. These estimates are also used as inputs to multiple studies, including procurement planning studies conducted at the California Public Utilities Commission (CPUC), transmission planning studies conducted at the California Independent System Operator (California ISO), within the Western Electric Coordinating Council (WECC), the California Board of Equalization for property assessments, by the California Air Resources Board (ARB), and a variety of related consulting and academic studies.

In producing these estimates, the Energy Commission recognized that several studies already document the current and/or projected costs of new generation. However, these studies suffer from a number of drawbacks given a California policy maker's perspective. First, the majority of the most thorough and well-researched studies present national cost averages rather than California-specific values. California typically experiences higher costs for new generation than the national average. Second, those studies that produce California-specific cost estimates are usually focused on a single class of generation (such as wind or solar) and ignore other resources that might be considered part of California's future portfolio. In addition, the cost estimates in the various studies are not always directly comparable, as some cost components and other assumptions may be included in one study but excluded in others.

This report seeks to address these issues without unnecessarily replicating high-quality studies. Using a combination of national and California-specific estimates of the current and future costs of new utility-scale generation, this report assesses these studies and translates them into California-specific values. This approach has the added benefit of drawing on a wide variety of resources that can illuminate alternative views of the future trends associated with different technology costs. This report also uses new data drawn directly from surveys of natural gas-fired power plant owners in California to add relevant information. Finally, this report brings a harmonizing perspective to the multiple sources and imposes a consistent set of assumptions that allow for direct comparisons that would not otherwise be possible between disparate studies.

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1 For this report, utility-scale is considered to be project 20 MW or larger.

The cost to build and operate a new power plant in California depends on which technology is built, where in California it is located, how much it costs to finance the project (typically a function of who owns it), and how much the plant runs. The amount of energy a power plant produces over its lifetime can depend on either its cost to operate relative to other power plants (such as for fossil-fueled generators who must participate in a competitive market) or the availability of the energy source (such as for renewable generators).

The authors have also limited the scope of this report to estimating the costs to the developer rather than to the utility or ratepayer. This is important for two reasons. First, the electric grid is a large and dynamic system. Adding a resource at one location may require the utility to alter how it operates the surrounding grid, thus changing the economics of projects already in place. Estimating those effects would be necessary to estimate the total cost to the utility and would require significant additional analysis that is beyond the current limitations of time and resources within the Energy Commission. Second, the value to the developer of a power plant is the stream of payments it will receive from its operation. By limiting the scope of this analysis to the developer, it is possible to estimate the level of payment necessary to achieve a reasonable rate of return and, thus, the value to the developer. Any attempt to estimate value to the utility or to the state would require a dramatic expansion of the assumptions about the size of those values and the ability of the utility or ratepayer to capture those values. Estimates of values to utilities or ratepayers such as environmental benefits, economic or jobs benefits, or grid reliability benefits are beyond the scope of this project.

This report considers three financing options (merchant, investor-owned utility, and publicly owned utility), presents a deterministic mid case, probabilistic high and low cases, and analyzes a variety of utility-scale technologies including:

- Solar photovoltaic.
- Solar thermal.
- Wind.
- Geothermal.
- Biomass.
- Natural gas-fired.

Study Perspective

In estimating the costs of building and operating a new utility-scale power plant in California, many assumptions must be made to calculate those costs over a plant lifetime that can span 20 or more years. It is effectively impossible to accurately predict all the factors necessary to estimate lifetime costs of a new power plant that might not even be built for another decade. As a result, this study has adopted the principle of transparency over certainty. This means that rather than make any claim of certainty regarding these values, this report—along with the calculator that was built to support these calculations, known as the Cost of Generation Model (COG Model)—uses a range of plausible inputs to create scenarios that include transparent input values.

In addition to developing and presenting a range of values, this report also translates those transparent input values into an understandable set of metrics. The key output metrics are *instant cost, installed cost,* and *levelized cost*.

- *Instant cost is the cost to* build a power plant if it could be built overnight, sometime characterized as overnight cost. It includes cost of all equipment, permitting, and the construction - all the costs except for the financing of the construction.
- *Installed cost* is the instant costs plus the construction loan including development fees.
- *Levelized cost* reflects the lifetime cost of operations and maintenance combined with the installed cost expressed as a constant stream of costs per unit of value over the lifetime of the plant. It is most commonly measured in dollars per megawatt-hour ($/MWh), but sometimes reported at dollars per kilowatt-year ($/kW-Year).

Levelized cost is not simply the sum of the annual cost divided by the total energy produced by the plant because costs can fluctuate from year to year. As a result, future costs must be translated into present values. The *present value* of a future year dollar cost is defined as the amount of present day dollars that, when paid a fixed interest rate (typically referred to as the *discount rate*) over the intervening years, would produce the same number of nominal dollars in that future year.

The first step in calculating levelized cost is to estimate each year's cost. All future costs are then discounted by a discount rate that reflects the willingness of investors to take on these future obligations. Finally, these costs are divided by the expected generation over the lifetime of the plant to produce a number that reflects the cost per MWh in constant terms over the long life of the plant and that can be compared to other projects competing for the same investment dollars.

The cost of any new power plant is a result of numerous, sometimes intertwined factors relating to changing market conditions, labor and resource costs, regulatory issues, and local factors such as real estate market forces and air, water, and land-use planning. A project developer will be presented with a unique combination of these costs depending on precisely where, when, and how the project is put in place. There is no way to anticipate all of these factors for every new generation resource built in California. This report deals with this issue by developing three cost scenarios.

Staff constructed a mid-cost case using the best current estimate for costs that are applicable across the state for all factors involved in estimated the future costs of new generation. This case reflects median values for factors such as emissions credit prices and, therefore, will not be representative of any single project, but rather the portfolio of projects as a whole.[2] Around the mid-cost case a high-cost and a low-cost case were constructed using the simultaneous highest cost and lowest cost factors. This provides a bracket of costs that represents how any project under the most favorable (or unfavorable) conditions might fare. These cases are referred to as mid case, high case, and low case for the remainder of the report.

Finally, within these cost cases a more narrow range of more likely cost values was constructed using the Analytica software tool. This probabilistic range of values provides a narrower estimate of cost ranges than are likely to be seen in the marketplace. These probabilistic high, low, and mid cases are presented in the chapter on levelized costs.

Background of Report

The first COG report and supporting COG Model date back to the *2003 Integrated Energy Policy Report* (*2003 IEPR*). Assumptions were based on best available data, and levelized costs were calculated as single spreadsheet or calculations for each technology.

The subsequent effort for the *2007 Integrated Energy Policy Report* (*2007 IEPR)* significantly improved the accuracy of the data by surveying power plant developers. A model was developed to calculate levelized costs for all technologies and for all three classes of developers: merchant, investor-owned utility (IOU), and publicly owned utility (POU).

The *2009 Integrated Energy Policy Report* (*2009 IEPR)* made further improvements in modeling and provided high and low cost assumptions in addition to the traditional mid cost value. The present *2013 Integrated Energy Policy Report* (*2013 IEPR)* effort is further improved through additional data surveys and replacement of the *2009 IEPR* levelized cost estimates with ranges based on probability distributions.

Changes From Draft Report

Numerous changes were made to the draft report in response to public comments. A summary of the comments are in Appendix F. Major revisions were made in solar

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2 *Mid case* has no universal definition. The Energy Commission mid cases are based on simple averages, where sufficient data are available. In cases where very limited cost data are available, the mid cases are based on an assessment of the cost that is most likely to occur—this is necessarily somewhat subjective and can perhaps be best described as a sort of nominal value.

photovoltaic (PV) and wind estimates, while minor revisions were made to:

- Update land costs.
- Update interconnection costs and loss factors.
- Update plant-side losses.
- Update capacity factors (CFs).
- Update interconnection losses and costs.
- Remove double-counting of sales tax.
- Add more specificity to reported costs of interconnection, land, and licensing.

Further, levelized costs are now reported at the interconnection point, not the load center.

Revisions to solar PV and wind estimates are mostly due to updates in instant costs and CFs. They are also partly due to updates in operations and maintenance, transmission, and land costs. The reassessment of land costs, correction of sales tax, and the continued declining costs of solar and wind have all lowered the capital cost estimates.

Capital cost estimates of all technologies are generally lower than in the draft report due to reassessment of land costs and correction of sales tax.

Comparison to *2009 Integrated Energy Policy Report* Assumptions

Table 7 compares the key current assumptions to the comparable *2009 IEPR* assumptions. Notable changes include the following:

- Fuel costs for natural gas units have dropped dramatically—43 percent on a levelized cost basis. This decrease reflects the shift in the natural gas markets toward domestic gas resources from shale formations that have driven gas costs to near-record lows and are expected to have downward pressure on prices over the study horizon.
- Advanced combustion turbine (CT) costs have increased significantly—mostly due to having more data to analyze.
- All nonsolar renewable technologies have higher capital costs than reported in 2009, with geothermal flash being dramatically higher. This is driven by the availability of data from actual projects that were not available in 2009. The expected costs of these projects seem to have been underestimated compared to the actual costs encountered, as this technology undergoes its first major domestic investment surge in more than 15 years.
- Solar technologies have slightly lower capital costs when compared against projects of the same size (20 MW [megawatts]) but significantly lower costs when comparing against the current larger projects (100 MW). The increased size has the largest effect on instant costs, mostly because the transmission costs can be spread over a larger gross capacity.

Operations and maintenance (O&M) costs for most renewable technologies are significantly higher than reported in 2009, but the single-axis solar PV technology O&M costs have dropped significantly. This reflects better data for all technologies, as well as improved dissemination of O&M best practices in a rapidly maturing PV marketplace.

Table 7: Comparison of Current Assumptions to *2009 IEPR* Assumptions

Technology	Capacity Factor (%)			Instant Cost ($/kW)			Merchant* Installed Cost ($/kW)			Total O&M ($/kW-Year)			Levelized Fuel Cost ($/MMBtu)		
Year = 2013 (Nominal $)	2009 IEPR	2013 IEPR	% Change	2009 IEPR	2013 IEPR	% Change	2009 IEPR	2013 IEPR	% Change	2009 IEPR	2013 IEPR	% Change	2009 IEPR	2013 IEPR	% Change
Small Simple Cycle	5.00%	5.00%	0%	1373	1224	-11%	1459	1310	-10%	27.84	28.39	2%	11.74	6.67	-43%
Conventional Simple Cycle	5.00%	5.00%	0%	1309	1220	-7%	1412	1305	-8%	20.8	27.44	32%	11.74	6.67	-43%
Advanced Simple Cycle	10.00%	7.50%	-25%	879	987	12%	1142	1069	-6%	21.2	25.24	19%	11.74	6.67	-43%
Conventional Combined Cycle (CC)	75.00%	57.00%	-24%	1162	1000	-14%	1168	1088	-7%	30.5	37.62	23%	11.74	6.67	-43%
Conventional CC Duct-Fired	70.00%	57.00%	-19%	1146	981	-14%	1145	1068	-7%	28.74	37.62	31%	11.74	6.67	-43%
Biomass (Direct Combustion W/ Fluidized Bed)	85.00%	80.70%	-5%	3458	4498	30%	3938	5068	29%	143.82	143.63	0%	2.47	2.61	6%
Geothermal Binary	90.00%	85.00%	-6%	4225	5342	26%	5070	6743	33%	79.78	89.79	13%	N/A	N/A	N/A
Geothermal Dual Flash	94.00%	85.00%	-10%	3863	6039	56%	4636	7382	59%	96.09	89.79	-7%	N/A	N/A	N/A
Solar Thermal Parabolic Trough	27.00%	26.50%	-2%	3199	3819	19%	3599	4259	18%	73.78	70.95	-4%	N/A	N/A	N/A
Solar Photovoltaic (Single Axis) 20 MW	27.00%	26.60%	-1%	3940	3985	1%	4432	4267	-4%	73.78	29.60	-60%	N/A	N/A	N/A
Solar Photovoltaic (Single Axis) 100 MW	N/A	26.60%	N/A	N/A	3660	N/A	3242	3918	N/A	N/A	29.60	N/A	N/A	N/A	N/A
Wind Class 3	37.00%	42.00%	14%	2072	1911	-8%	2338	2074	-11%	32.61	21.67	-34%	N/A	N/A	N/A

* Installed cost is for merchant case only. IOU and POU not shown. All other costs apply to all three cases.

Source: Energy Commission.

Report Overview

Chapter 2 provides the financing assumptions and method for developing those assumptions. It provides the cost of capital assumptions by developer and technology for the three cost cases, mid, high, and low. It provides debt service recovery ratios (DSCR) by developer for the three cost cases. It summarizes the tax incentives for each technology, as well as the state and federal tax rates.

Chapter 3 provides the fuel, emissions, and transmission assumptions. It provides the fuel prices by technology for each of the three cost cases, including the method of how these cost cases were developed. It delineates the transmission line losses, California ISO charges, and emission factors.

Chapters 4–9 provide the technology-specific assumptions for the three cost cases. Each chapter delineates the plant costs (instant and installed by developer, O&M, insurance, and ad valorem) and plant characteristics (site losses, CFs, heat rates, and capacity degradation factors).

Chapter 10 provides the levelized cost in dollars per megawatt-hour ($/MWh), including total and component costs. Levelized costs are provided for mid, high, and low cases as both deterministic and probabilistic values.

Chapter 11 discusses key insights as well as areas for further investigation and study in future Energy Commission work regarding generation costs.

Appendix A provides graphical summaries of the relative effects of the various tax benefits on levelized cost. It also provides graphs showing the effect over the 2013 to 2024 time horizon.

Appendix B summarizes the natural gas technology assumptions prepared by Aspen.

Appendix C provides tornado diagrams for all the subject technologies—a diagram that shows the relative effect of key assumptions on levelized cost.

Appendix D provides a description of the models used. The COG Model is the Energy Commission's model that has been used in past *IEPR*s to develop the necessary levelized costs. Analytica is a probabilistic model owned by Lumina. The Analytica Cost of Generation Analysis Tool (ACAT) is a melding of the COG and Analytica to provide probabilistic high and low levelized costs.

Appendix E provides the mid case component levelized costs for each developer in $/MWh and $/kW-year.

Appendix F discusses comments from stakeholders and how staff used this input to make revisions from the draft to the final version of this report.

CHAPTER 2: Financing Costs and Tax Treatment

Background

Financing and debt costs associated with the construction and ownership of a power project have an important effect on the total cost of energy from a project. This report focuses on *merchant*-developed (not utility-owned) power projects because private owners are by far the dominant developers in the market. In addition, merchant projects generally are financed on a project-by-project basis, meaning that two projects developed by the same firm may have different financing terms. In contrast, almost all IOU projects are financed from the central corporate treasury, so the terms do not vary by project. Projects developed by POUs usually are bond–financed, and those bond rates are more closely tied to the rating for the POU than to the project characteristics. As a result, merchant financing is more complex and variable and requires more explanation.

The current environment for financing independent power projects is challenging. These challenges include weak corporate profits, changes in corporate direction, and heightened risk aversion. As a result, a number of the financial institutions that were lead underwriters in the past are either pulling out of the market or are taking a lower profile in project financing.

Another factor affecting the market for financing power projects is the differentiation of roles that various players are willing to play. These roles are, to a large extent, driven by the risk profiles of the institutions. Two examples demonstrate this differentiation:

- Some financial institutions are unwilling to lend during the construction phase because of the potentially greater risk of project failure during the early portion of the project. On the other hand, once the project has become operational and demonstrated the ability to meet its performance requirements, these same institutions are willing to provide relatively low-cost financing.
- Some financial institutions are realizing that providing relatively long-term, fixed-priced financing places their institutions at risk relative to their cost of funds. As a result, these institutions are willing to finance only with a relatively short debt term (for example, seven years) regardless of the duration of the power purchase agreement (PPA) of a project. At the same time, other institutions have a willingness to commit to longer-term obligations because their sources of funds have a much longer time horizon (for example, insurance companies). Thus, some projects are financed with, in effect, a balloon payment after a relatively short term with the expectation that the project will refinance once it has established a solid operating history.

A new challenge facing certain projects is difficulty in obtaining “tax equity” financing. Under tax equity financing, small renewable generation owners who have insufficient income to use the full value of a tax benefit can sell the tax benefit to third parties who are eligible to claim it under current tax laws. Some of the key players providing tax equity during the period from about 2003 to 2008 are no longer in the market.[3] New players with an interest in tax equity have come on the scene (for example, affiliates of IOUs), but these newer, less traditional financing entities have proven to make the financial closing process much slower. (The tax equity market is discussed in more detail below.)

Finally, it is important to understand that the ultimate financing package of each power project is unique. The project sponsor(s), the markets, the PPA terms and conditions, and the technology necessarily vary from project to project. While financial institutions attempt to use knowledge and experience gained from previous project financings, the uniqueness of power projects ultimately requires financing institutions to craft an individualized financing package that meets the needs of all participants.

Key Terms

There are several interrelated factors that ultimately affect the financing of independent power projects. This section defines these factors and explains these interactions.

- Interest Rate: The key factor that quantifies the risk that the lender perceives in a power project is the interest rate. Interest rate is often measured as a spread above an index, such as the London Interbank Overnight Rate (LIBOR). The spread above LIBOR is used to compensate the lender for the perceived risk of lending on the project. (There is a more detailed discussion later in this chapter on the LIBOR and how it is incorporated into the COG Model.)
- Leverage: The amount of leverage is defined as the ratio of debt issued relative to the total cost of the project (where the total cost of the project is defined as the sum of both debt and equity). Because cash flow is always allocated to make debt service (that is, interest and principal) before payments to equity investors, the greater the leverage, the greater the risk that cash flow will be inadequate to meet debt service.
- Debt Service Coverage Ratio (DSCR): The DSCR is equal to the ratio of expected cash flow to debt service. As the amount of debt on a project increases (or the cost of the debt increases), the DSCR decreases. On a forecast basis, lenders typically look at both the average and minimum DSCRs. For projects with relatively certain CFs (for example, a base load geothermal or biomass project) or with relatively certain net revenues (for

3 Lehman Brothers was an important participant that no longer exists. Another possibility for the loss of participants is that those entities have less interest as a result of the worldwide recession reducing corporate profitability.

example, a natural gas-fired project with a tolling agreement), often the average and minimum DSCR targets are similar. However, for projects with uncertain energy sources (for example, wind or solar projects), the average and minimum DSCRs can differ based on the relative likelihood of energy production. In other words, the minimum DSCR would be based on a worst-case wind or solar forecast (the so-called "P99" forecast), while the average DSCR is forecast based on an expected wind or solar forecast (the "P50" forecast).[4] "P99" is the wind/solar forecast that has a 99 percent probability of being exceeded, while a "P50" forecast has a 50 percent probability of being exceeded. (Lowder, 2011).

- Term of Debt: Lenders view longer-term debt as being at greater risk for repayment than shorter-term debt. There is a greater chance of unexpected problems cropping up over a longer term that could threaten the ability of a project to repay debt obligations or that could make the loan uneconomic. Also, because so few lenders are willing to provide very long-term financing, lenders that do so have few other entities to which they can sell down their positions if the lender wants to liquidate its position. Thus, even when a project has a long-term PPA, lenders will loan money with debt term (or "tenor") that is shorter than the term of the PPA. However, a project is likely to have a sequence of debt instruments that will extend close to the full term of the project life. The project will refinance at the end of the term of the first debt instrument, often with a balloon payment. In these cases, the initial debt instruments may have interest-only payments that reduce the annual debt burden and make the DSCR acceptable.
- Quality of Developer/Sponsor: Lenders evaluate the quality of the power project developer/sponsor in determining financing costs. A major player with significant experience with a particular technology and market will generally receive the most favorable financing terms. These developers must be considered "investment grade," and the lending is at the project level, not the holding company level.
- Term of PPA: While there are certain lenders that are willing to accept the risk of merchant financing, most financial institutions want to have a greater level of certainty associated with the revenue stream for the project. The financial institutions obtain this greater certainty by requiring the project to have a PPA with a term that is longer than the term of the debt.
- Technology/Fuel Source: Lenders consider the technology or fuel source when pricing their debt. Technologies with greater perceived risk in fuel source or plant operating costs (for example, geothermal and biomass) will typically have higher debt costs.
- Incentives: The financing approach for power projects can depend greatly on the types of incentives available to sponsors of the projects. Incentives such as production tax credits, cash grants, or investment tax credits can have an effect on both the leverage of a

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4 The "P99" forecast is the wind/solar forecast that has a 99 percent probability of being exceeded, while a "P50" forecast has a 50 percent probability of being exceeded. (Lowder, 2011).

project and the types of entities that will participate in the financing. For example, if a solar project is eligible for a cash grant, there will be less need for tax equity in the project.

- Size of Project: The size of the project and the financing requirements will also have an effect on the financing terms being offered to a project sponsor. Large projects present greater risk to a financial institution, as a result, lenders will impose a higher cost of debt on the project than a smaller project using similar technology located in the same market.

Analytic Method for Estimating Financing Terms

The financial structure and base parameters for investor-owned and merchant plant developers are taken from the Board of Equalization's (BOE) *2012 Capitalization Rate Study* (Gau and Thompson, 2012) and adjusted to match December 2012 financial market conditions. This source was chosen because it was developed by another state agency using a public review process. These rates are consistent with the allowed rates of return set by the CPUC for the three large IOUs (CPUC Decision 12-12-034). Debt costs for all three owner types were derived using public sources available as of December 2012. Derivation of the merchant debt rate is discussed in detail below. The IOU debt rate is taken from the CPUC decision. For POUs, the debt rate is based on public sources for highly rated issuances for 30-year notes (Bond Market Yields, 2012; Composite Bond Rates, 2012).

The appropriate discount rates are based on the after-tax weighted average cost of capital (WACC). The allowance for funds used during construction (AFUDC) rates is based on WACC for IOUs and on the cost of debt for merchant plants and POUs. The WACC is calculated by multiplying the shares from equity and debt sources by the after-tax rate of return for equity[5] and the cost of debt (or interest rate), respectively. For example, assume a project is financed with 40 percent equity and 60 percent debt, and the rate of return for equity is 10 percent and the debt interest rate is 5 percent. Because debt interest is tax-deductible, the debt rate must be adjusted; in this case with a 40 percent corporate tax rate, the after-tax interest rate is 3 percent. In this example, the WACC equals (40 percent x 10 percent) plus (60 percent x 3 percent), or 5.8 percent.

To characterize financing for merchant plants in more detail, the Energy Commission contracted with MRW Consulting (MRW). MRW used a two-part approach to assess the finance market for merchant developers. This information was used to supplement the finance structure and assumptions in the BOE's *Capitalization Rate Study*. First, MRW researched the current assumptions being used by financial institutions to finance the

5 For IOUs, a weighted average mix of common and preferred stock rate of return was calculated to simplify the model equation.

construction of new independent power projects. MRW conducted an informal survey of several financial institutions to solicit their views regarding financing trends in the energy market.[6] Based on survey responses, MRW developed ranges of key financial attributes, differentiating financing trends by fuel type (for example, natural gas, solar, wind, biomass, and geothermal) when possible. While MRW indicated to the financial institutions that the focus was on the California market, the questionnaire did not differentiate between California and other regions.

Second, MRW reviewed several recent studies and attended a webinar that provided some data on financing trends for renewable power projects. MRW also reviewed the publicly available PPAs executed between the California IOUs and developers of renewable energy projects. Its findings are presented in the next section.

Merchant Owners and Developers

Tax Equity Financing and Yields

Many renewable energy projects rely to some degree on the tax equity market for financing. As was noted earlier, the supply of tax equity for renewable energy projects declined substantially during the recent economic downturn. Lower corporate profits meant traditional tax equity providers could not absorb the same level of tax benefits. New entrants in the tax equity market face the significant challenges of understanding and evaluating the array of renewable energy technologies, project structures, and contract and market risks.[7]

Tax equity can be a more expensive form of financing than other sources of capital, such as debt, for several reasons. First, the tax equity market is not very transparent, nor is it highly liquid. In addition, each project is unique, with unique developers and investors. This uniqueness increases the transaction costs of using tax equity for financing. Investors are generally earning yields from 7 percent to 9 percent (*State of the Tax Equity Market,* 2012; Mendelshohn and Harper, 2012).

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6 MRW contacted 10 financial institutions and received responses from 5 of them. The financial institutions providing information for this project are all active in project financing. They are geographically diverse (that is, they are based in Europe, Asia, the United States, and Australia). A number of the financial institutions were very concerned about confidentiality and agreed to participate only on the condition that their identities would be masked. Thus, in the information presented here, MRW has masked the identities of the financial institutions.

7 One estimate puts the number of active players in the tax equity market at about 20 to 22 entities (*State of the Tax Equity Market*, 2012).

The choice of tax equity financing varies with the type of tax credit that is applicable and most beneficial to a project (Miller and Mulcahy, 2011). When a production tax credit (PTC) is the preferred instrument, as is usually the case with wind, a partnership "flip" is used. The tax equity investor takes 99 percent ownership to the end of the PTC (10 years), and then ownership flips to the developer, who owns 95 percent to the end of the project. For projects using the investment tax credit, largely for solar, a sale/leaseback is most common. The tax equity investor leases the project for less than 80 percent of the project life and provides more than 20 percent of the equity contribution (plus nonrecourse debt).

London Interbank Overnight Rate and the Cost of Generation Model

Renewable power project debt financing is often priced using the LIBOR plus a premium. LIBOR is a daily rate that sets the borrowing costs for financing institutions; it is considered the benchmark for short-term interest rates across the financial system.

Because LIBOR can vary daily, project owners with debt financing linked to LIBOR typically choose to convert the variable rate into a fixed rate. To accomplish this, the project owners use a LIBOR swap, which provides the project with a fixed interest rate over the term of the debt. For modeling renewable project costs based on a cost of debt input, LIBOR swap rates represent a useful market view of LIBOR over a medium to long term period. For these reasons, the COG Model now uses a "LIBOR + premium" approach for determining the cost of debt for merchant/independent power producer (IPP) renewable projects.

This approach applies LIBOR swap rates tied to the debt term in the model, with a risk adder applied on top of that (for example, a project with a 10-year debt term would use a 10-year LIBOR swap rate). In practice, this is similar to the previous approach of the COG Model to using bond rates (an approach consistent with the *BOE Capitalization Rate Study*). Using the "LIBOR + premium" approach, however, better reflects the actual debt financing terms provided to renewable project developers.

Finally, project interest rates often include both a base spread over LIBOR plus periodic "step-ups" in the spread. For example, the step-ups might increase the base spread by 25 basis points every four years.

To account for the LIBOR swaps and the step-ups, an annualized spread over LIBOR is calculated. This annualized spread should result in the same net present value of debt costs as would be found if there was a time-varying spread. The Wall Street Journal Markets Data Center provides a reliable, public source for LIBOR swap rates for various lengths of loans, known as the *debt tenor*.[8]

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8 The three-month LIBOR rate is the most commonly used benchmark rate. However, other LIBOR rates do exist, including one-month, six-month, and one-year rates.

Results for Merchant Developers Terms

Based on the approach and assumptions outlined above, MRW identified the following ranges for financing parameters, as well as more qualitative information about the financing trends for power projects. This section presents both quantitative and qualitative findings.

Quantitative Results

Table 8 summarizes the quantitative financing factors collected. This table presents the average of the minimum and maximum values for four key financing terms: average and minimum DSCRs, pricing over LIBOR (that is, the cost of debt), and tenor.

Table 8: Merchant Developers' Financial Parameters

Technology and Case	Premium Over LIBOR Rate	DSCR (Average)	DSCR (Minimum)	Tenor (Years)
Mid Case				
Gas-Fired Technologies	2.85%	1.37	1.37	10
Biomass Technologies	3.90%	1.72	1.72	20
Geothermal Technologies	3.90%	1.79	1.79	20
Solar Technologies	3.50%	1.35	1.27	20
Wind Technologies	3.50%	1.35	1.27	20
High Case				
Gas-Fired Technologies	3.10%	1.39	1.39	7
Biomass Technologies	3.17%	1.78	1.78	15
Geothermal Technologies	3.17%	1.88	1.88	15
Solar Technologies	2.90%	1.45	1.30	15
Wind Technologies	2.90%	1.45	1.30	15
Low Case				
Gas-Fired Technologies	2.60%	1.35	1.35	20
Biomass Technologies	3.08%	1.65	1.65	25
Geothermal Technologies	3.08%	1.70	1.70	25
Solar Technologies	2.55%	1.24	1.24	25
Wind Technologies	2.55%	1.24	1.24	25

Source: MRW 2012.

The following observations are drawn from **Table 8**:

- Biomass and geothermal projects are considered riskier than natural gas, solar, and wind projects. This is seen in the lower leverage, higher pricing, and higher DSCRs than for the other generating technologies. The higher level of project risk for biomass and geothermal projects is partly attributed to the technology and fuel sources. Solid fuel power plants require more project infrastructure than do other fuel types. Biomass projects often have a wide range of fuel sources without long-term fuel supply agreements or liquid fuel markets, while geothermal projects have inherently uncertain steam supplies as have been seen at the Geysers. Some of the risk also is based on the relatively small number of these projects being developed.

- Pricing for natural gas projects is slightly higher than for wind or solar projects. Part of this may be due to the somewhat larger size of natural gas projects than typical wind or solar projects.
- Tenors are somewhat longer for wind and solar projects than for natural gas projects. This is not surprising given that PPAs for natural gas-fired projects are often shorter than for renewable projects. However, according to one lender, the tenor for debt for renewable projects has decreased significantly over the past two to three years as lenders face greater pressure on their balance sheets and find more difficulty rationalizing 15- to 20-year tenors for financings. Another lender said that certain lenders are willing to issue longer-term debt (for example, duration of the PPA minus two years). This has also led to hybrid project structures, where banks will finance construction and the first few years of operation, after which the financing will be taken over by institutional investors with much longer financing capabilities (for example, insurance companies).
- DSCRs for natural gas projects are somewhat higher than for wind or solar projects. Also, lenders do not tend to distinguish between minimum and average DSCRs under base case conditions. However, as discussed above, the one-year minimum DSCR for wind or solar projects is typically set at 1.0 for the P99 forecast.
- Leverage is quite similar for natural gas, solar, and wind projects.

One important point is that the parameters described for the debt instruments are not consistent with full long-term financing for most renewable projects. The terms are typically very short-term, for example, less than one-third of the expected life, and the payments are often interest-only with large balloon payments. These balloon payments imply that a second financing will be required, but there is no information on those terms. Because the COG Model looks over the entire life of the project, the model uses terms based on project bond financing, despite that type of financing being fairly rare. The average costs of the different financing mechanisms should be relatively similar so as to minimize the arbitrage opportunities.

Qualitative Results

Aside from the quantitative financing trends presented above, the financial institutions that responded to MRW's request for information provided valuable insights into other issues of importance regarding project financing. These issues are summarized as follows:

- Merchant Risk: Immediately after the meltdown of the merchant generation market in 2002 – 2005, lenders were unwilling to lend to merchant projects that did not have a solid PPA with a creditworthy counterparty. However, as time has passed, lenders have reassessed the risks associated with accepting merchant projects. There are at least two forms of merchant risk that lenders might accept under certain circumstances. First, a small subset of lenders is willing to accept "merchant tail" risk, which is where the tenor of the debt exceeds the duration of the PPA of the project. Banks are not typically willing to accept this type of risk; institutional investors are more willing to do so. Also, lenders are willing to accept only a limited amount of such debt (for example, $50/kilowatt [kW] to $100/kW) and require a good "story" regarding the ability of the project to obtain capacity payments after the end of the initial PPA. One lender noted that there are lenders willing to lend higher amounts on a merchant basis (for example, up to $200/kW) in the "Term Loan B" market, which is a high-yield loan. Second, some lenders will lend on projects in which the entire capacity of the project is not contracted, but the project sponsor has a good plan for marketing power from the project.

- Technology Risk: Lenders need to be concerned about the long-term viability of the technology of a project. Vendors of natural gas-fired generation technology (for example, General Electric [GE], Siemens, and Mitsubishi) have significant balance sheets to ensure performance in case of significant warranty claims even for new generation. For example, when GE introduced the Frame 7F combustion turbine, there were numerous problems that GE had to resolve under warranty. (Tenaska Georgia Partners LP, 2000). However, some lenders are concerned about the ability of certain vendors to meet warranty claims. One stated:

  > In the solar space, most of the module suppliers are very weak financially, so we are now requiring completion guarantees in a form of Contingent Equity from the Sponsors and also Warranty Reserve Letters of Credit for the duration of the project: 10 percent of the module supply cost for the years 1 – 5, and 1 percent for the years 6 – 20 assuming the performance test is passed at the end of year 5.

- Continuation of PTCs: Lenders have mixed feelings about the future of these tax credits, with some believing that they will continue to be available, but others expecting that if they continue, they could be reduced in size.
- Loan Tenors: As discussed previously, lenders are issuing loans of different tenors. A financial institution's country of origin apparently is a key driver in determining a bank's preference for the term of debt. For example, the Japanese banks issue the longest-term debt with terms as long as the PPA minus two years, while Canadian banks issue the shortest-term debt (for example, 10 years or less).
- Changing Regulations for Banks: Lenders note that changes in banking regulations will likely have an increasing effect on the banks' flexibility in structuring financing in the future. This tightening regulation resulted from the financial meltdown in 2007 – 2009.

Comparison to Other Studies

MRW identified the following studies as providing reliable, recent data on renewable power project financing trends:

- *Renewable Energy Finance Tracking Initiative Solar Trend Analysis* (Hubbell, et al., 2012)
- *Renewable Energy Project Finance in the United States: 2010 – 2013 Overview and Future Outlook* (Mintz et al., 2012).

The National Renewable Energy Laboratory (NREL) report presents financing trends only for solar PV and concentrated solar power (CSP) projects that had closed financing but were not yet on-line at the time data were collected. In addition, the NREL report disaggregates, or breaks down, the data by project size, with one category for projects less than 1 MW and one category for projects greater than 1 MW. NREL researchers collected the data over the period from the fourth quarter of 2009 to the second half of 2011.

The Mintz report addresses financing trends for utility-scale renewable power projects, including wind, CSP, solar PV, geothermal, and biomass projects (Mintz et al., 2012).

Table 9 summarizes the quantitative financing factors presented in the two reports reviewed by MRW for this report.

Table 9: Summary of Merchant-Owned Financial Parameters From Other Studies

	NREL Report	Mintz Report
PPA Term	15-20 years, weighted average	N/A
1st Year PPA Price	$0.079 per kWh (for CSP only)	N/A
Escalation Rate	1.6% (for CSP only)	N/A
Percentage of Debt	Variable	N/A
Cost of Debt	Trending down over time, from high of 8.8% to about 6%	5.5% to 10% (fixed) Lowest for wind and highest for CSP Floating debt rates ranged from LIBOR + 175 basis points to LIBOR + 325 basis points
Term of Debt	18 years (solar PV) 12.1 years (CSP)	Varies by technology and project participants; tenors have started to lengthen in recent years
Debt Service Coverage Ratio	1.3	N/A
Return on Tax Equity	Approximately 14% (solar PV)	

Source: MRW.

These reports also present qualitative information on financing trends that is worth considering. Key points made in the two reports are summarized below:

- PPA Term. The NREL study noted that the length of PPAs for large-scale solar projects mostly declined over the study period but then rose in the second half of 2011.
- Cost of Debt: NREL identified a reduction in the cost of debt for large-scale PV projects. NREL's numbers (6 percent to 8.8 percent) are similar to the cost of debt reported by Mintz. In its report, NREL reported pricing for fixed debt of 7 percent to 8 percent for solar PV and 7.5 percent to 10 percent for CSP. The cost of debt was least expensive for wind projects, ranging from 5.75 percent to 7.25 percent. The reduction in the cost of debt may reflect an increased use of federal cash grants and loan guarantees in the past few years (Mintz et al., 2012).
- Term of Debt:[9] As was noted previously, banks are not as willing to provide long tenors for financing. Institutional investors that are looking to invest funds are willing to provide long-term financing. This divergence in preference by investor-type has led to new, hybrid financing structures. In the past European banks would offer long-term financing, but the crisis in the European markets and new regulations[10] have significantly curtailed these banks' ability to participate in the market.

Review of Power Purchase Agreements

The CPUC provides a spreadsheet that presents the current status of all renewable power projects under development or operating that the IOUs use for Renewables Portfolio Standard (RPS) compliance.[11] This spreadsheet provides a great deal of information, such as project capacity (in MW), expected generation, technology, PPA term, and operational status. For certain RPS projects, the spreadsheet provides links to the PPA of the projects.[12]

MRW reviewed the publicly available PPAs for 39 projects for energy price data and escalation factors. The energy prices included in the publicly available PPAs ranged from $40.20/MWh to $139.00/MWh.

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9 A recent white paper by Bloomberg New Energy Finance provides a matrix showing the characteristics of potential investors, including investors' time horizon and targeted returns. (Reznick Group, 2012,
p. 12).

10 The Basel III regulations may hamper future participation by European banks. The Basel III regulations "require that any loans longer than one year be backed by funding of at least one year." (Reznick Group, 2012, p. 14).

11 RPS_Project_Status_Table, see <http://www.cpuc.ca.gov/NR/rdonlyres/054D164B-9DE5-4631-9F05-9CB4C3745B7B/0/RPS_Project_Status_Table_2012_Sept_Final.xls>.

12 The PPAs for RPS projects are confidential for a specified period and then are made public.

There was only one PPA with a solar project, and this project had the highest power price ($139/MWh). PPA prices for small hydro were the next most expensive ($93.83/MWh). Wind purchase prices ranged from $49.00/MWh to $96.81/MWh, and biomass prices varied from $40.20/MWh to $81.00/MWh. There was only one geothermal PPA with a publicly available price ($80.02/MWh).

Most of the PPAs reviewed did not have price terms that allowed escalation at a fixed rate. Of the 39 PPAs studied, only 2 contained an explicit escalation factor: 2 percent for a wind plant and 1 percent for a geothermal plant. Six contracts had escalation factor ranges. The structure of these escalation factors was quite diverse:

- A "collar" (that is, the escalation rate was bounded in a specific range)
- A "CPI +" escalator, where the escalation rate equaled the Consumer Price Index (CPI) plus a fixed adder
- A percentage of the CPI with a not to exceed escalation factor

Most commonly, the PPAs provided a table with specific annual energy prices for 5 to 10 years in to the future but did not provide a specific escalation factor.

Tax Benefits and Treatments

General 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 type of owner. 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 10**.

Table 10: 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 (or property) tax differs depending on the developer:

- The merchant-owned facility tax is based on the market value assessed by the BOE, 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. An average statewide rate of 1.1 percent is multiplied by the installed cost of the power plant and a property tax depreciation ("percent good") factor from BOE tables.
- The utility-owned plant tax is based on the value assessed by the BOE and is set to the net depreciated book value. An average statewide rate of 1.098 percent is multiplied by the depreciated 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 in the COG Model is assumed to be equal to the calculated property tax for a utility-owned plant.

New solar units receive a lifetime exemption from ad valorem until the exemption expires in 2017. All-solar components of the plants receive a 100 percent exemption, dual-purpose components a 75 percent exemption, and nonsolar components, such as transmission and support buildings, no exemption.

Sales Tax

California sales tax is estimated as 8.4 percent based on the 2013 Legislative Analyst's Office estimate (Taylor, 2013). Sales tax is applied against materials only, not against labor. For the wind units and the solar tower with 11 hours storage, the data were collected as installed costs, which included the sales taxes.

Renewable Energy Tax Credits and Incentives

Table 11 summarizes the Energy Tax Credits and Tax Incentives:

- Business Energy Investment Tax Credits (ITC)[13]
- Renewable Electricity Production Tax Credits (PTC)[14]

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13 Dsire website: see
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=0.

14 Dsire website: see
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1.

- Renewable Energy Production Incentive (REPI)
- Accelerated Depreciation

Business Energy Investment Tax Credits

The business energy ITCs were authorized under the 2005 and 2008 federal Energy Policy Acts (EPAct), the 2009 American Recovery and Reinvestment Act (ARRA), and the 2012 American Taxpayer Relief Act. 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 allowed 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, but this provision expired fully by the end of 2012. Descriptions of the various tax credits and incentives are provided below and detailed in **Table 11.**

For the high case, these tax credits and exemptions expire after the legal deadline specified for each technology and program. In the mid and low cases, the tax benefits in place today are assumed to extend indefinitely. The assumption that tax credits will continue for the foreseeable future is driven by the behavior of investors in the marketplace who continue to sign PPAs for projects that will likely come on-line after the expiration of the tax credits, but at prices that that would only be profitable with the extension of these credits. While this does not amount to a guarantee as to the future of these credits, it does reflect the willingness of investors to put their own money at risk on the likelihood that these projects will be profitable. Analysis of the effects of tax credits on levelized cost estimates for solar PV and wind technologies is presented in Chapter 10: Levelized Cost Estimates.

Renewable Electricity Production Tax Credits

The PTC was authorized under the American Taxpayer Relief Act of 2012, extended to start date of construction, and available at start of operations. The PTC is available to all technologies except solar; however, it is the better option for wind only. All other technologies benefit more under the ITC.

Renewable Energy Production Incentive

The REPI amount is adjusted for the proportion that is actually paid out from available federal funds, which is currently zero.

Accelerated Depreciation

Accelerated depreciation is available to all renewable technologies. It reduces the depreciation period to 5 years as opposed to 30 years for wind and 20 year for the other technologies.

Geothermal Depletion Allowance

Geothermal can get a tax benefit as its well gets depleted. However, this benefit is less than the benefit of the ITC; thus, it is not included.

Table 11: Federal Renewable Energy Tax Incentives

Technology	Wind	Biomass Open Loop (Ag waste)	Geothermal	Solar
Investment Tax Credit (ITC)				
Credit	30%[1]	30%[1]	10%	30%/10%[2]
Depreciable Value Reduced			5%	15%/5%
Present Expiration[3]	2014	2014	No Expiration[4]	2017
Assumed Expiration[5]	2030	2030	No Expiration[4]	2030
Loss Carry Forward Period (Years)			20	20
Eligibility	Merchant/ IOU	Merchant/ IOU	*Merchant*	Merchant/ IOU
Production Tax Credit (PTC)				
Credit (2008$)/MWh	$21	$10	$21	
Credit (1993$)/MWh	$15	$7.50	$15	
Duration (Years)	10	10	10	
Expiration[3]	2014	2014	2014	
Eligibility	Merchant	Merchant	Merchant	
Production Incentive (REPI)[6]				
Tier I Payment	$0.00		$0.00	$0.00
Tier II Payment		$0.00		
Duration (Years)	10	10	10	10
Expiration[5]	2027	2027	2027	2027
Eligibility	POU/ Coops	POU/ Coops	POU/ Coops	POU/ Coops
Accelerated Depreciation				
Normal Depreciation	30	20	20	20
Accelerated Depreciation	5	5	5	5
Eligibility	Merchant/ IOU	Merchant/ IOU	Merchant/ IOU	Merchant/ IOU

Source: Energy Commission.

Notes:

1. Adjusted from PTC by ARRA.
2. Solar ITC reverts to 10 percent in 2016.
3. Expiration per existing law. Technology only needs to start construction in the last day of the previous year.
4. Geothermal ITC has no expiration date.
5. ITC is assumed to be renewed to the end of the study period.
6. REPI payments assumed = 0 percent as these have not been funded since 2009.

Financing Assumptions for Different Generation Ownership Structures

The specific financial assumptions used to calculate the levelized cost of a project depend on the terms that are available to the borrower. This means different ownership structures will require that different assumptions are made to estimate the cost of a new project. Financial assumptions include capital structure (amount of debt versus equity), debt term, and economic/book life.

Table 12 summarizes the capital cost structure assumptions used in the COG Model to produce levelized costs outlined in Chapter 10. **Table 13** summarizes technology-specific parameters for merchant renewable plants.

The debt-to-equity split is different for merchant natural gas-fired plants than other technology plants (renewables and alternative technologies). The rationale is that financial institutions are likely to see PPAs signed under legislative and regulatory mandates, such as the RPS, as less risky than those signed under open-market conditions.

Table 14 summarizes the debt term and book life assumptions used in the COG Model. The debt term and equipment life assumptions determine the period over which the loans must be paid (debt term) and then the period over which costs are incurred and the revenues can be generated (book life). These two assumptions play an important role in determining the levelized cost of a project and, therefore, the economic viability.

Table 12: Capital Cost Structure

Mid Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	33%	13.25%	4.52%	6.17%
Merchant Alternative	40%	Variable*	Variable*	Variable*
IOU	55.%	10.04%	5.28%	6.93%
POU	N/A	N/A	3.20%	3.20%
High Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	60%	15.00%	6.63%	10.57%
Merchant Alternative	50%	Variable*	Variable*	Variable*
IOU	70%	10.31%	5.65%	8.22%
POU	N/A	N/A	5.96%	5.96%
Low Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	20.00%	10.41%	4.64%	4.28%
Merchant Alternative	25.00%	Variable*	Variable*	Variable*
IOU	9.71%	9.71%	4.55%	6.06%
POU	N/A	N/A	3.02%	3.02%

Source: Energy Commission.

Variable* financial structures are shown in **Table 13**.

Table 13: Financial Parameters for Merchant-Owned Renewables

Technology	Cost of Equity			Debt		WACC
Mid Case						
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass & Geothermal	13.25%	8.00%	12.41%	60.00%	6.31%	7.21%
Solar Technologies	13.25%	8.00%	12.41%	60.00%	5.91%	7.07%
Wind Technologies	13.25%	8.00%	11.34%	60.00%	5.91%	6.64%
High Case						
Technology	**Cost of Equity**			**Debt**		**WACC**
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass & Geothermal	15.00%	10.00%	14.20%	50.00%	7.63%	9.36%
Solar Technologies	15.00%	10.00%	14.20%	50.00%	7.36%	9.28%
Wind Technologies	15.00%	10.00%	14.20%	50.00%	7.36%	9.28%
Low Case						
Technology	**Cost of Equity**			**Debt**		**WACC**
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass & Geothermal	10.41%	7.00%	9.17%	75.00%	5.12%	4.57%
Solar Technologies	10.41%	7.00%	9.86%	85.00%	4.59%	3.79%
Wind Technologies	10.41%	7.00%	9.17%	85.00%	4.59%	3.69%

Source: Energy Commission.

Table 14: Debt Term and Book Life Assumptions

Technology	Debt Term* (Years)			Book Life (Years)		
	Mid Case	High Case	Low Case	Mid Case	High Case	Low Case
Generation Turbine 49.9 MW	10	7	20	30	20	30
Generation Turbine 100 MW	10	7	20	30	20	30
Generation Turbine—Advanced 200 MW	10	7	20	30	20	30
Combined Cycle—2 CTs No Duct Firing 500 MW	10	7	20	30	20	30
Combined Cycle—2 CTs With Duct Firing 550 MW	10	7	20	30	20	30
Biomass Fluidized Bed Boiler 50 MW	20	15	25	30	20	30
Geothermal Binary 30 MW	20	15	25	30	20	30
Geothermal Flash 30 MW	20	15	25	30	20	30
Solar Parabolic Trough W/O Storage 250 MW	20	15	25	30	20	30
Solar Parabolic Trough With Storage 250 MW	20	15	25	30	20	30
Solar Power Tower W/O Storage 100 MW	20	15	25	30	20	30
Solar Power Tower With Storage 100 MW 6 HRs	20	15	25	30	20	30
Solar Power Tower With Storage 100 MW 11 HRs	20	15	25	30	20	30
Solar Photovoltaic (Thin-Film) 100 MW	20	15	25	30	20	30
Solar Photovoltaic (Single Axis) 100 MW	20	15	25	30	20	30
Solar Photovoltaic (Thin-Film) 20 MW	20	15	25	30	20	30
Solar Photovoltaic (Single Axis) 20 MW	20	15	25	30	20	30
Wind—Class 3 100 MW	20	15	25	30	20	30
Wind—Class 4 100 MW	20	15	25	30	20	30

Source: Energy Commission.

* Debt term values are for merchant plants, only. IOU and POU are equal to book life for all three cost cases.

The federal and state tax lives are used to set the federal and state tax depreciation periods. Federal is 20 years for gas-fired units and 5 years for renewable technologies. State is 15 years for gas-fired units and 20 for renewable. The base federal tax life is taken from *Internal Revenue Service Publication 946*, Appointment B, Asset Class 49, but scenarios were run where the tax life could vary for a technology, for example, generation turbines (IRS, 2014). 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.

CHAPTER 3: Emission Mitigation, Fuel, and Transmission Interconnection Costs

While each project and generation technology brings a unique set of costs and underlying trends, there are three cost components that are independent of the technology type. These include costs for environmental mitigation such as emissions credits that do not affect all technologies equally but are based on the emissions profile of the technology, fuels such as natural gas or biomass for power plants, and interconnection transmission equipment to deliver energy from the generator to the interconnection point. The following describes the assumptions for these cost components and how they were incorporated in estimating costs for the different technologies.

Emission Mitigation Costs

Environmental mitigation measures have become increasingly important components of power plant costs, for both fossil-fueled and renewable generators. For natural gas-fired generators, the largest compliance cost component usually is criteria pollutant emission reduction credits (ERC); for renewables, it is habitat mitigation and land acquisition. Other compliance costs include the regulatory permit application, processing, and monitoring costs. Environmental mitigation generally is incorporated directly into the plant construction cost estimates reported here, as most sources do not separately distinguish those costs. Future research on the magnitude of those costs and the differences across jurisdictions could allow better delineation of those costs.

The exception is the environmental mitigation costs for natural gas-fired plants. Staff surveyed costs for existing plants within California, including all ancillary costs. The environmental permitting costs, land costs, and interconnection transmission costs are listed as separate items as inputs to the COG Model based on the survey responses. ERC costs are further segmented because those costs have a distinct trend that can be estimated with historical data.

A new source of environmental mitigation costs is for greenhouse gas (GHG) allowances under the ARB California Cap-and-Trade Program (CCTP). Compliance is based on actual annual operations rather than meeting a specific emission rate threshold, and allowances are auctioned by the ARB several times a year. The costs associated with allowances are more akin to fuel costs and are represented in the COG Model as annual expenses rather than upfront capital investment, as is the case for the ERCs.

Emission Reduction Credits

New power plants must comply with air quality regulations enforced by local air districts under the state and federal Clean Air Acts, also called New Source Review (NSR). Whether a particular power plant needs to meet emission limits depends on whether the power plant is located is an air basin that is in compliance with federal and state ambient air quality standards.[15] When in a nonattainment area, power plants must not exceed maximum emission rates and further reduce emissions at other existing regional sources by acquiring ERCs (at an offset ratio ranging from 1.0 to 1.5) to compensate for the new emissions from the power plant. The ERC represents an entitlement to emit at a daily rate (usually pounds or tons per day) for the life of the project. Most commonly ERCs are bought through brokers or similar market institutions.

In several cases, most notably the South Coast Air Quality Management District (SCAQMD), ERCs are either available only through a community bank or not at all. SCAQMD'S Rule 1304 provides an exemption to the requirement for ERCs to offset any emission increases for the replacement of an electric steam utility boiler to more efficient or advanced technology. Under this exemption, SCAQMD has been retiring offsets from the district's internal account without a fee. A recent change to Rule 1304 allows SCAQMD to charge a fee for utility boiler replacement. However, there is an exemption for utility boiler replacements when they are replaced with CC or advanced intercooled gas turbines and there is no increase in the MW.

Emission Factors and Permitting Operational Assumptions

ERC costs for any new power plant are a function of three factors: criteria pollutant emission factors, operational parameters used in the permit, and the price per ton permitted. The criteria pollutant emission factors used in the COG Model are based on recent projects and provided in **Table 15**. The criteria pollutant emissions are based on permitted rather than actual emissions, which are assumed to be related to a consistent interpretation of best available control technology requirements within California. Therefore, average, high, and low values do not apply.

15 "2002 Area Designations," see <http://www.arb.ca.gov/regact/2012/area12/area12.htm>.

Table 15: Recommended Criteria Pollutant Emission Factors (lbs/MWh)

Technology	NO_x	VOC	CO	SO_x	PM10
Conventional SC[a]	0.279	0.054	0.368	0.013	0.134
Advanced SC	0.099	0.031	0.19	0.008	0.062
Conventional CC	0.07	0.024	0.208	0.005	0.037
Conventional CC w/Duct Firing	0.076	0.018	0.315	0.005	0.042
Biomass Fluidized Bed Boiler 50 MW	0.075	0.012	0.105	0.034	0.100
Geothermal Flash 30 MW	0.191	0.011	0.058	0.026	0.000

Source: Energy Commission.

Notes:

a The conventional SC values are used for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

Natural gas-fired power plants are required to purchase sufficient emissions permits to allow them to run well beyond their average annual generation. For CC plants, the model assumes the plant will operate only at 57 percent CF but must purchase emissions credits sufficient to allow operation as a base load resource, with a 90 percent CF. For SC plants, the model uses typical permit level of 3,000 hours per year (about 34 percent CF); however, these plants rarely run beyond a 10 percent CF. The biomass and geothermal emission costs are based on Energy Commission staff-estimated CFs.

ERC Price Trends

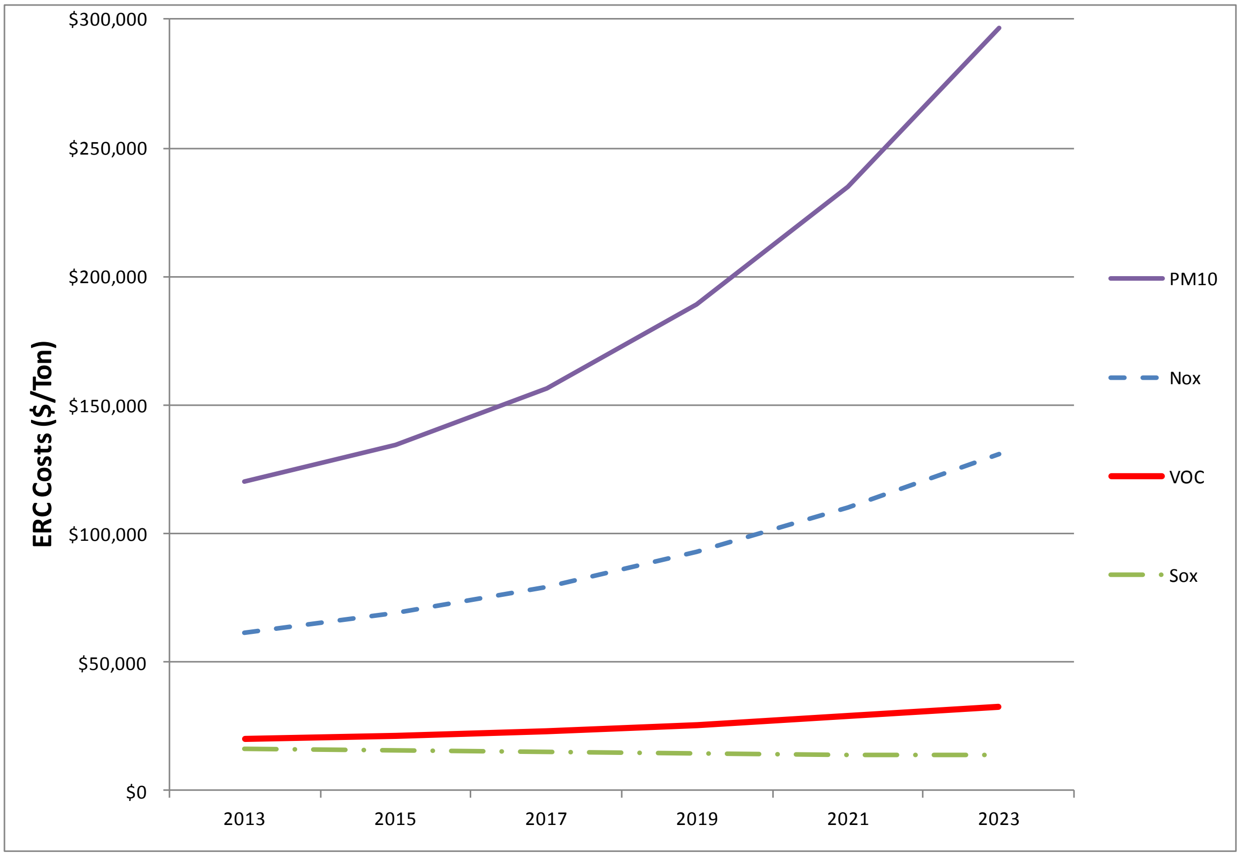
The ARB has tracked reported ERC prices since 1993.[16] These markets are "thin" with few transactions and few participants, so price data can vary widely. Regardless, prices have shown a general upward trend, particularly for those pollutants that are most tightly regulated, for example, oxides of nitrogen (NO_x), volatile organic compounds (VOC), oxides of sulfur (SO_x) and particulate matter (PM).[17] Staff developed price projections for ERCs for these pollutants that represent aggregations of several nonattainment districts.[18] These prices are then multiplied by the offset ratios applicable for the specific region or district.

16 "New Source Review…," see <http://www.arb.ca.gov/nsr/erco/erco.htm>.

17 While an estimate of SOx prices are included in the model, a lack of data made regional estimates impossible. A single SOx price estimate is applied on a statewide basis.

18 The forecasts are pooled time-series across the regions and for the period from 1993 to 2011, with a trend regressed on the log of the ERC prices and multiplicative interactive terms with the regions.

Figure 5: Emission Reduction Credit Price Forecasts From 2013 to 2023 (Nominal $/Ton)



Source: Energy Commission.

Table 16 quantifies the effect of ERCs on Instant Costs and LCOE for 2013 and 2024.

Table 16: ERCs as Percentages of Total Instant Costs and LCOE—Mid Case

ERC as Percentages of Total Cost	ERC as a % of Instant Cost		ERC as a % of LCOE	
	Year = 2013	Year = 2024	Year = 2013	Year = 2024
Generation Turbine 49.9 MW	4.5%	12.3%	3.2%	8.7%
Generation Turbine 100 MW	4.5%	12.4%	3.2%	8.7%
Generation Turbine—Advanced 200 MW	2.3%	6.6%	1.5%	4.0%
Combined Cycle—2 CTs No Duct Firing 500 MW	3.8%	10.7%	1.2%	3.0%
Combined Cycle—2 CTs With Duct Firing 550 MW	4.3%	11.9%	1.3%	3.3%
Biomass Fluidized Bed Boiler 50 MW	1.4%	4.2%	0.6%	1.8%
Geothermal Flash 30 MW	0.0%	0.0%	0.0%	0.0%

Source: Energy Commission.

Greenhouse Gas Allowances

The CCTP is one component of the ARB's program to comply with the objectives in Assembly Bill 32 Global Warming Solutions Act, (Núñez, Chapter 488, Statutes of 2006) (AB 32), which requires the statewide GHG emissions to reach 1990 levels by 2020. The CCTP officially began operation on January 1, 2013. The primary participants are electric utilities and generators, and industrial sources that emit more than 25,000 tons of carbon dioxide equivalent (CO_{2e}) annually. These industrial sources include nearly all fossil-fueled electric generators in California.[19] The ARB first auctioned allowances in November 2012 and has staged subsequent auctions in 2013 and 2014.

Greenhouse Gas Emission Rates

The carbon dioxide emission factors used in the COG Model were determined based on the efficiency for each technology, using an emission factor of 52.87 pounds per million British thermal units (lbs/MMBtu).[20] **Table 17** provides the staff's estimated carbon dioxide emission factors for each technology under three cases. The emission factors were based on the heat rates derived from the *Quarterly Fuel and Energy Report (QFER)* data filings for natural gas and from the studies reviewed for biomass and geothermal referenced in the following applicable sections. The range for biomass reflects how emissions from this technology will be handled. There is dispute among stakeholders as to whether emissions from biomass fuels should be considered a zero net emitter of GHGs, since the fuels would naturally break down emitting GHGs without being used for electric generation. The estimates shown in **Table 17** reflect this uncertainty over whether biomass emissions should be counted on net as total emissions.

19 Besides fossil-fueled generators, the CCTP also covers large industrial users, such as oil and gas extraction, large food processing plants, and manufacturers of cement and other building products.

20 Emission factor is from the ARB for natural gas with an assumed heating content (HHV [high heating value) between 1,000 and 1,025 British thermal units per standard cubic foot (Btu/scf).

Table 17: Carbon Dioxide Emission Factors Used in COG Model (Pounds per Megawatt Hour [lbs/MWh])

Technology	Mid Case	High Case	Low Case
Conventional SC[a]	1239.3	1392.1	1168.5
Advanced SC	1239.3	1392.1	1168.5
Conventional CC	1156.8	1194.2	1124.0
Conventional CC w/Duct Firing	848.8	875.8	823.1
Biomass Fluidized Bed Boiler 50 MW	195.0	195.0	0
Geothermal Binary 30 MW	0	180.0	0
Geothermal Flash 30 MW	264.5	397.0	98.9

Source: Energy Commission.

Notes:

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

Greenhouse Gas Allowance Prices

Under the CCTP, most participants received free allowances for all or a portion of their emission limit in each year through 2015, with free allowance allocations scheduled to be reduced after that date. California's overall emissions have fallen since the *AB 32 Scoping Plan*[21] was developed in 2008, largely due to the decrease in economic activity from the 2008 recession. For this reason, firms have had an easier time complying with the emission limits than originally anticipated.

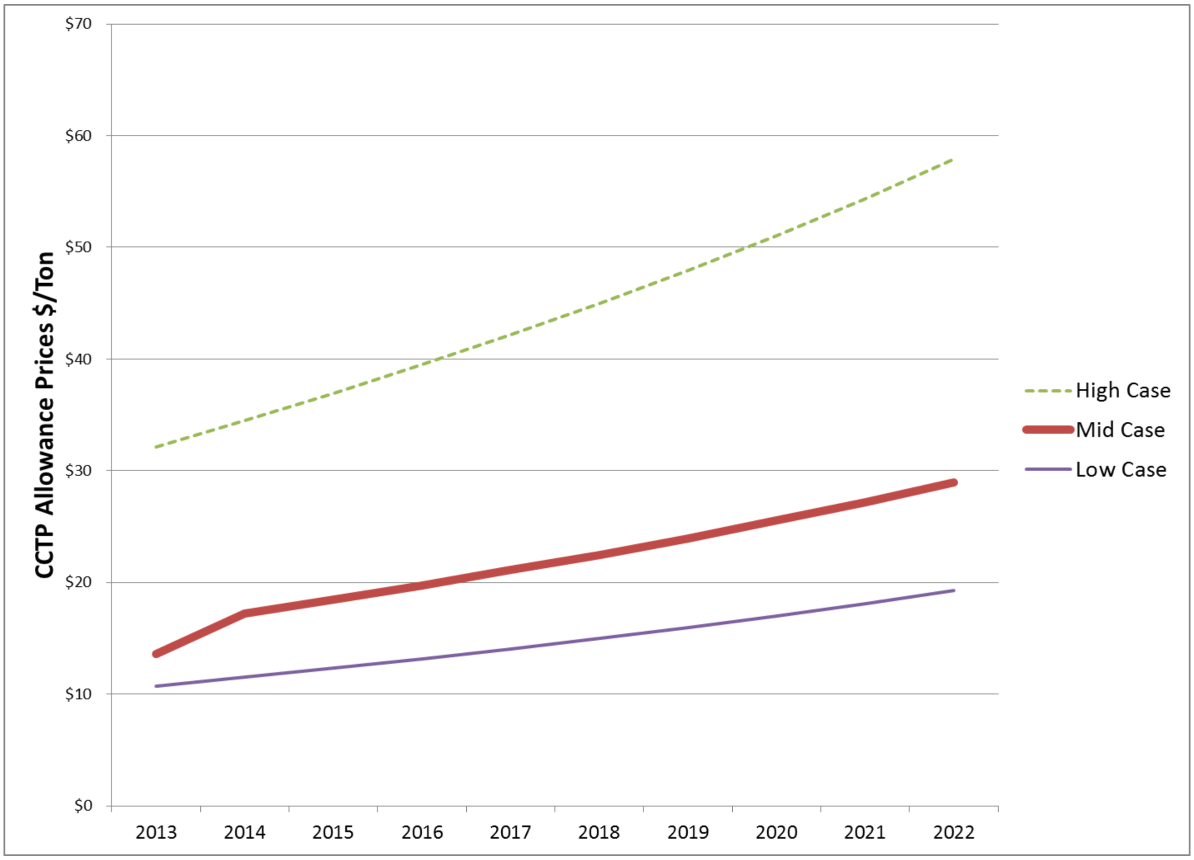
CCTP allowances are auctioned four times a year by the ARB. The auction price is bound by a minimum reserve price set at $10 per ton in 2012 and escalated at 5 percent plus inflation each year, and a ceiling of $50 in 2012, again escalated at 5 percent plus inflation per year. A recent report by the ARB's Emission Market Assessment Committee and the Market Simulation Group (EMAC and MSG, respectively) forecasted that the most likely scenarios are for the price to be at either the floor or the ceiling price, with the preponderance of probability at the lower end (Bailey, et al., 2013).

Consistent with the EMAC/MSG forecast, the November 2012 auction for 2013 allowances cleared at the floor price, indicating that a surplus of allowances was available. However, in February 2013, the auction price rose to $13.62 for 2013 allowances; similarly, secondary market prices rose to near $14 per ton in the period before and after the auction. Assuming the persistence of the allowance price remaining above the floor, the mid case estimate assumes that the price will be 50 percent above the floor price. The high-cost case assumes

21 See http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf.

the price will be three times the floor price unless it is constrained by the reserve price. **Figure 6** shows the price forecast.

Figure 6: California Cap-and-Trade Allowance Price Estimates to 2022 (2013 Nominal $)



Source: Aspen Environmental

Table 18 quantifies the impact of GHG on LCOE. GHG is as much as 14 percent of the LCOE in 2013 and as much as 20 percent in 2024.

Table 18: Effect of GHG on Total LCOE—Mid Case

Mid-Cost LCOE (Nominal $/MWh)	LCOE (2013 $/MWh)			% Of LCOE	LCOE (2024 $/MWh)			% Of LCOE
	W/O	GHG	With		W/O	GHG	With	
Generation Turbine 49.9 MW	639	23	663	3.5%	837	48	884	5.4%
Generation Turbine 100 MW	637	24	661	3.6%	834	48	882	5.4%
Generation Turbine - Advanced 200 MW	382	22	404	5.4%	489	44	533	8.3%
Combined Cycle − 2 CTs No Duct Firing 500 MW	100	16	117	13.8%	135	33	167	19.5%
Combined Cycle − 2 CTs With Duct Firing 550 MW	100	16	116	13.9%	134	33	167	19.5%
Biomass Fluidized Bed Boiler 50 MW	118	4	122	2.9%	147	7	154	4.7%
Geothermal Flash 30 MW	104	8	112	7.5%	127	17	144	11.9%

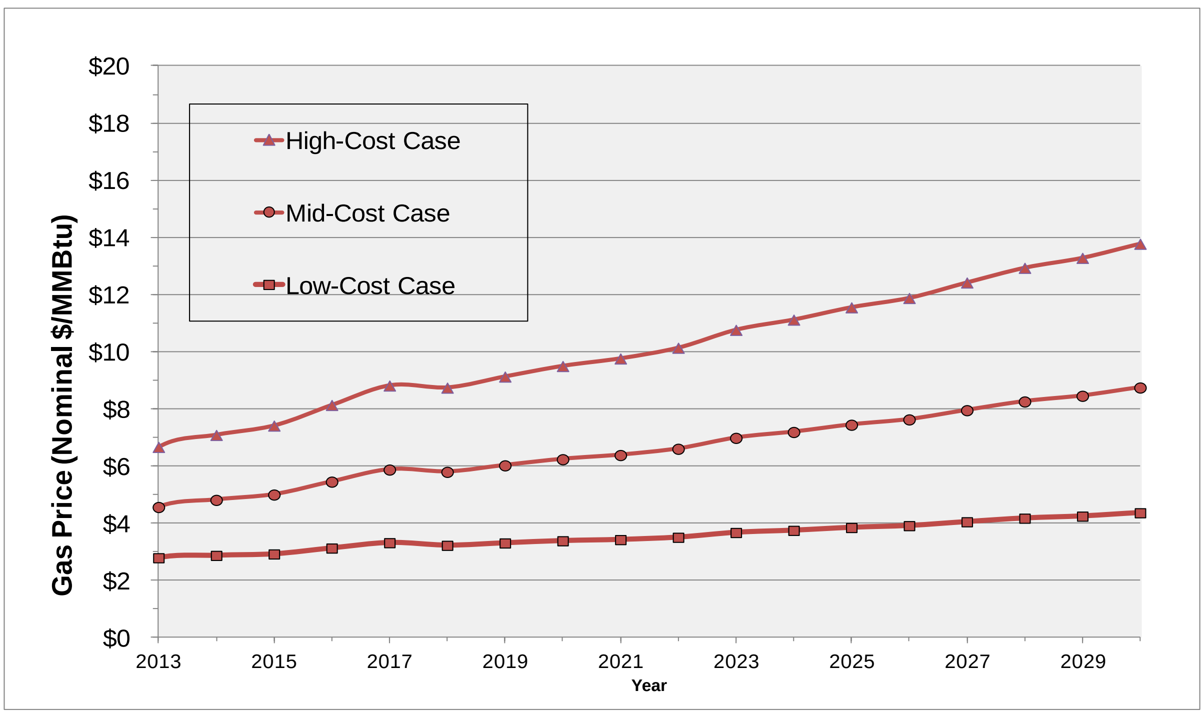
Source: Energy Commission.

Fuel Costs

Fuels for biomass and natural gas-fired power plants are major components of the cost of generation**.** Natural gas for electric generation is purchased primarily from regional market hubs for delivery via the major natural gas pipelines in California. As a result, these prices reflect the national trends in prices. Biomass fuels are produced through a process similar to a blend of farming and forestry, depending on the specific location and design of the plant. This means that prices for biomass fuels tend to be driven by localized factors and are cheaper than more standard fossil fuels, such as oil or natural gas. The price projections found by staff remain nearly unchanged from the *2009 Cost of Generation* report, and those values are used again in this report.

Figure 7 summarizes the natural gas prices through 2030 used in the COG Model. Prices are provided for three cost cases and all prices are nominal dollars.

Figure 7: California Natural Gas Price Projections



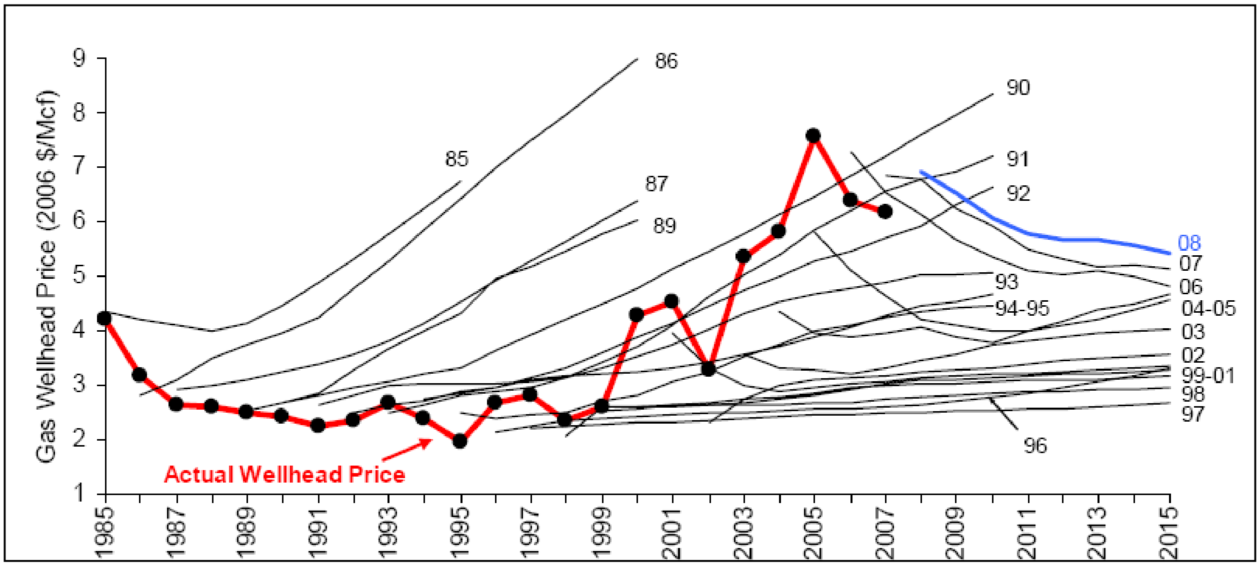
Source: Energy Commission.

Natural gas fuel cost estimates are based on wellhead prices created by the North American Market Gas-Trade Model (NAMGas Model) used by the Energy Commission to produce the

Natural Gas Outlook report for the *2013 IEPR*.[22] These values were then adjusted by staff to add transportation costs to provide burner tip natural gas prices.[23]

The future price of natural gas is difficult to estimate despite the importance to estimating the operating cost of natural gas-fired generation. **Figure 8** demonstrates the difficulties inherent in developing point forecasts of natural gas prices and the range of uncertainty experienced over the last 30 years. It compares actual wellhead natural gas prices against historical United States Energy Information Administration (U.S. EIA) forecasts.

Figure 8: Historical U.S. EIA Wellhead Natural Gas Price Forecasts vs. Actual Price



Source: Lawrence Berkeley National Laboratory (Bolinger and Wiser, 2010).

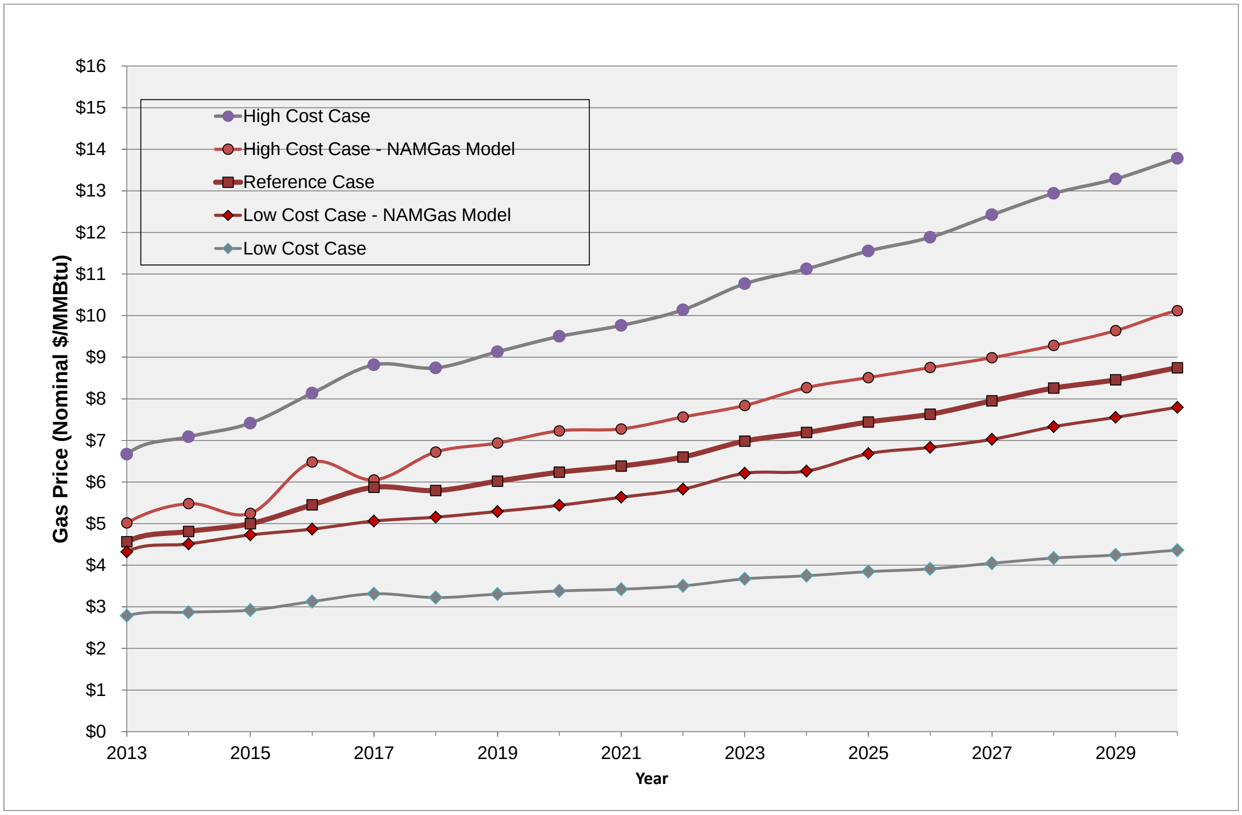
Although the NAMGas Model also provides high-cost and low-cost projections, it represents a fairly narrow range, which could imply that there is little uncertainty in underlying trends going forward. Staff has, therefore, chosen to supplement the natural gas prices produced by the NAMGas Model by using historical forecast error to provide a wider bandwidth of fuel costs, reflecting a wide range of uncertainty (Klein, 2010). Staff extrapolated from the Energy Information Administration's past success and failure in natural gas price forecasting by measuring the historical failure rate and projecting that rate into the future. These error band factors were applied to the NAMGas Model reference case to produce the high and low natural gas price series used in the COG Model. **Figure 9**

22 "Presentations for the April 24, 2013 Staff Workshop…," see <http://www.energy.ca.gov/2013_energypolicy/documents/index.html#04242013>.

23 A "burner tip" price is the full price of gas paid that includes the commodity price, as well as the price to transport it to the plant for consumption.

shows a comparison of staff's estimated natural gas fuel costs to the NAMGas Model high-low projections with those used by the COG Model.

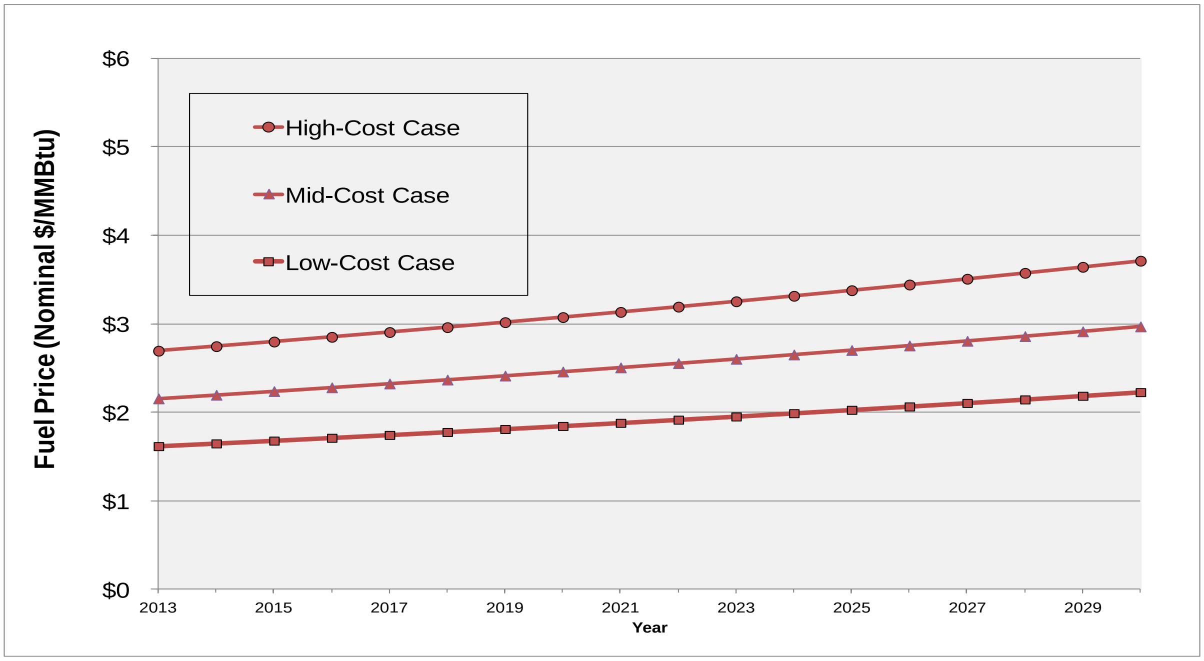
Figure 9: COG Price Projections Compared to NAMGas High-Cost and Low-Cost Forecasts



Source: Energy Commission.

Figure 10 shows biomass fuel prices over the same period. These are carried over from the 2009 COG Model and were originally developed under contract by KEMA. These 2009 values are adjusted for inflation because no new price information was available. Prices are provided for three cost cases, and all prices are nominal dollars.

Figure 10: Biomass Prices in California



Source: Energy Commission (2009 Renewables Study).

Transmission Interconnection Costs

The cost of connecting a new generation project to the electric grid typically falls to the developer. The costs to build a new central station power plant, of any technology, includes the cost of building electric transmission lines from the generating station to the point of interconnection with the electricity grid, usually at a substation, and the cost of adding hardware at the interconnection point to allow the plant to tie-in to the grid. The cost of interconnection is separate from the costs associated with the new transmission tie-line but are discussed together in this section since they are naturally related by the function they serve for the new power plant. In addition to the cost of the new transmission infrastructure, there are the costs overcoming of the electric losses between the generating station and point of interconnection.

Interconnection and Transmission Costs

All estimates of costs and electrical losses depend on two factors—voltage and distance. There is an inverse relationship between voltage and the electrical losses in a transmission line. This means that as voltage increases, the losses decrease. For this report, staff used information collected by Aspen Environmental to construct a matrix estimating the voltage at which each technology would interconnect. The higher the nameplate capacity of the power plant, the higher the associated voltage.

Table 19 summarizes the combined costs for both the substation interconnection and new transmission lines needed for each generation type.

Table 19: Combined Interconnection Transmission Costs and Transmission Voltage

Technology	Voltage	Nominal 2013 $/kW		
		Mid Case	High Case	Low Case
Generation Turbine 49.9 MW	69kV	166.9	421.4	99.1
Generation Turbine 100 MW	115kV	91.2	226.1	54.7
Generation Turbine - Advanced 200 MW	230kV	159.3	353.6	101.4
Combined Cycle − 2 CTs No Duct Firing 500 MW	230kV	63.7	141.5	40.6
Combined Cycle − 2 CTs With Duct Firing 550 MW	230kV	59.0	133.9	37.1
Biomass Fluidized Bed Boiler 50 MW	69kV	166.6	420.5	98.9
Geothermal Binary 30 MW	69kV	277.7	700.9	164.9
Geothermal Flash 30 MW	69kV	277.7	700.9	164.9
Solar Parabolic Trough W/O Storage 250 MW	230kV	127.5	282.9	81.1
Solar Parabolic Trough With Storage 250 MW	230kV	127.5	282.9	81.1
Solar Power Tower W/O Storage 100 MW	115kV	91.2	226.1	54.7
Solar Power Tower With Storage 100 MW 6 HRs	115kV	91.2	226.1	54.7
Solar Power Tower With Storage 100 MW 11 HRs	115kV	91.2	226.1	54.7
Solar Photovoltaic (Thin-Film) 100 MW	115kV	91.2	226.1	54.7
Solar Photovoltaic (Single Axis) 100 MW	115kV	91.2	226.1	54.7
Solar Photovoltaic (Thin-Film) 20 MW	69kV	416.5	1051.3	247.3
Solar Photovoltaic (Single Axis) 20 MW	69kV	416.5	1051.3	247.3
Wind − Class 3 100 MW	115kV	91.2	226.1	54.7
Wind − Class 4 100 MW	115kV	91.2	226.1	54.7

Source: Energy Commission.

Table 20 shows how the transmission cost affects the instant cost as a percentage of the total instant cost, which ranges from 1 percent to 27 percent, depending on the technology and the year.

The low-cost case substation interconnection costs were derived from utility filings with the CPUC by Southern California Edison showing the cost to interconnect to a substation at each voltage level if there were no upgrades needed. To estimate the mid case and high case values, the low case values were escalated by factors of 1.5 and 3, respectively.

Transmission line costs per mile were derived from the WECC report on transmission costs estimators for each voltage level. The values presented in the WECC report formed the basis for the mid-cost case. The low-cost case is derived by taking three-fourths of the mid-cost values, while the high-cost case is derived by multiplying the mid-cost case by 1.5.

Table 20: Interconnection Transmission as a Percentage of Total Instant Cost

Transmission Cost (% of Instant Cost)	Year = 2013			Year = 2024		
	Mid Case	High Case	Low Case	Mid Case	High Case	Low Case
Generation Turbine 49.9 MW	13.6%	24.4%	12.5%	12.5%	22.8%	10.7%
Generation Turbine 100 MW	7.5%	13.2%	7.0%	6.9%	12.3%	5.9%
Generation Turbine - Advanced 200 MW	16.1%	23.7%	17.7%	15.4%	23.0%	16.2%
Combined Cycle − 2 CTs No Duct Firing 500 MW	6.4%	12.5%	5.2%	5.9%	11.6%	4.5%
Combined Cycle − 2 CTs With Duct Firing 550 MW	6.0%	11.9%	5.0%	5.5%	11.0%	4.3%
Biomass Fluidized Bed Boiler 50 MW	3.7%	7.7%	3.0%	3.6%	7.3%	2.9%
Geothermal Binary 30 MW	5.2%	10.2%	3.7%	5.2%	10.1%	3.7%
Geothermal Flash 30 MW	4.6%	8.6%	4.4%	4.5%	8.4%	4.2%
Solar Parabolic Trough W/O Storage 250 MW	3.3%	5.9%	2.7%	4.5%	6.5%	4.4%
Solar Parabolic Trough With Storage 250 MW	2.3%	3.5%	1.6%	3.2%	4.0%	2.6%
Solar Power Tower W/O Storage 100 MW	2.2%	4.2%	1.5%	3.0%	4.6%	2.5%
Solar Power Tower With Storage 100 MW 6 HRs	1.6%	3.2%	1.1%	2.1%	3.5%	1.8%
Solar Power Tower With Storage 100 MW 11 HRs	1.4%	3.1%	0.9%	1.9%	3.4%	1.7%
Solar Photovoltaic (Thin-Film) 100 MW	2.9%	6.2%	1.9%	5.5%	10.5%	3.7%
Solar Photovoltaic (Single Axis) 100 MW	2.5%	5.5%	1.6%	3.5%	7.5%	2.3%
Solar Photovoltaic (Thin-Film) 20 MW	12.0%	23.6%	8.0%	20.9%	35.3%	14.8%
Solar Photovoltaic (Single Axis) 20 MW	10.5%	21.2%	6.9%	14.3%	27.4%	9.6%
Wind − Class 3 100 MW	4.8%	8.5%	3.6%	6.9%	9.8%	5.0%
Wind − Class 4 100 MW	5.0%	9.2%	3.9%	7.1%	10.5%	5.4%

Source: Energy Commission

Table 21 shows the effect of the interconnection transmission on total cost, expressed as LCOE. Transmission costs range from 2 percent to 12 percent in 2013 and up to 17 percent in 2024.

Table 21: The Effect of Transmission Costs on Total LCOE

LCOE ($/MWh)	Year = 2013			% Of LCOE	Year = 2024			% Of LCOE
	W/O	Transmission	With		W/O	Transmission	With	
Generation Turbine 49.9 MW	594	69	663	10.4%	801	83	884	9.4%
Generation Turbine 100 MW	619	42	661	6.3%	831	51	882	5.8%
Generation Turbine − Advanced 200 MW	361	43	404	10.5%	482	51	533	9.6%
Combined Cycle − 2 CTs No Duct Firing 500 MW	114	2	117	2.1%	165	3	167	1.7%
Combined Cycle − 2 CTs With Duct Firing 550 MW	114	2	116	1.9%	164	3	167	1.6%
Biomass Fluidized Bed Boiler 50 MW	120	2	122	2.0%	151	3	154	2.0%
Geothermal Binary 30 MW	86	5	91	5.1%	104	6	110	5.1%
Geothermal Flash 30 MW	108	5	112	4.4%	138	6	144	4.2%
Solar Parabolic Trough W/O Storage 250 MW	164	5	168	2.7%	151	5	156	3.4%
Solar Parabolic Trough With Storage 250 MW	125	3	127	2.1%	114	3	117	2.6%
Solar Power Tower W/O Storage 100 MW	149	4	153	2.7%	129	4	134	3.3%
Solar Power Tower With Storage 100 MW 6 HRs	142	3	146	2.2%	129	3	133	2.6%
Solar Power Tower With Storage 100 MW 11 HRs	112	2	114	2.1%	101	3	104	2.5%
Solar Photovoltaic (Thin-Film) 100 MW	107	4	111	3.4%	77	4	81	5.0%
Solar Photovoltaic (Single Axis) 100 MW	106	3	109	3.1%	95	4	98	3.8%
Solar Photovoltaic (Thin-Film) 20 MW	107	14	121	11.6%	77	16	93	17.3%
Solar Photovoltaic (Single Axis) 20 MW	106	12	118	10.3%	95	14	109	12.9%
Wind − Class 3 100 MW	80	6	85	6.6%	70	5	75	6.4%
Wind − Class 4 100 MW	79	6	84	6.8%	71	5	76	6.6%

Source: Energy Commission

Transmission Losses

Along with the direct costs to build new transmission lines and connect to the grid, the distance a power plant locates from the point of interconnection has an indirect effect on costs. Losses increase with distance, and therefore plants located farther from the interconnection point will deliver less energy to the grid than an identical plant located closer. This reduction in energy delivered causes the overall costs to per unit of energy to increase with the length of the line. Typically, conventional resources are able locate near load centers and along existing transmission corridors because the fuel can be delivered to the power plant. Renewable resources must be located at the energy source, which typically is farther from load centers or transmission corridors. This pattern has not been as evident in recent years and is unlikely to hold as a firm "rule of thumb" going forward because new transmission lines are located closer to renewable resources expressly to help overcome this issue. Furthermore, the lengths of the transmission interconnection lines vary widely by project. Therefore, this report uses three standard lengths (0.5 miles, 1.5 miles, and 5 miles) for all technologies to estimate the low, mid, and high cases, respectively.

Transmission losses occur between the *busbar*[24] or generator and the point of first interconnection to the transmission grid, usually a local substation that then feeds into the high-voltage transmission network. *Tie-lines* are the transmission lines that connect the generation resource to the electrical substation. Losses vary depending on the voltage and length of the line. Losses increase as voltage decreases. Smaller facilities, more common for renewables, are typically connected to lines operating at lower voltages and experience higher losses. Since the distances associated with each generation type vary on a case-by-case basis, distances from the generator to the substation were standardized for all technologies. **Table 22** shows the distances and estimated losses for various sizes of interconnections.

24 A *busbar* is the physical point of connection where the transmission lines connect to the generator.

Table 22: Assumed Interconnection Transmission Lengths and Losses

Length of Interconnection	Mid Case	High Case	Low Case
Transmission Losses (%)	**1.5 mi**	**5 mi**	**0.5 mi**
Generation Turbine 49.9 MW	0.65%	2.18%	0.22%
Generation Turbine 100 MW	0.97%	3.23%	0.32%
Generation Turbine − Advanced 200 MW	0.22%	0.72%	0.07%
Combined Cycle − 2 CTs No Duct Firing 500 MW	0.09%	0.31%	0.03%
Combined Cycle − 2 CTs With Duct Firing 550 MW	0.09%	0.31%	0.03%
Biomass Fluidized Bed Boiler 50 MW	0.47%	1.57%	0.16%
Geothermal Binary 30 MW	0.94%	3.14%	0.31%
Geothermal Flash 30 MW	0.94%	3.14%	0.31%
Solar Parabolic Trough W/O Storage 250 MW	0.22%	0.72%	0.07%
Solar Parabolic Trough With Storage 250 MW	0.22%	0.72%	0.07%
Solar Power Tower W/O Storage 100 MW	0.97%	3.23%	0.32%
Solar Power Tower With Storage 100 MW 6 HRs	0.97%	3.23%	0.32%
Solar Power Tower With Storage 100 MW 11 HRs	0.97%	3.23%	0.32%
Solar Photovoltaic (Thin-Film) 100 MW	0.97%	3.23%	0.32%
Solar Photovoltaic (Single Axis) 100 MW	0.97%	3.23%	0.32%
Solar Photovoltaic (Thin-Film) 20 MW	1.37%	4.56%	0.46%
Solar Photovoltaic (Single Axis) 20 MW	1.37%	4.56%	0.46%
Wind − Class 3 100 MW	0.97%	3.23%	0.32%
Wind − Class 4 100 MW	0.97%	3.23%	0.32%

Source: Energy Commission

CHAPTER 4:
Solar Photovoltaic Technologies

Overview

Solar PV technologies are an important and growing portion of California's electricity infrastructure. Solar PV panels in California are generally crystalline silicon or thin film. While either can be fixed- or variable-axis, crystalline silicon is more commonly used for tracking, and the thin film is generally fixed-axis. The two sizes considered were 20 MW and 100 MW. The choice of sizes is meant to capture the cost difference between installations of relatively smaller utility-scale facilities and larger, more cost-effective sites.

Technology Description

Solar PV systems absorb and directly convert sunlight into electricity. The components include solar panels or modules, inverters, and the remaining hardware referred to as balance of system (BOS).

Solar PV cells are typically manufactured in a modular form to make scaling any installation straightforward. While the photovoltaic cell represents the most visible aspect of a solar PV module, the cell is usually encased in a rigid protective housing and wired to a standardized connection point for ease of installation.

Solar PV systems produce electricity in the form of direct current (DC), while the electrical grid in California operates using alternating current (AC). This means that any solar PV installation also requires an electronic part called an "inverter" to convert the DC electricity produced by the solar panels into AC electricity compatible with the electric grid. The inverter also houses control systems and other electronics that help make connection to the grid safer and easier.

For ground-mounted PV systems, the hardware portion of BOS consists primarily of the structural components required to support the panels and hold them in place. These BOS components usually include concrete or driven pier foundations to anchor the system, galvanized steel structures to support the panels, aluminum or steel clips or clamps to hold the panels to the structure, and the tracking system (controller motor, pivots, and so forth) if the system tracks the sun.

Trends and Analysis

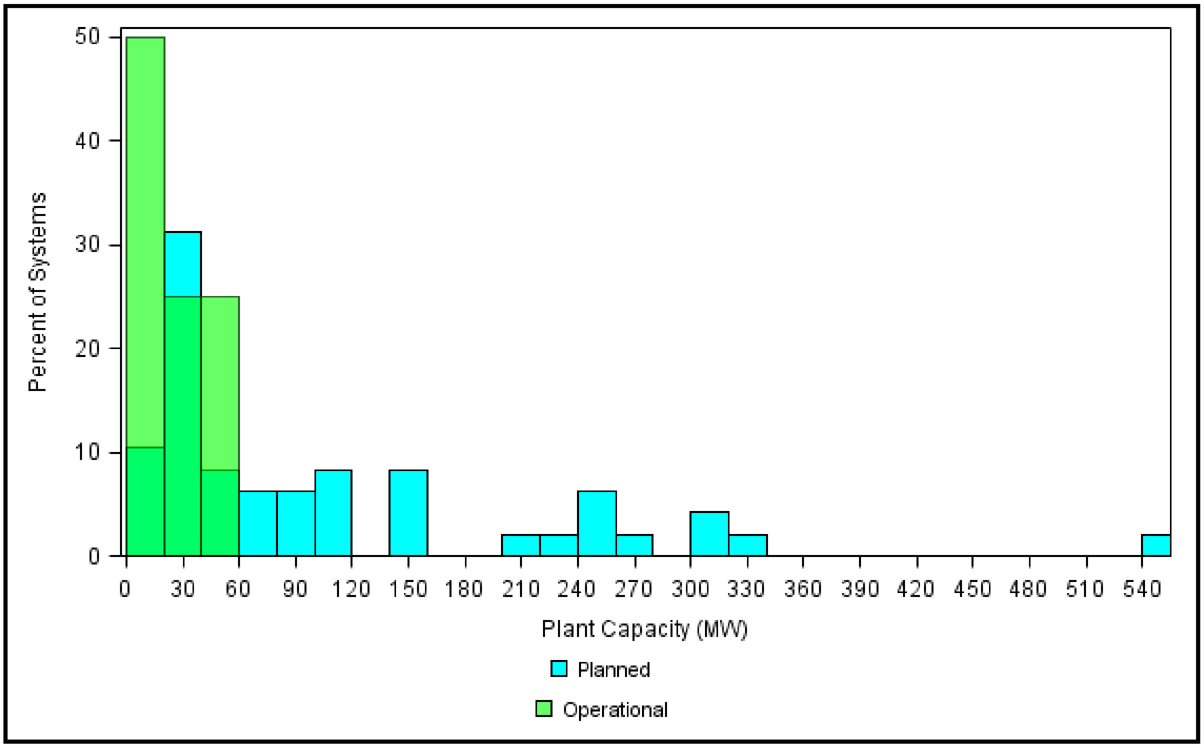
Solar PV technology costs have been the subject of a large number of studies over the last several years. This body of literature has been produced largely by researchers looking at the national marketplace for solar PV at various installation sizes. The Energy Commission hired two contractors, Navigant and Itron, to survey this body of data and extract the relevant information for utility-scale installations and adjust nationwide estimates into California-specific values. Energy Commission staff then reconciled and merged the two data sets from Navigant and Itron, using the areas where the two sources differed to understand uncertainties in the marketplace.

Trends in Solar PV Development

Many large-scale PV plants are planned, under construction, or operational throughout the state. Sizes range from the planned large 550 MW Dessert Topaz project in San Luis Obispo County to the relatively small 15 MW Boron Solar project in San Bernardino. Most of the plants currently planned or in construction are significantly larger than those currently operational.

Figure 11 shows the percentage of total projects, both planned and operational, by size of plant. The currently operational plants range from 2 MW to 60 MW, but planned solar PV plants range up to 550 MW. Planned projects in the 20 – 40 MW range represent more than 30 percent of the planned projects, but these represent less than 8 percent of the planned capacity. Conversely, systems in the 540 to 560 MW range represent less than 5 percent of the planned systems but nearly 10 percent of the planned capacity.

Figure 11: Sizes of Planned and Operational Photovoltaic Plants



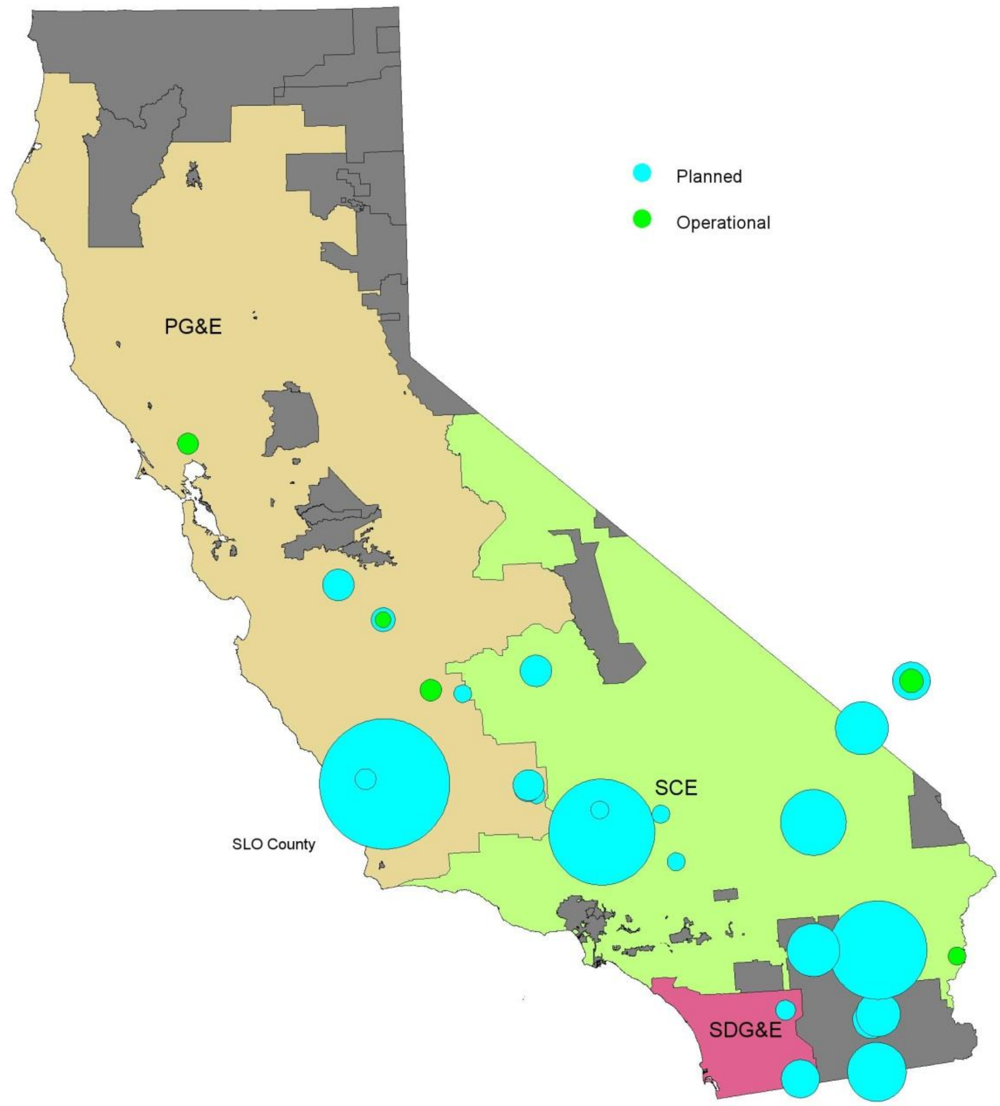
Source: Aspen Environmental.

Large-scale PV projects are clustered in the southern part of the state, an area that tends to have more sun than the northern part of the state. A few plants selling power to the California market are located in Nevada and Arizona.

Figure 12 shows locations of PV plants that are tracked by the CPUC's RPS progress status worksheet as of August 2012.[25] These plants are split between planned and operational, and the size of the marker scales with the capacity in the area of installation.

25 "RPS Project Status Table August 2012," see http://www.cpuc.ca.gov/PUC/energy/Renewables/index.html.

Figure 12: Operational and Planned Photovoltaic Plant Locations



Source: CPUC (2012).

San Luis Obispo County has the largest marker on the map, representing two solar PV units: (1) the 550 MW fixed-axis (thin-film) Desert Topaz project and (2) the 210 MW (now 250 MW) single-axis–tracking, crystalline silicon SunPower High Plains (now California Valley Solar Ranch) projects.

Cost Trends for PV Components

PV Module Prices

Historically, PV system costs have been driven largely by module prices that have constituted the majority of system costs. Recent years have seen drastic reductions in these costs as manufacturers become more efficient and producers have added significantly more manufacturing capacity than the global PV market can absorb. This excess has been due in part to the global recession, but reductions to incentives in Spain and Germany have also played a role. Finally, recent trade sanctions suggest that some countries, such as China, may have been illegally dumping panels. All these factors have worked together to bring costs down.

In addition to larger market forces, increased production of new technologies usually brings reduced costs. By fitting the empirical relationship between PV panel cost and cumulative production, a "learning curve" can be estimated and used to project future declines in costs as more modules are produced (Nemet, 2009). The estimated learning rate represents the relative reduction in cost when twice as many units have been produced. For example, a learning rate of 0.2 indicates a 20 percent drop in price for a doubling in cumulative production. **Figure 13** shows two learning curves estimated from a combination of data from two sources.

PV module production and pricing are shown in **Figure 13.** Each data point represents the average module price for one year. Because there is no single consistent time series of sources, this study relies on cost and volume data from several studies and sources representing different vintages, including the following:

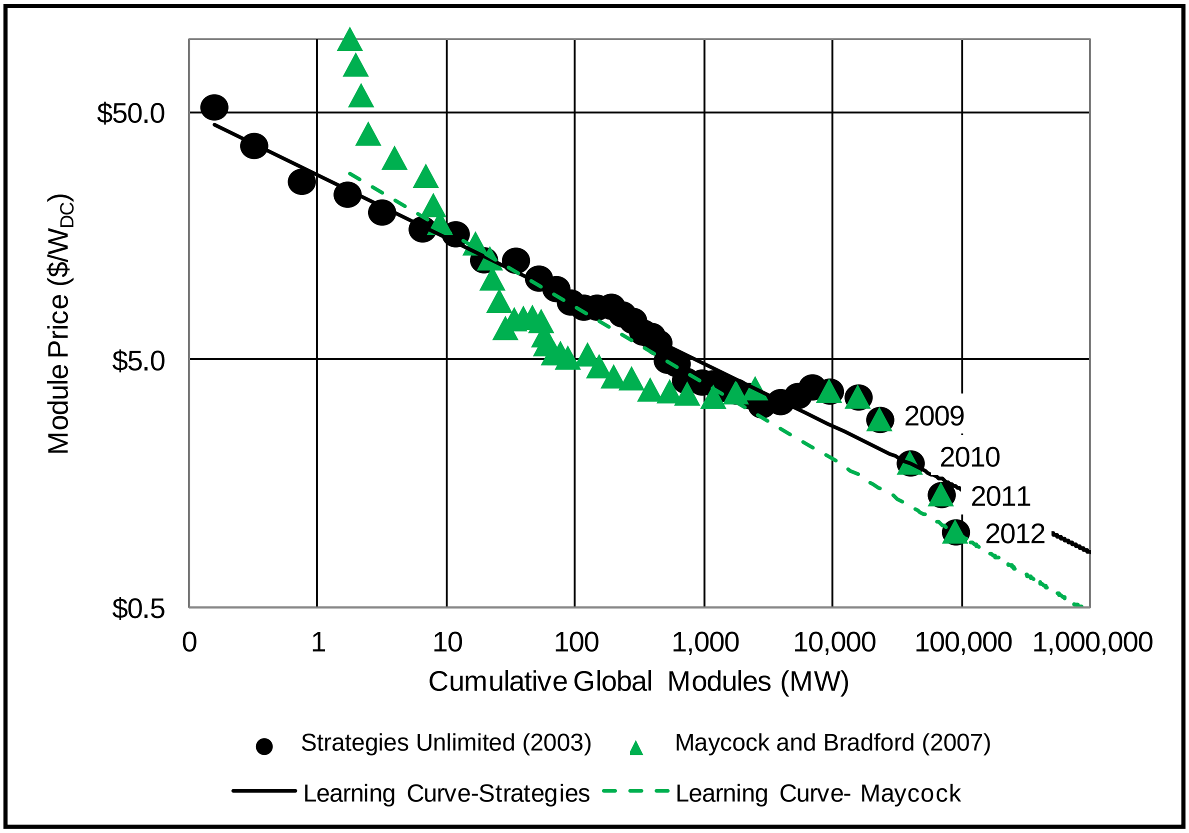
- Strategies Unlimited (2003) and Maycock and Bradford (2007) for prior to the mid-2000s.[26]
- Mehta and Bradford (2009) for 2006 to 2009.
- *Photon Magazine* for 2007 to 2012.[27]

  Recent panel volumes from 2007 to 2012 and estimates to 2016 are available from the European Photovoltaic Industry Association (EPIA) (EPIA, 2012), in addition to estimates through 2016. Both data sets in the graph use *Photon Magazine* prices and EPIA volumes for 2007 through 2012.

26 Updated data are not available beyond 2000 for Strategies Unlimited and beyond 2006 for Maycock and Bradford.

27 Average monthly spot market price from *Photon Magazine*, April 2009 through July 2012.

Figure 13: Historical Photovoltaic Modules Production and Pricing



Source: Aspen Environmental.

The data that begin with Maycock and Bradford indicate a higher price during the early days of PV in the late 1970s and 1980s, with a slightly lower price in the late 1990s. This results in a steeper slope and correspondingly higher learning rate for Strategies Unlimited data of 26 percent versus 16 percent for the Maycock and Bradford data. Interestingly, the learning curve using Maycock and Bradford data passes directly through the 2012 price of $1/watt. In 2012 Near Zero released a survey of solar price experts conducted over 2011 and 2012. This survey estimated that the median price expected after cumulative production of 300 gigawatts (GW) was $0.77 per watt, and of 600 GW a price of $0.67 per watt. This forecast infers that prices will drop slightly faster than they have over the long term, although more slowly than they have in the past few years (Near Zero, 2012).

Combining these three learning curves (the two contained in **Figure 13** and Near Zero) with module volume estimates provides a range of possible module prices moving forward. **Table 23** presents high, medium, and low bases for learning curves and volume estimates. It also presents what the average linear percentage change would be with a starting point of 2012. Looking forward, the primary driver of module price reductions is expected to be a combination of research and development fueled by the U.S. DOE SunShot initiative, which is targeting $1/watt solar PV, and the natural process of learning as the industry continues to gain experience.

Table 23: Different Module Cost and Learning Curve Bases

Cost Range	Learning Curve Basis	Learning Rate	Module Volume Basis	Linearized Annual Percent Change
High Case	Near Zero	13%	10% year-over-year growth	-2.5%
Mid Case	Strategies Unlimited	16%	Mid EPIA estimate until 2016, then 20% average year-over-year growth	-5.0%
Low Case	Maycock and Bradford	20%	High EPIA estimate until 2016, then 25% average year-over-year growth	-10.0%

Source: Aspen Environmental.

Power Electronics/Inverters

Inverters and power electronics form a much smaller percentage of installed system costs than modules. Both inverters and modules are sold on a global market driven by global manufacturing and pricing. Inverters can reasonably be expected to follow a learning curve similar to PV modules since the volumes are interrelated. The ranges for inverter costs (Goodrich, et al., 2012) serve as a good foundation; therefore, similar learning assumptions and linear annual change rates are mirrored from the PV modules discussion and applied to inverters.

Balance of System—Hardware

This report uses the Black and Veatch (Black and Veatch, 2012) and the United States Department of Energy (U.S. DOE, 2012) reports to provide a range of potential costs and rates of change for the BOS costs as shown in **Table 24**.

Table 24: Hardware Balance of System Ranges

Cost Range	Basis	Annual Year-Over-Year Cost Reduction
High Case	Black and Veatch	1%
Mid Case	DOE SunShot – Business as Usual	8%
Low Case	DOE SunShot – Required to Meet SunShot Goal	12%

Source: Energy Commission.

Operations and Maintenance Costs

PV plants do not usually require extensive maintenance. The most common task is to clean the panels regularly to minimize losses due to soiling and cut or trim any vegetation in or around the array to eliminate shading. In addition, inverters have an expected life of about 10 to 15 years and typically need to be replaced at least once over the life of a system. Finally, broken or stolen panels or system supports need to be replaced as needed. This sort of replacement is most often needed after large storms or in the case of theft or fire. This report relies on Black & Veatch (2012) and U.S. DOE SunShot (2012) for the upper and lower bounds of these long-term estimates, summarized and presented in real 2011 dollars in **Table 25**.

Table 25: Solar PV Fixed Operating and Maintenance Estimates (Real 2011$)

Year	Black & Veatch	DOE SunShot
2010	$50/kW-yr. (only for 10 MW size)	$19.93/kW-yr.,[28] Inverter replacement at 15 years at $0.17/W. That adds about $6/kW-yr.
2015	$48/kW-yr.	
2020	$45/kW-yr.	$6.5 $/ kW-yr., inverter replacement at 20 years at $0.10/W

Source: Energy Commission.

Single-Axis Tracking Systems

Instant Cost Trends

The costs for PV modules have come down dramatically in the last few years, leading to much lower system prices for utility-scale plants in California and elsewhere. This reduction

28 Based on average O&M costs at Arizona Public Service's single-axis tracking PV installations.

in cost, along with the future cost declines estimated from the learning curve described earlier, is reflected in the instant costs shown for crystalline photovoltaic systems in **Figure 14**.

Instant costs are based on two project sizes, 100 MW and 20 MW,[29] and these reflect the 2011 component buildups from combined data found in four sources:

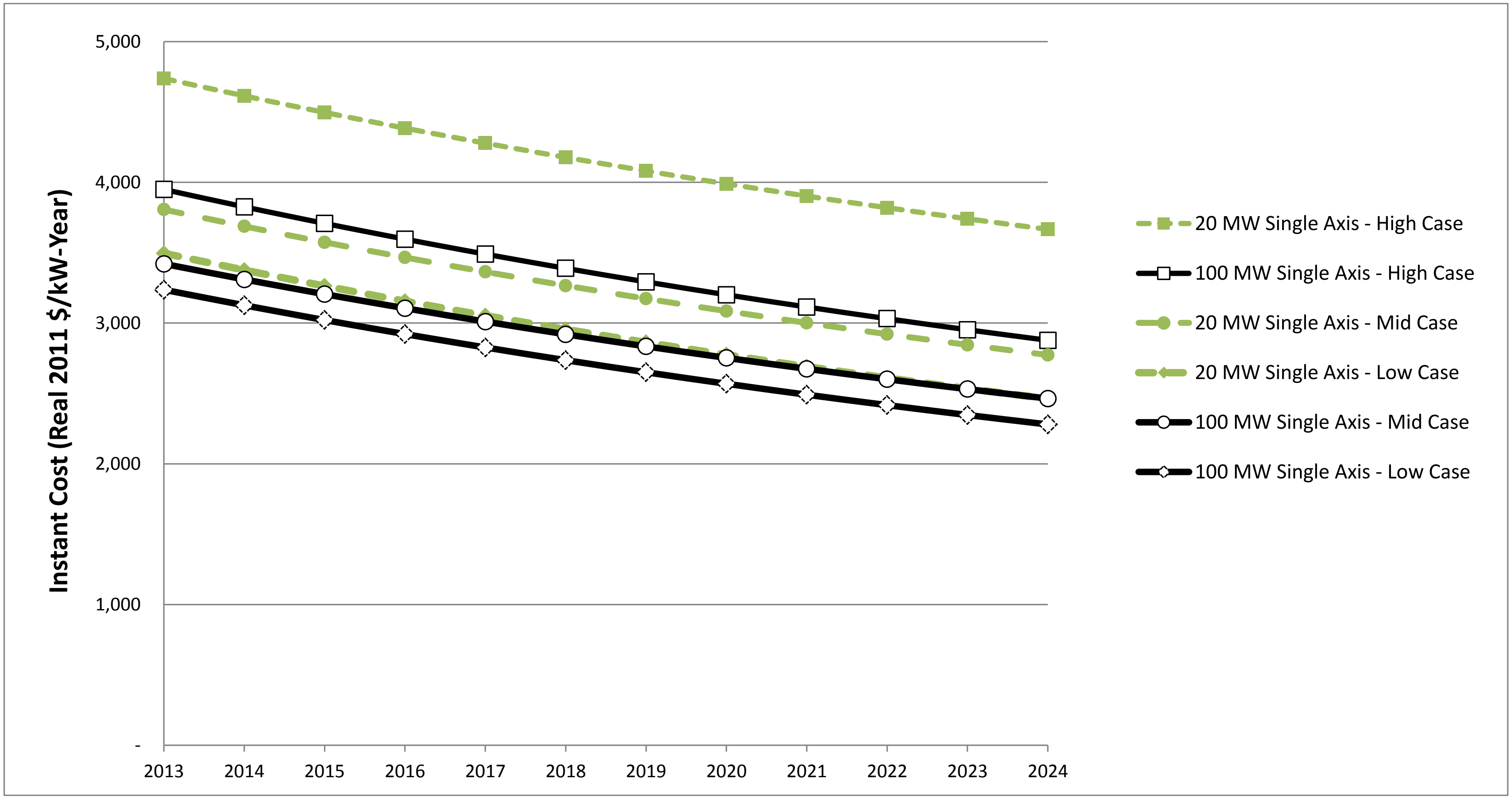
- Solar Electric Power Association's *Centralized Solar Projects and Pricing Update Bulletin* (SEPA, 2012)
- Goodrich's NREL report on current PV pricing (Goodrich et al., 2012)
- U.S. DOE's *SunShot Vision Study* (U.S. DOE, 2012)
- Module manufacturer annual and quarterly reports[30]

The instant costs in **Figure 14** represent a composite of costs that would be necessary to construct a new power plant if the plant could be built overnight. They do not include the cost of a construction loan, loan fees, or insurance. They do not include O&M costs. These costs are classified herein into four categories: equipment costs, land costs, permitting costs, and emissions costs. Technology costs include the cost of the solar panels, inverter, transformer, and other physical elements of the solar array. Land costs include the cost of purchasing and preparing the land for use as a renewable energy site. Permitting costs incorporate the cost of obtaining the needed permits for the site. Here, the authors follow Goodrich and other studies and include both the direct cost of permitting as well as the cost of delays. For solar, there are no emissions, and, therefore, the values are all zero for PV technologies.

29 All cost assumptions for single-axis tracking systems in the following sections were based on the same two project sizes.

30 Module manufacturer annual and quarterly reports from SunPower, Trina, SunTech, First Solar, and Yingli.

Figure 14: Single-Axis Tracking Instant Costs



Source: Energy Commission.

Operating and Maintenance Costs

Photovoltaic O&M costs were generally reported to be fixed costs with no variable component. Several sources for these costs were used, including:

- *SunShot Vision Study* (U.S. DOE, 2012).
- A study by Electric Power Research Institute (EPRI, 2010).
- Bond rating reports for Topaz Solar Farm.
- An article on LCOE in *SolarPro Magazine* (Yates and Hibberd, 2012).

Fixed O&M values from these sources were averaged to find a mid case value of $28 per kilowatt year (/kW-yr.) for 2011 (in nominal dollars) (NREL JEDI Model, 2012). A high-case value of $50/kW-yr. reflects the upper end of these sources and may assume an inverter replacement reserve instead of purchasing and extended warranty (Black & Veatch, 2012). The low-case value of $20/kW-yr. reflects the lower end of these sources.

Summary of Assumptions

Table 26 summarizes the major assumptions used in estimating costs for solar PV single axis technologies. Plant characteristics are assumed to be constant over the study period. Instant costs continue to decline, as shown in **Figure 15**. O&M costs are assumed to have a 0.5 percent per year real rate of escalation, reflecting expected increases in personnel costs.

Table 26: Summary of Solar Photovoltaic Single Axis Assumptions

Plant Data	Mid Case		High Case		Low Case	
Gross Capacity (MW)	20	100	20	100	20	100
Station Service	3.0%		4.0%		2.0%	
Transformer Losses	0.5%		0.5%		0.5%	
Scheduled Outage Factor[31]	1.5%		4.0%		0.5%	
Forced Outage Rate[32]	0.0%		0.0%		0.0%	
Capacity Factor	28.0%		23.0%		31.0%	
Capacity Degradation	0.55%		1.25%		0.25%	
Interconnection Losses	1.37%	0.97%	4.56%	3.23%	0.46%	0.32%
2011 Instant Cost (AC Nominal $/kW)						
Without Ancillary Costs	$3,600	$3,600	$3,800	$3,800	$3,400	$3,400
Interconnection Costs	$398	$87	$1,004	$216	$236	$52
Land Costs	$35	$35	$91	$91	$7	$7
Licensing Costs	$31	$31	$109	$109	$15	$15
Instant Costs With Ancillary Costs	**$4,064**	**$3,753**	**$5,004**	**$4,216**	**$3,659**	**$3,475**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$28.00		$50.00		$20.00	
2011 Variable O&M Cost (Nominal $/MWh)	$0.00		$0.00		$0.00	
Insurance	0.30%		0.50%		0.25%	

Source: Energy Commission.

100 MW and 20 MW Thin-Film, Fixed-Mount Systems

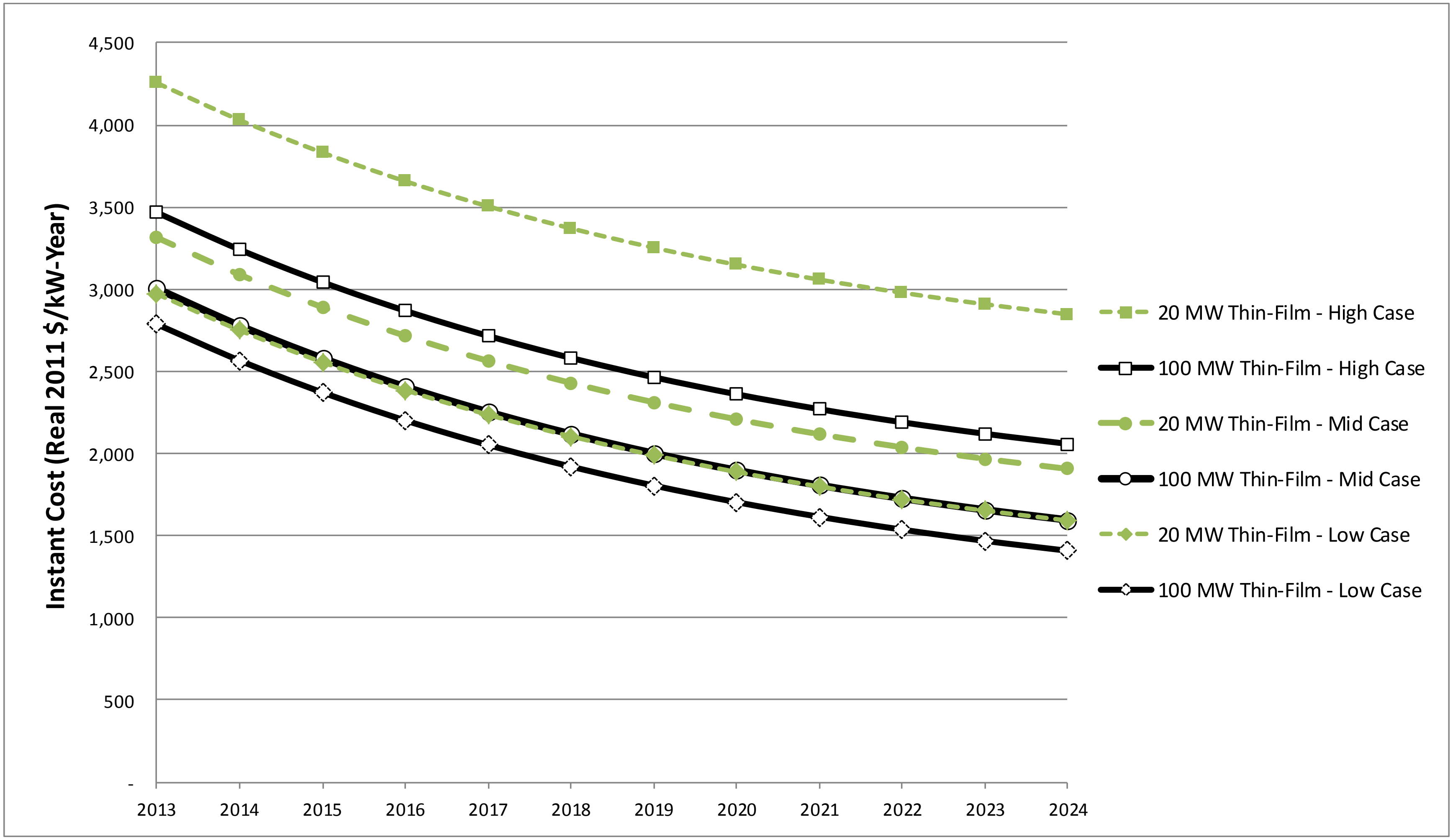
Instant Cost Trends

Instant costs for thin-film, fixed-mount PV systems are expected to decline at a steeper rate than those for single-axis PV systems. However, both expected declines are partially due to the interrelated research and production infrastructure associated with PV components. **Figure 15** shows the decline of installed costs for utility-scale, fixed-axis (thin-film) PV systems across each of the three cost cases: high, mid, and low.

31 *Scheduled outage factor* is the percentage of time when the plant is partially or fully unavailable due to planned maintenance. The COG Model uses "effective scheduled outage factor" as defined by North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS).

32 *Forced outage rate* (FOR) is the percentage of time when the plant is attempting to operate but not able to, which excludes nonoperational hours due to maintenance or curtailments. *Equivalent FOR* is used to include partial operation. The COG Model uses "equivalent FOR demand" as defined by NERC GADS.

Figure 15: 100 MW and 20 MW Thin-Film, Fixed-Mount PV Instant Cost



Source: Energy Commission.

Operating and Maintenance Costs

The costs of fixed-orientation systems were developed using the same methods and sources as single-axis tracking, with slightly different results. These costs are lower due to reduced maintenance of systems with no moving parts. O&M costs are escalated in real dollars at 0.5 percent per year.

Summary of Assumptions

Table 27 summarizes the assumptions used in estimating costs for solar PV thin-film technologies for 2011. The plant characteristics are assumed to be constant over the study period. Instant cost declines as described in **Figure 16**.

Table 27: Summary of Solar Photovoltaic Thin-Film Assumptions

Plant Data	Mid Case		High Case		Low Case	
Gross Capacity (MW)	20	100	20	100	20	100
Station Service	1.5%		2.0%		1.0%	
Transformer Losses	0.5%		0.5%		0.5%	
Scheduled Outage Factor	1.5%		4.0%		0.5%	
Forced Outage Rate	0.0%		0.0%		0.0%	
Capacity Factor	24.0%		18.0%		28.0%	
Capacity Degradation	0.95%		1.60%		0.25%	
Interconnection Losses	1.37%	0.97%	4.56%	3.23%	0.46%	0.32%
2011 Instant Cost (AC Nominal $/kW)						
Without Ancillary Costs	$3,400	$3,400	$3,600	$3,600	$3,250	$3,250
Interconnection Costs	$398	$87	$1,004	$216	$236	$52
Land Costs	$35	$35	$91	$91	$7	$7
Licensing Costs	$31	$31	$109	$109	$15	$15
Instant Costs With Ancillary Costs	**$3,864**	**$3,553**	**$4,804**	**$4,016**	**$3,509**	**$3,325**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$25.00		$50.00		$17.00	
2011 Variable O&M Cost (Nominal $/MWh)	$0.00		$0.00		$0.00	
Insurance	0.30%		0.50%		0.25%	

Source: Energy Commission.

Summary of 2013 Solar Photovoltaic Cost Data

Table 28 summarizes instant and installed costs for these solar PV technologies for 2013 (in 2013 dollars). These costs include all costs, including land and permitting costs.

Table 28: Summary of 2013 Solar Photovoltaic Instant and Installed Costs by Developer

Capital Costs Year = 2013 (Nominal Dollars)	Instant Costs ($/kW)	Installed Costs ($/kW) Merchant	IOU	POU
Mid Case				
Solar Photovoltaic (Thin-Film) 100 MW	$3,144	$3,366	$3,383	$3,322
Solar Photovoltaic (Single Axis) 100 MW	$3,660	$3,918	$3,938	$3,867
Solar Photovoltaic (Thin-Film) 20 MW	$3,469	$3,715	$3,733	$3,666
Solar Photovoltaic (Single Axis) 20 MW	$3,985	$4,267	$4,288	$4,210
High Case				
Solar Photovoltaic (Thin-Film) 100 MW	$3,629	$4,174	$4,208	$4,117
Solar Photovoltaic (Single Axis) 100 MW	$4,134	$4,755	$4,795	$4,691
Solar Photovoltaic (Thin-Film) 20 MW	$4,454	$5,123	$5,165	$5,054
Solar Photovoltaic (Single Axis) 20 MW	$4,959	$5,705	$5,752	$5,627
Low Case				
Solar Photovoltaic (Thin-Film) 100 MW	$2,917	$3,014	$3,036	$2,991
Solar Photovoltaic (Single Axis) 100 MW	$3,388	$3,501	$3,526	$3,474
Solar Photovoltaic (Thin-Film) 20 MW	$3,110	$3,213	$3,236	$3,188
Solar Photovoltaic (Single Axis) 20 MW	$3,581	$3,700	$3,726	$3,671

Source: Energy Commission.

Table 29 summarizes O&M costs for 2013 (in nominal dollars).

Table 29: Summary of Solar Photovoltaic Operating and Maintenance Costs

O&M Costs Year = 2013 (Nominal Dollars)	Fixed O&M ($/kW-Yr.)	Variable O&M ($/MWh)	Total O&M ($/kW-Yr.)	Total O&M ($/MWh)
Mid Case				
Solar Photovoltaic (Thin-Film) 100 MW	$26.43	$0.00	$26.43	$12.57
Solar Photovoltaic (Single Axis) 100 MW	$29.60	$0.00	$29.60	$12.07
Solar Photovoltaic (Thin-Film) 20 MW	$26.43	$0.00	$26.43	$12.57
Solar Photovoltaic (Single Axis) 20 MW	$29.60	$0.00	$29.60	$12.07
High Case				
Solar Photovoltaic (Thin-Film) 100 MW	$52.86	$0.00	$52.86	$33.53
Solar Photovoltaic (Single Axis) 100 MW	$52.86	$0.00	$52.86	$26.24
Solar Photovoltaic (Thin-Film) 20 MW	$52.86	$0.00	$52.86	$33.53
Solar Photovoltaic (Single Axis) 20 MW	$52.86	$0.00	$52.86	$26.24
Low Case				
Solar Photovoltaic (Thin-Film) 100 MW	$17.97	$0.00	$17.97	$7.33
Solar Photovoltaic (Single Axis) 100 MW	$21.15	$0.00	$21.15	$7.79
Solar Photovoltaic (Thin-Film) 20 MW	$17.97	$0.00	$17.97	$7.33
Solar Photovoltaic (Single Axis) 20 MW	$21.15	$0.00	$21.15	$7.79

Source: Energy Commission.

CHAPTER 5: Solar Thermal Technologies

Overview

Among solar thermal facilities, the parabolic trough and power tower designs are considered to be the most viable in the near future. In addition, these technologies are capable of using thermal storage technologies to extend hours of operation beyond dusk when PV technologies would stop producing. For both technologies, 100 MW installations without storage and with 6 hours of storage were explored. In addition, for solar power tower designs, an 11-hour storage option was researched to help provide estimates appropriate to the direction some developers have taken recently, maximizing the storage capacity of these installations.

Technology Description

Solar thermal plants, also known as *concentrating solar power plants* (CSP), collect and convert solar energy into power using conventional steam turbines. There are two predominant commercial embodiments of solar thermal plants—parabolic troughs and solar towers—both of which collect sunlight over large "solar fields." The captured solar energy generates heat that is transferred to a working fluid (such as pressurized oil). The working fluid is used to generate steam, which is routed through steam turbines to generate electricity. Parabolic trough solar plants use linear parabolic collectors to focus the sun's rays. These collectors rotate to concentrate direct sunlight onto a pipe located along the focal line of the reflective surfaces. Solar tower plants are surrounded by a field of reflectors (known as *heliostats*) that move to focus direct sunlight onto a receiver atop a central tower. There are about a half-dozen commercial tower plants operational worldwide.[33]

Both trough and tower CSP plants may include thermal energy storage (TES). TES stores the working fluid at high temperatures and allows the plant operator to have some control over when electricity is generated, thereby increasing the plant's dispatchability. Energy collected earlier in the day can be drawn from storage to generate additional power in the afternoon, even as solar input declines. TES is an important CSP component since it adds both significant additional capital costs and significant expansion of the operational profile, greatly reducing the levelized cost of energy. However, few existing commercial CSP plants

33 Ibid.

include TES. Available CSP plant cost and performance data reflect trough plants both with and without TES. Tower plants are primarily described with TES.

Trends and Analysis

Solar thermal technologies represent a growing share of the total solar portfolio under construction in the United States. While solar thermal plants were featured prominently in California, projects begun under the 2009 American Recovery and Reinvestment Act have declined as those funds are no longer available. This reduction tends to slow the learning process and therefore makes cost declines more gradual than those experienced by the solar photovoltaic industry. However, there is strong interest among renewable developers to find ways to capture the maximum value of solar energy; thermal technologies with storage allow the plant operator to participate in the electricity marketplace in the evening hours after solar photovoltaic plants are no longer generating.

The Energy Commission engaged Navigant and Itron to survey the available data, extract the relevant information, and adjust nationwide estimates into California-specific values. About 50 trough plants are operational worldwide as of 2012 (NREL, Operational Plants, 2012).

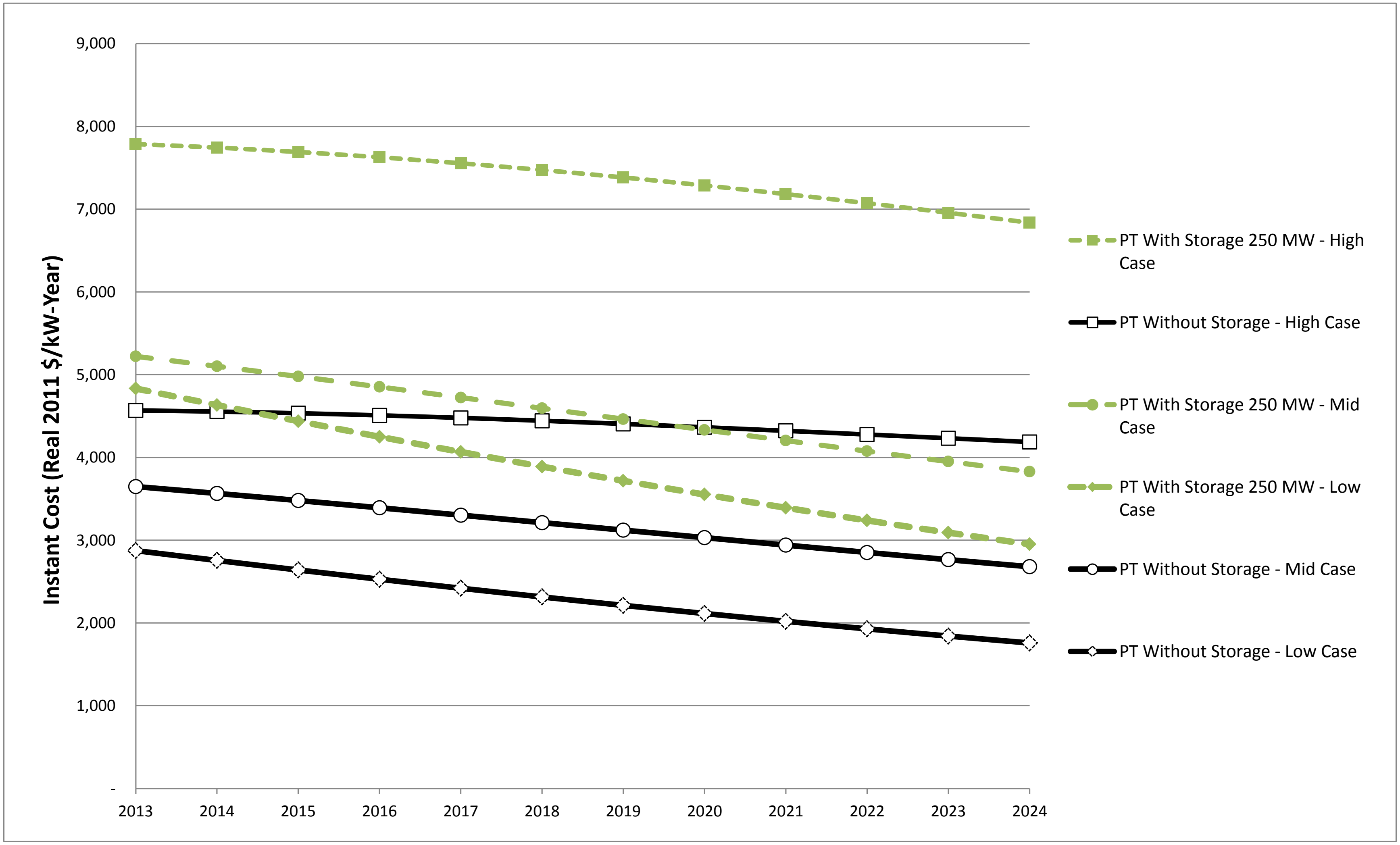
250 MW Parabolic Trough Solar Thermal (With and Without Storage)

Parabolic trough plants are modeled both with six hours of TES and without TES. High, mid, and low cases are shown for both configurations.

Instant Cost Trends

Figure 16 shows the cost trends for parabolic instant costs. The costs from these projects are not expected to vary much until this wave of construction is complete. For projects after 2015, Navigant derived a rough average of projected costs from a number of studies, including Black & Veatch, 2012, AT Kearney, 2010, U.S. EIA, 2010, and U.S. DOE, 2012.

Figure 16: 250 MW Solar Parabolic Trough Instant Cost—With and Without Storage



Source: Energy Commission.

Operating and Maintenance Costs

The 354 MW Solar Energy Generating Systems (SEGS) parabolic trough solar thermal plants have been operational in California since 1984. While there has been some construction of parabolic trough plants since the SEGS plants became operational, these are relatively few, and the public data on O&M costs are similarly limited. Therefore, the SEGS costs are used as the best proxy for these costs, with little change since the last COG update in 2009.

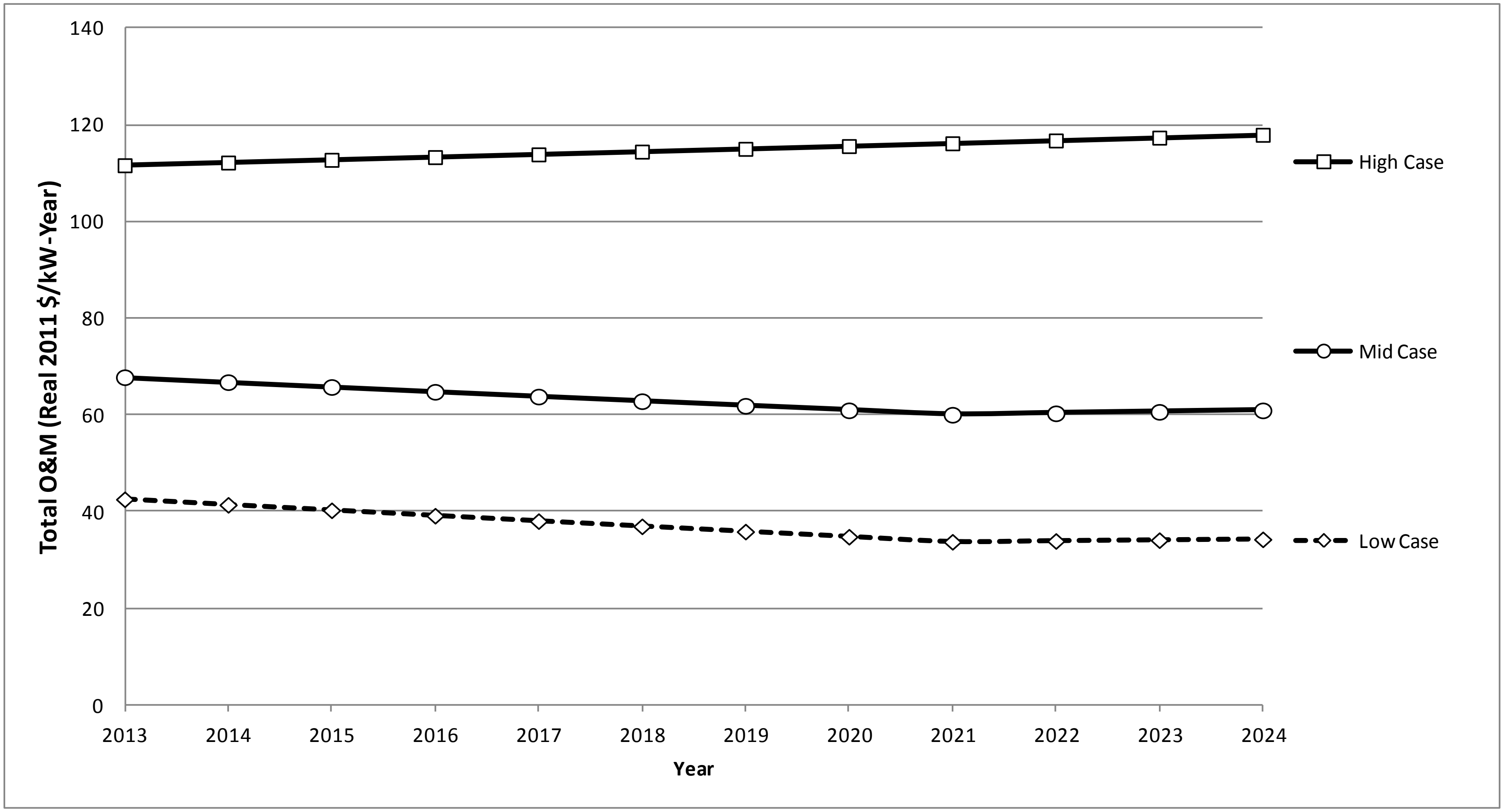
These O&M costs are expected decline over time. With the recent resurgence of CSP technology and further experience with operations, a 11.5 percent O&M cost reduction over the next eight years (2013 – 2021) seems reasonable, corresponding to half of the improvements experienced by the SEGS plants (Cohen et al., 1999). Beyond Year 8, this study assumes O&M costs escalate at 0.5 percent annual real increase to account for increases in personnel costs. The sum of these two effects is shown in **Figure 17** and **Figure 18**.

As expected, O&M costs for solar parabolic troughs are significantly lower when installed without TES since these storage systems require extensive maintenance and upkeep to maintain efficiency and proper operation.

Summary of Assumptions

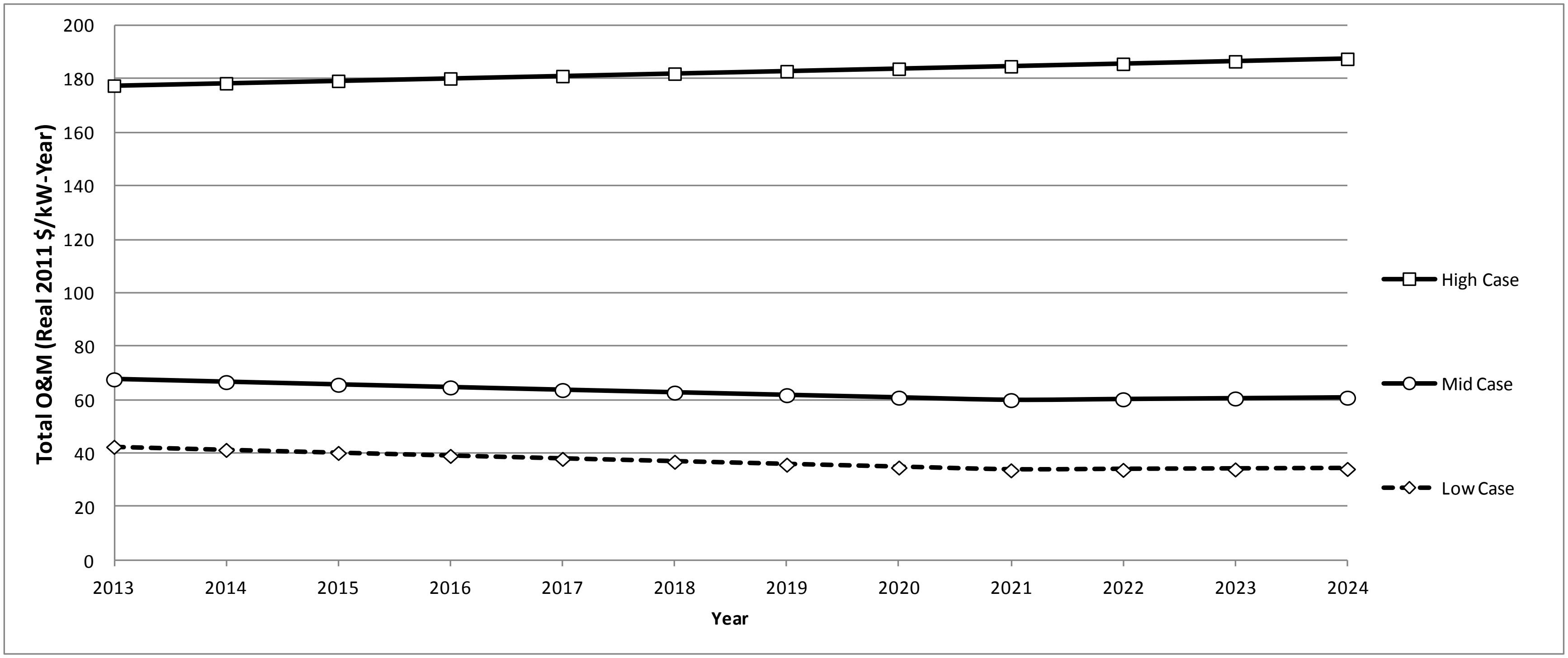
Table 30 summarizes the major plant characteristics and costs for the solar parabolic technologies, with and without storage. Plant characteristics are assumed to be constant over the study period. Instant costs and O&M costs decline as shown in **Figure 19**, **Figure 20**, and **Figure 21**.

Figure 17: 250 MW Solar Parabolic Trough Without Storage—Total Operating and Maintenance Costs (Real 2011 $/kW-yr.)



Source: Energy Commission.

Figure 18: 250 MW Solar Parabolic Trough With Storage—Total Operating and Maintenance Costs (Real 2011$/kW-yr.)



Source: Energy Commission.

Table 30: Summary of Solar Parabolic Plant Characteristics and Costs—With and Without Storage

Plant Data	Mid Case		High Case		Low Case	
	W/O Storage	With Storage	W/O Storage	With Storage	W/O Storage	With Storage
Gross Capacity (MW)	250	250	250	250	250	250
Station Service	10.71%		15.00%		9.00%	
Transformer Losses	0.5%		0.5%		0.5%	
Scheduled Outage Factor	2.00%		4.00%		0.00%	
Forced Outage Rate	6.00%		8.00%		1.00%	
Capacity Factor	26.5%	43.0%	20.0%	41.0%	29.0%	45.0%
Capacity Degradation (%/Year)	0.50%		1.40%		0.25%	
2011 Instant Cost (AC Nominal $/kW)						
Without Ancillary Costs	$3,608	$5,244	$4,095	$7,411	$3,017	$5,143
Interconnection Costs	$122	$122	$270	$270	$77	$77
Land Costs	$35	$35	$91	$91	$7	$7
Licensing Costs	$31	$31	$109	$109	$15	$15
Instant Costs With Ancillary Costs	**$3,796**	**$5,432**	**$4,565**	**$7,881**	**$3,116**	**$5,242**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$67.11	$67.11	$93.00	140.00	$42.11	42.11
2011 Variable O&M Cost (Nominal $/MWh)	$0.00	$0.00	$10.00	$10.00	$0.00	$0.00
2011 Total O&M Cost (Nominal $/MWh)	$28.91	$17.82	$63.08	$48.98	$16.58	$10.68
2011 Total O&M Cost (Nominal $/kW-yr.)	$67.11	$67.11	$110.52	$175.92	$42.11	$42.11
Insurance	0.30%		0.50%		0.25%	

Source: Energy Commission.

100 MW Solar Thermal Power Tower

Costs for solar thermal power towers were based on a 100 MW-sized project. Solar thermal power tower plants are modeled with and without thermal storage, similar to the parabolic trough solar thermal case. The storage capacity allows the renewable plant to operate for up to 11 hours after the sun goes down so it can better match peak system loads, which tend to be from 4:00 p.m. to 7:00 p.m. as residential customers come home from work.

Instant Cost Trends

The mid case power tower without storage is based on information from the $1.6 billion U.S. DOE loan guarantee to the Ivanpah project.[34] The instant cost is back-calculated using the installed cost. With few other commercial solar power tower projects without storage, the high case was taken to be 20 percent higher than the mid case, and the low case 10 percent lower than the mid case, reflecting typical contingencies on construction projects of this nature.

Figure 19 shows cost projections for the no storage case, which is similar in shape to parabolic trough. Costs from project to project are not expected to vary much until this wave of construction is complete. For projects after 2015, Navigant estimated a rough average of projected costs from a number of studies—Black & Veatch 2012, AT Kearney 2010, U.S. EIA, and U.S. DOE. **Figure 20** shows the tower case with 6 hours storage, and **Figure 21** shows the 11 hours storage case. **Figure 22** compares the mid case instant costs for the same with and without storage cases.

Initial costs are derived from public DOE loan guarantee data[35] and recent cost studies, as these appear to be the most accurate public costs available at this time. The mid-cost case for the power tower with storage is based on a recent study conducted by Black & Veatch for NREL (Black & Veatch, 2012). The high case is based on the DOE loan guarantee to the Crescent Dunes Solar Energy Project near Tonopah, Nevada.[36] The low case is based on the Power Tower Solar Advisory Model estimates, which are arrived at through a consensus process with industry (System Advisor Model, 2012).

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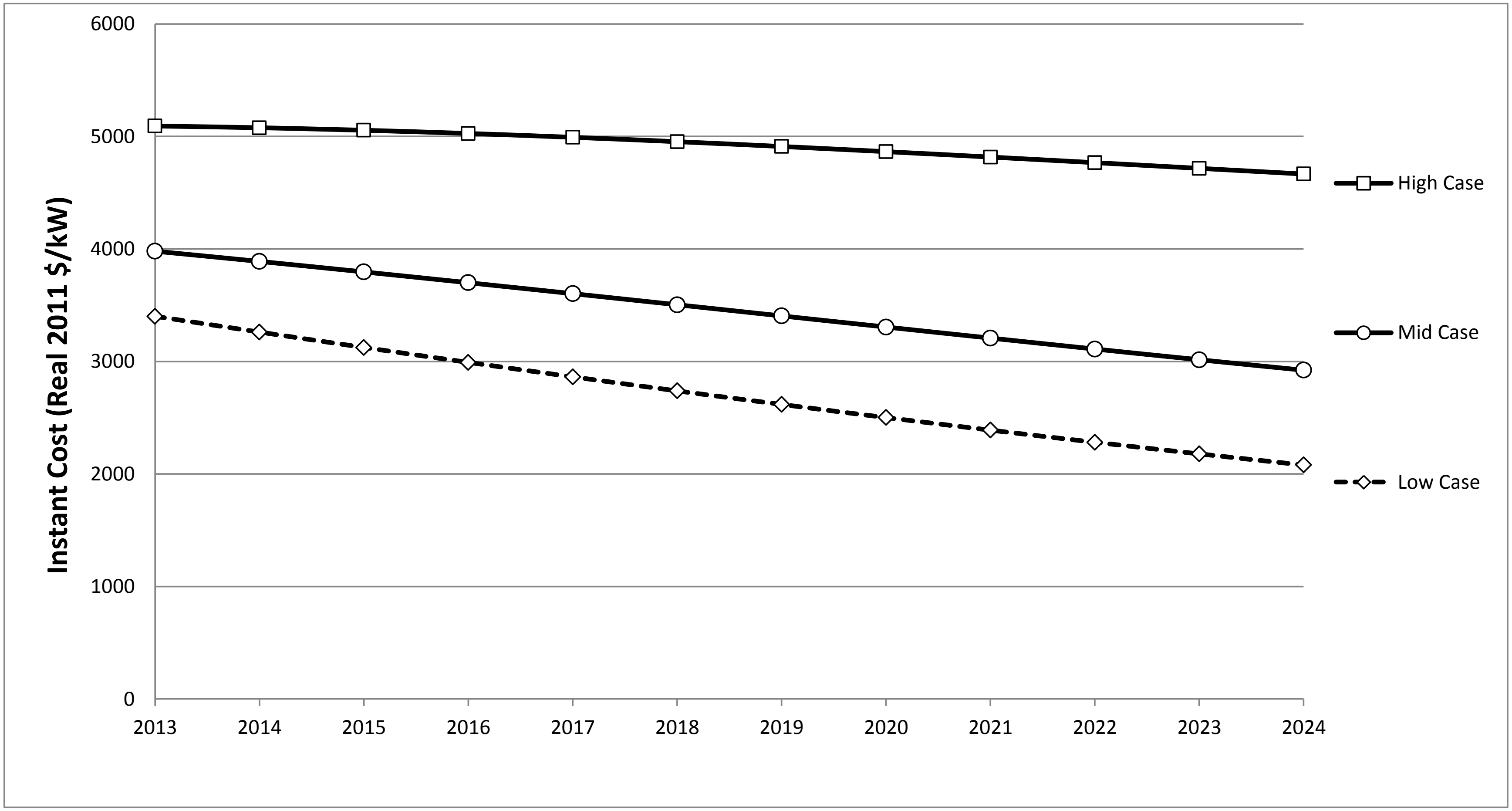
34 The Ivanpah Solar Electric Generating System project in the California Mojave Desert is for 370 MW net but consists of three towers, each accounting for one-third of its total capacity, or 120 MW, which is close to the nominal 100 MW plant size. The nominal plant size matches the 100 MW most discussed in the literature for easier comparison. As more projects are built, nominal plant block sizes will become clearer.

35 "DOE-Loan Programs" see <https://lpo.energy.gov/?projects=abengoa-solar-inc> and "NREL Concentrating Solar Power Projects Home Page1" see <http://www.nrel.gov/csp/solarpaces>.

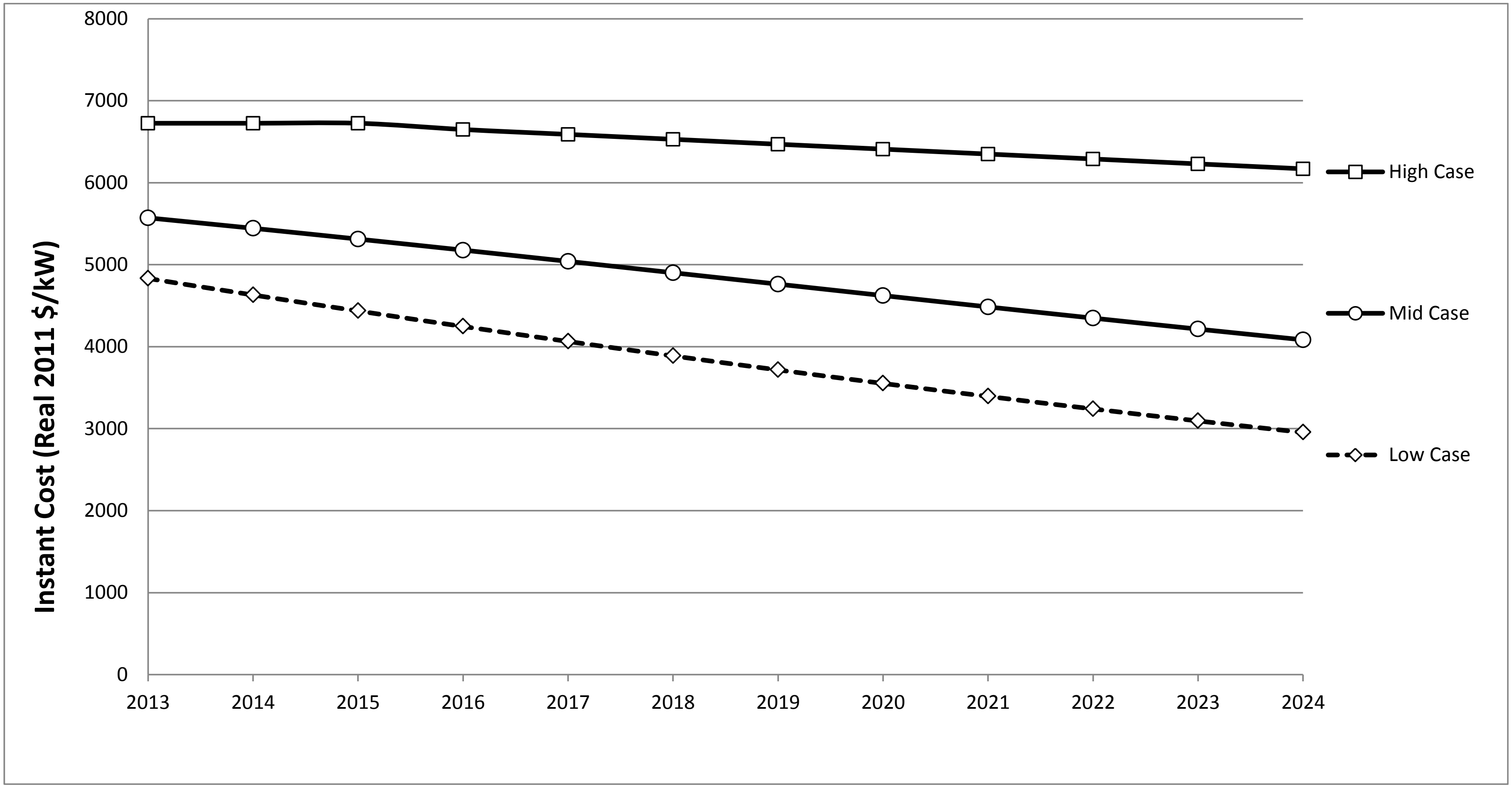
36 737 million/110 MW net capacity = 6,700 $/kW in debt. 6,700 * 1.25 = 8,380 $/kW total.

Figure 19: 100 MW Solar Power Tower Without Storage Instant Costs—Mid, High, and Low Cases



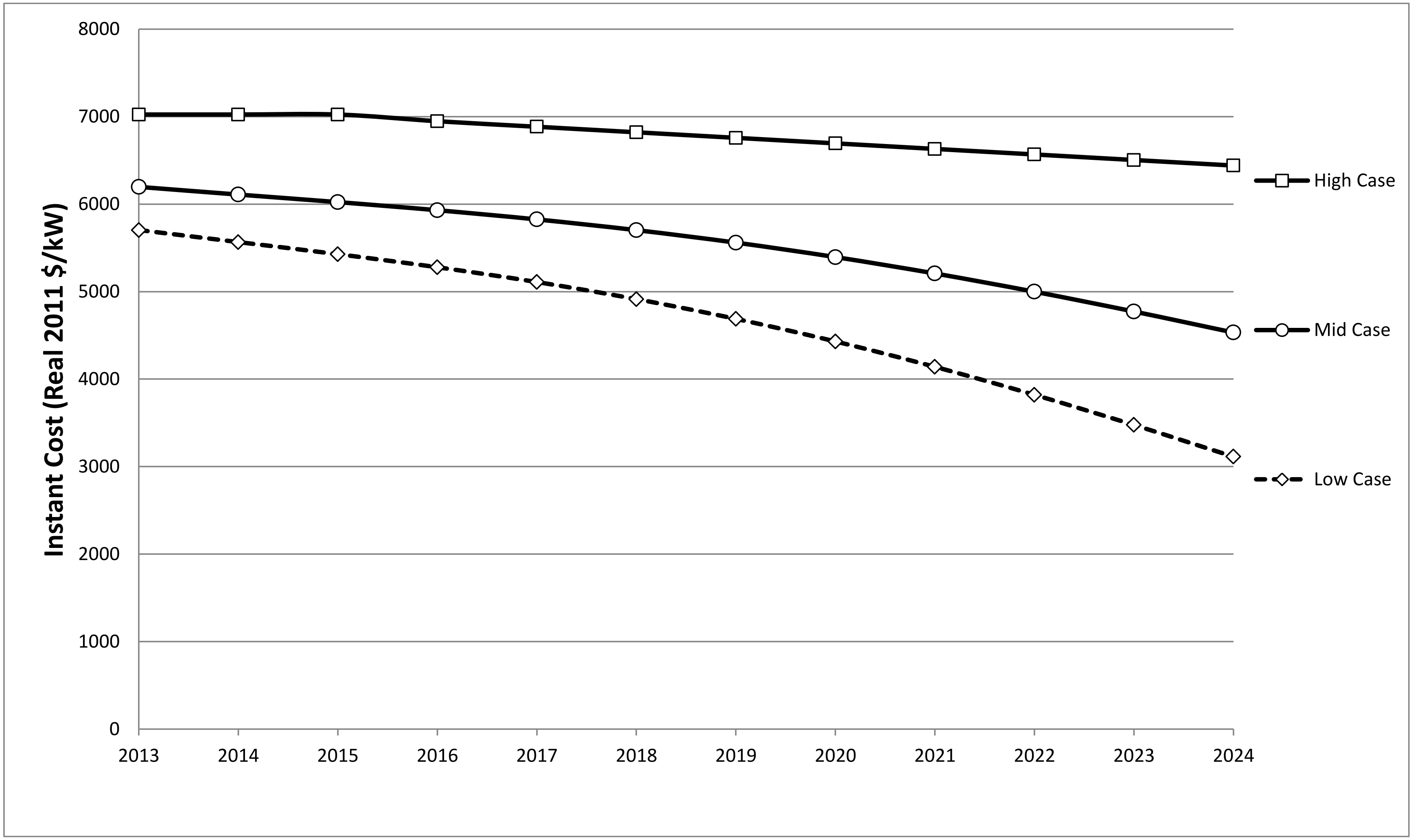
Source: Energy Commission.

Figure 20: 100 MW Solar Power Tower With Six Hours Storage Instant Costs—Mid, High, and Low Cases



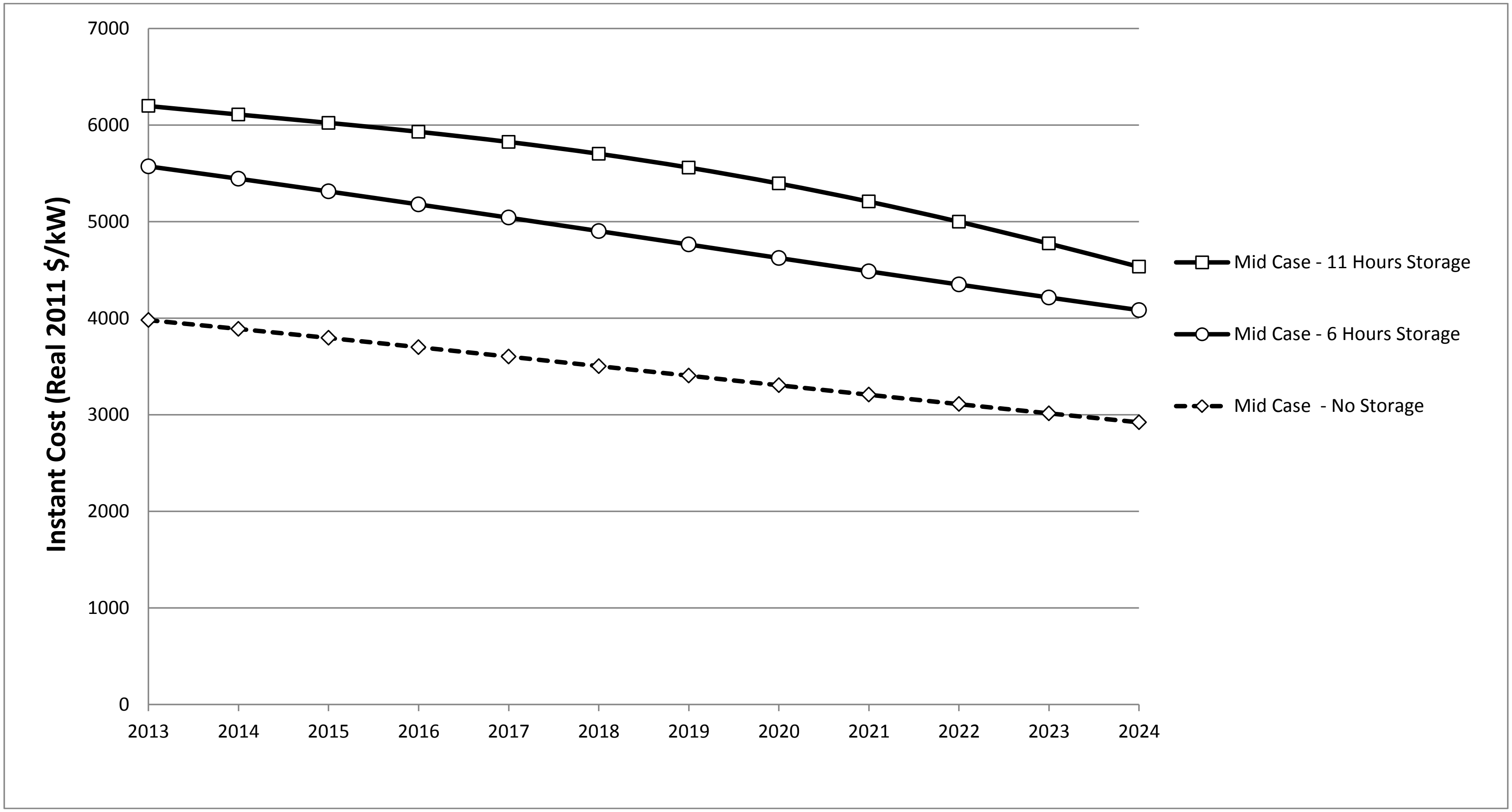
Source: Energy Commission.

Figure 21: 100 MW Solar Power Tower With 11 Hours Storage Instant Costs—Mid, High, and Low Cases



Source: Energy Commission.

Figure 22: 100 MW Solar Power Tower Instant Costs—Mid Cases



Source: Energy Commission.

Operations and Maintenance Costs

For solar power tower plants, which have recently emerged and become commercially available, limits the amount of public data readily available. The best estimates are provided by a recent Sandia National Laboratories report (Kolb, et al., 2011), from which the consensus low was used as the mid case.

Similar to solar trough plants, O&M costs are expected to decline as operational proficiency improves. A 28 percent cost reduction is expected over the next eight years (2013 – 2021), corresponding to the improvement experienced by the SEGS plants, because power tower technology is not yet mature.[37] After 2021, the Energy Commission's 0.5 percent annual increase in costs is assumed to account for personnel costs. The sum of these two effects is shown in

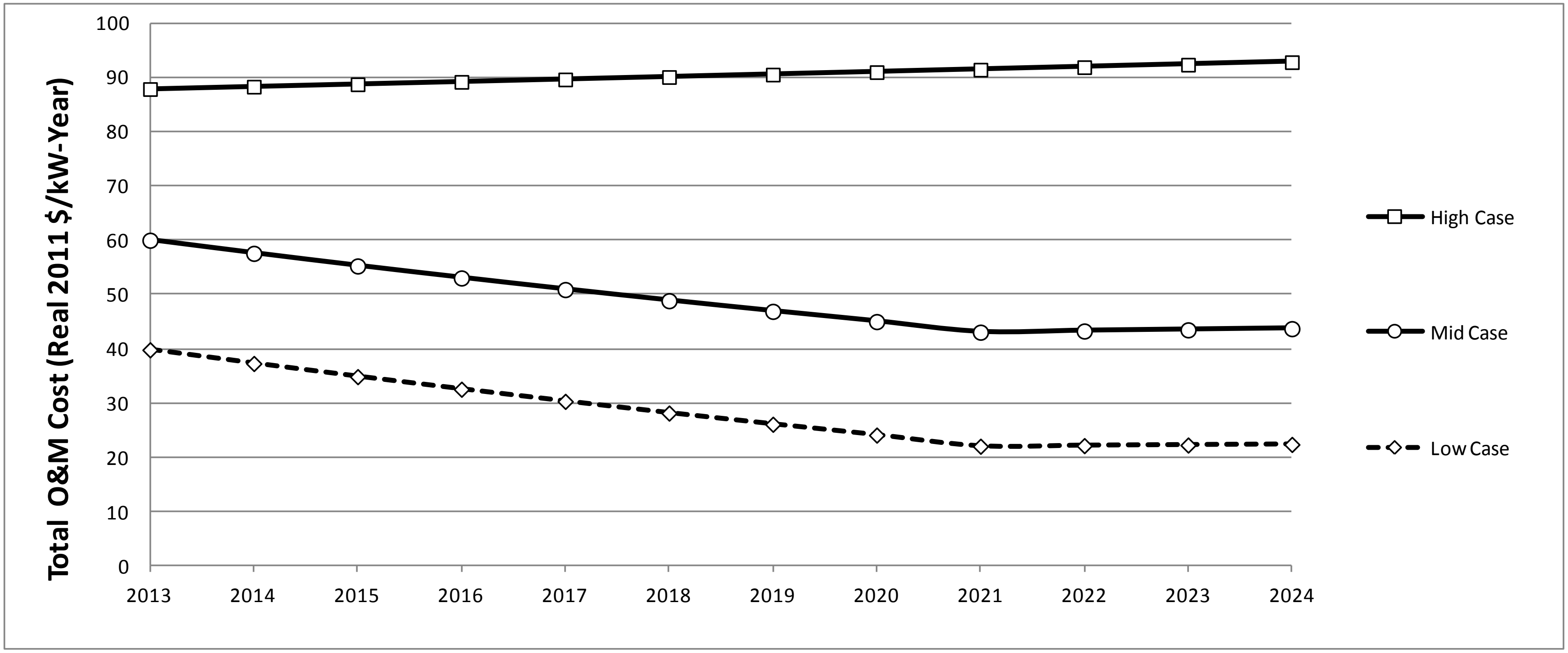
Figure 23. **Figure 24** shows O&M costs for units with 6- and 11-hour storage.

Summary of Assumptions

Table 31 summarizes plant characteristics and merchant costs for the solar tower technologies. Plant characteristics are assumed to be constant from 2013 – 2024. Instant costs vary as described above. O&M costs are assumed to have a real escalation rate of 0.5 percent per year.

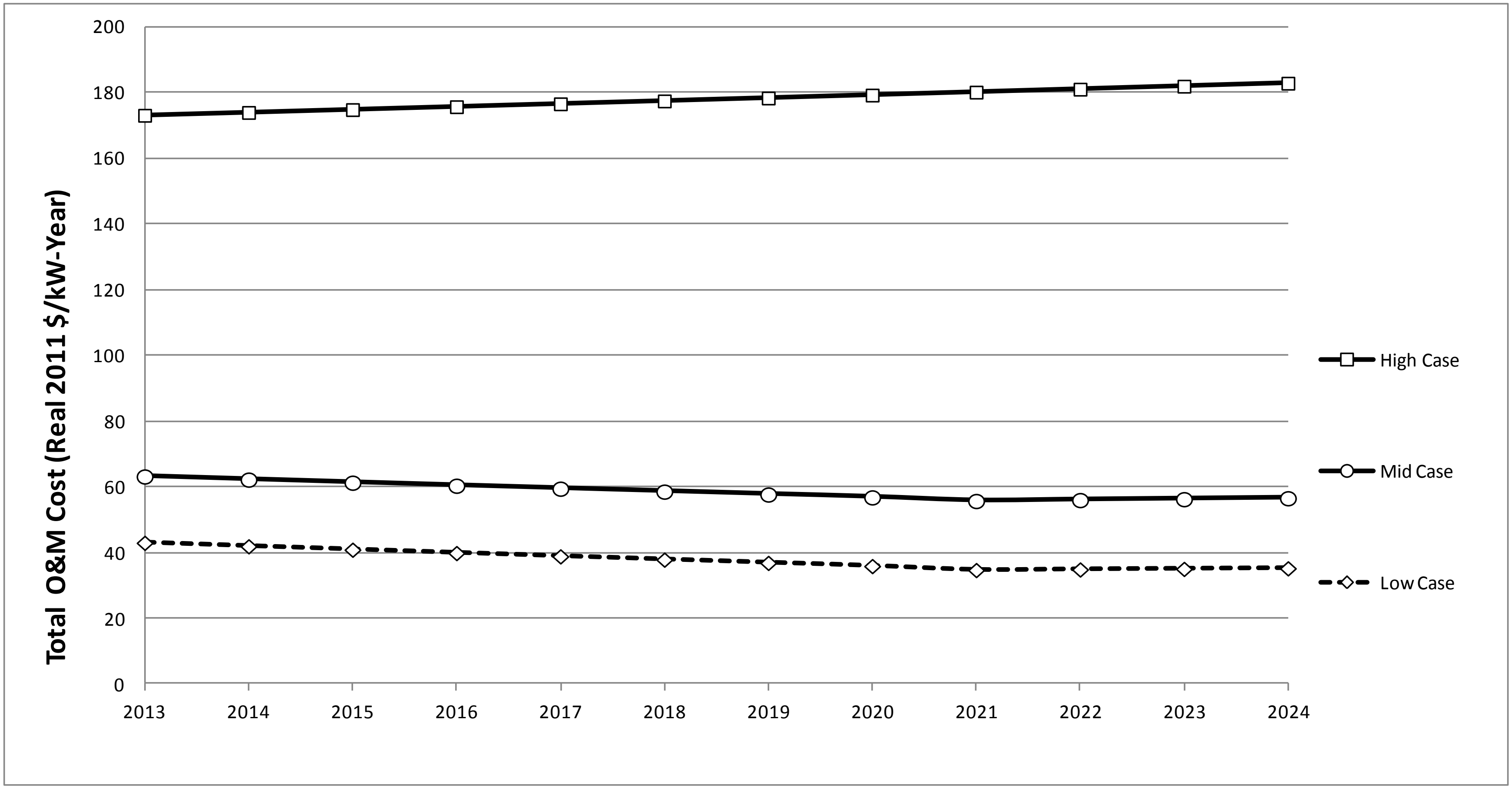
37 Based on work done by Navigant for the Energy Commission.

Figure 23: Solar Power Tower Without Storage—Total Operating and Maintenance Costs



Source: Energy Commission.

Figure 24: Solar Tower With Storage (6-Hour and 11-Hour) Total Operating and Maintenance Cost



Source: Energy Commission.

Table 31: Plant Characteristics and Costs for Solar Tower Technologies

Plant Data	Mid Cost			High Cost			Low Cost		
	W/O Storage	W/6 Hrs. Storage	W/11 Hrs. Storage	W/O Storage	W/6 Hrs. Storage	W/11 Hrs. Storage	W/O Storage	W/6 Hrs. Storage	W/11 Hrs. Storage
Gross Capacity (MW)	100	100	100	100	100	100	100	100	100
Station Service	12.00%	12.00%	12.50%	13.00%	13.00%	13.00%	7.00%	10.00%	10.00%
Transformer Losses	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Capacity Factor	2.00%	2.00%	2.00%	4.00%	4.00%	4.00%	0.00%	0.00%	0.00%
Forced Outage Rate	6.00%	6.00%	6.00%	8.00%	8.00%	8.00%	1.00%	1.00%	1.00%
Scheduled Outage Factor	31.00%	40.00%	56.00%	30.00%	36.00%	52.30%	32.00%	48.20%	62.00%
Capacity Degradation (%/Year)	0.50%			1.40%			0.25%		
2011 Instant Cost (Nominal $/kW)									
Without Ancillary Costs	$3,988	$5,646	$6,525	$4,674	$6,310	$6,608	$3,615	$5,168	$6,108
Interconnection Costs	$87	$87	$87	$216	$216	$216	$52	$52	$52
Land Costs	$35	$35	$35	$91	$91	$91	$7	$7	$7
Licensing Costs	$31	$31	$31	$109	$109	$109	$15	$15	$15
Instant Costs With Ancillary Costs	**$4,141**	**$5,799**	**$6,678**	**$5,090**	**$6,726**	**$7,024**	**$3,689**	**$5,242**	**$6,182**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$65.14	$65.23	$65.23	$87.00	$140.00	$140.00	$45.14	$45.23	$45.23
2011 Variable O&M Cost (Nominal $/MWh)	$0.00	$0.00	$0.00	$0.00	$10.00	$10.00	$0.00	$0.00	$0.00
2011 Total O&M Cost (Nominal $/MWh)	$23.99	$18.62	$13.30	$33.11	$54.39	$40.56	$16.10	$10.71	$8.33
2011 Total O&M (Nominal $/kW-yr.)	$65.14	$65.23	$65.23	$87.00	$171.54	$185.81	$45.14	$45.23	$45.23
Insurance (%/Year)	0.30%			0.50%			0.25%		

Source: Energy Commission.

Summary of 2013 Solar Thermal Costs

Table 32 summarizes 2013 instant and the corresponding installed costs by developer. Installed cost is the instant cost plus the cost of financing the plant during construction, loan fees, and insurance.

Table 32: Summary of 2013 Instant and Installed Costs by Developer

Capital Costs Year = 2013 (Nominal Dollars)	Instant Costs ($/kW)	Installed Costs ($/kW)		
		Merchant	IOU	POU
Mid Case				
Solar Parabolic Trough W/O Storage 250 MW	$3,819	$4,259	$4,301	$4,147
Solar Parabolic Trough With Storage 250 MW	$5,465	$6,094	$6,155	$5,935
Solar Power Tower W/O Storage 100 MW	$4,166	$4,646	$4,692	$4,524
Solar Power Tower With Storage 100 MW 6 HRs	$5,833	$6,504	$6,569	$6,334
Solar Power Tower With Storage 100 MW 11 HRs	$6,487	$7,234	$7,305	$7,044
High Case				
Solar Parabolic Trough W/O Storage 250 MW	$4,781	$5,601	$5,659	$5,506
Solar Parabolic Trough With Storage 250 MW	$8,150	$9,547	$9,647	$9,386
Solar Power Tower W/O Storage 100 MW	$5,331	$6,245	$6,310	$6,139
Solar Power Tower With Storage 100 MW 6 HRs	$7,041	$8,247	$8,333	$8,108
Solar Power Tower With Storage 100 MW 11 HRs	$7,353	$8,613	$8,702	$8,467
Low Case				
Solar Parabolic Trough W/O Storage 250 MW	$3,009	$3,144	$3,178	$3,108
Solar Parabolic Trough With Storage 250 MW	$5,059	$5,286	$5,343	$5,225
Solar Power Tower W/O Storage 100 MW	$3,561	$3,720	$3,760	$3,678
Solar Power Tower With Storage 100 MW 6 HRs	$5,058	$5,285	$5,342	$5,224
Solar Power Tower With Storage 100 MW 11 HRs	$5,971	$6,239	$6,306	$6,167

Source: Energy Commission.

Table 33 summarizes O&M costs for 2013 (in nominal dollars).

Table 33: Summary of 2013 Operation and Maintenance Costs

O&M Costs	Fixed O&M ($/kW-Yr.)	Variable O&M ($/MWh)	Total O&M	
Year = 2013 (Nominal Dollars)			($/kW-Yr.)	($/MWh)
Mid Case				
Solar Parabolic Trough W/O Storage 250 MW	$70.95	$0.00	$70.95	$30.56
Solar Parabolic Trough With Storage 250 MW	$70.95	$0.00	$70.95	$18.84
Solar Power Tower W/O Storage 100 MW	$62.81	$0.00	$62.81	$23.13
Solar Power Tower With Storage 100 MW 6 HRs	$66.25	$0.00	$66.25	$18.91
Solar Power Tower With Storage 100 MW 11 HRs	$66.25	$0.00	$66.25	$13.50
High Case				
Solar Parabolic Trough W/O Storage 250 MW	$98.33	$10.57	$116.85	$66.69
Solar Parabolic Trough With Storage 250 MW	$148.02	$10.57	$185.99	$51.78
Solar Power Tower W/O Storage 100 MW	$91.98	$0.00	$91.98	$35.00
Solar Power Tower With Storage 100 MW 6 HRs	$148.02	$10.57	$181.36	$57.51
Solar Power Tower With Storage 100 MW 11 HRs	$148.02	$10.57	$196.46	$42.88
Low Case				
Solar Parabolic Trough W/O Storage 250 MW	$44.52	$0.00	$44.52	$17.53
Solar Parabolic Trough With Storage 250 MW	$44.52	$0.00	$44.52	$11.29
Solar Power Tower W/O Storage 100 MW	$41.67	$0.00	$41.67	$14.86
Solar Power Tower With Storage 100 MW 6 HRs	$45.10	$0.00	$45.10	$10.68
Solar Power Tower With Storage 100 MW 11 HRs	$45.10	$0.00	$45.10	$8.30

Source: Energy Commission.

CHAPTER 6:
Wind Technology

Overview

Wind generation technologies, like solar, have been the subject of much study and discussion over the last several years. The following presents assumptions and estimates of California-specific lifetime costs of building and operating wind generation resources built between 2013 and 2024 for wind speed Classes 3 and 4. These assumptions and estimates are derived from a review of the literature and collation of the relevant values.

Technology Description

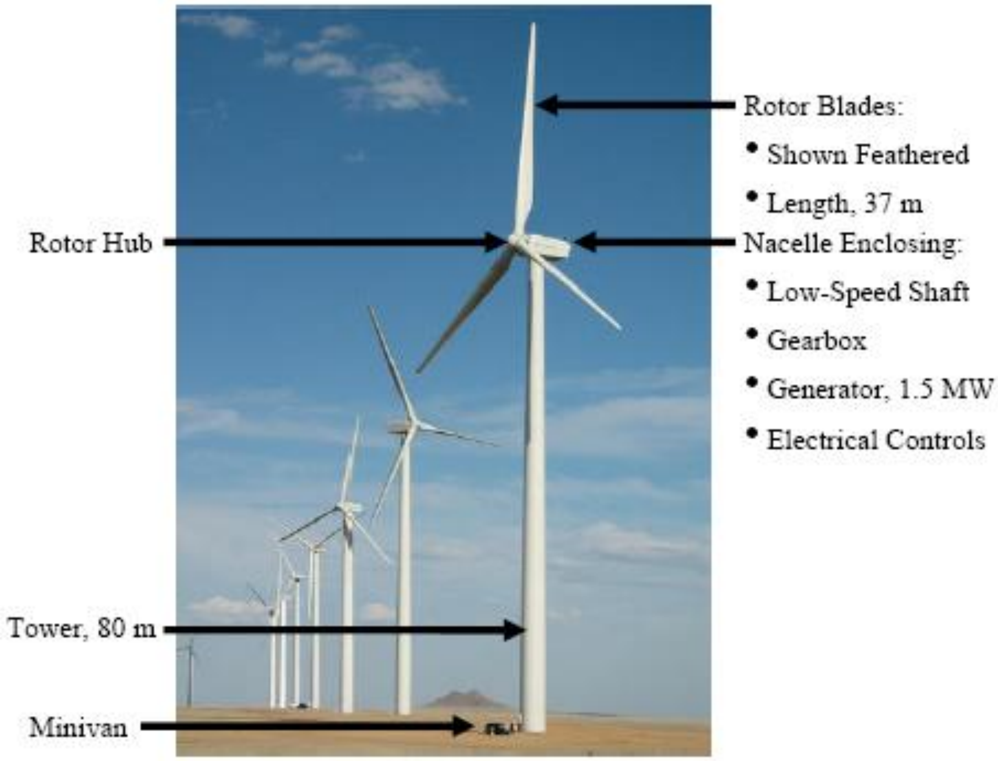
A wind energy system transforms the kinetic energy of the wind into electrical energy that can be harnessed for practical use. The main components of a wind turbine are:

- A rotor, or blades, which convert the energy of the wind into rotational shaft energy.
- A nacelle (enclosure) containing a drivetrain, usually including a gearbox and a generator.
- A tower to support the rotor and drivetrain.
- Electronic equipment, such as controls, electrical cables, ground support equipment, and interconnection equipment.

Some wind turbines use direct-drive generators and do not need a gearbox. Maintaining a gearbox can be a critical cost component.

Typical wind power plant units today consist of 1.5 MW to 2.5 MW turbines atop 80 meter towers, as shown in **Figure 25**. Wind farms can range in size from a few MW to hundreds of MW in capacity, composed of dozens of turbines. Wind power plants are *modular*, which means they consist of small individual modules (the turbines) and can easily be made larger or smaller, as needed. Turbines can be added as electricity demand grows. A 50 MW wind farm can be completed in one to two years (O'Connell, et al., 2007). Most of that time is needed for measuring the wind and obtaining construction permits. The wind farm itself can be built in less than six months (Reategui and Tegen, 2008).

Figure 25: A Modern 1.5 MW Wind Turbine Installed in a Wind Power Plant



Source: U.S. DOE, Energy Efficiency and Renewable Energy, (U.S. DOE and EERE, 2008).

Regions

Wind resources are ranked by the strength and consistency of the wind in a particular region. **Table 34** shows wind resources classified by a combination of *wind power density*[38] and wind speed as measured at two different heights. Some areas of California have good (Class 3 and 4) to excellent (Class 5, 6, and 7) wind resources. However, virtually all of the higher speed resources are offshore. Offshore wind construction has not occurred in California because offshore wind often engenders local opposition, since many consider such wind facilities unsightly, and because accessing offshore resources can be cost-prohibitive. These obstacles are expected to continue for the foreseeable future; therefore, offshore wind is not included in this assessment. The majority of the most consistent (Class 4 and 5) sites in California already have extensive development. Future development is

38 *Wind power density* is a measure of the availability of power (measured in watts) on average in a location per square meter of space.

most likely to occur at Class 3 sites. This analysis focuses on Class 3 and Class 4, reflecting resource potential in California.

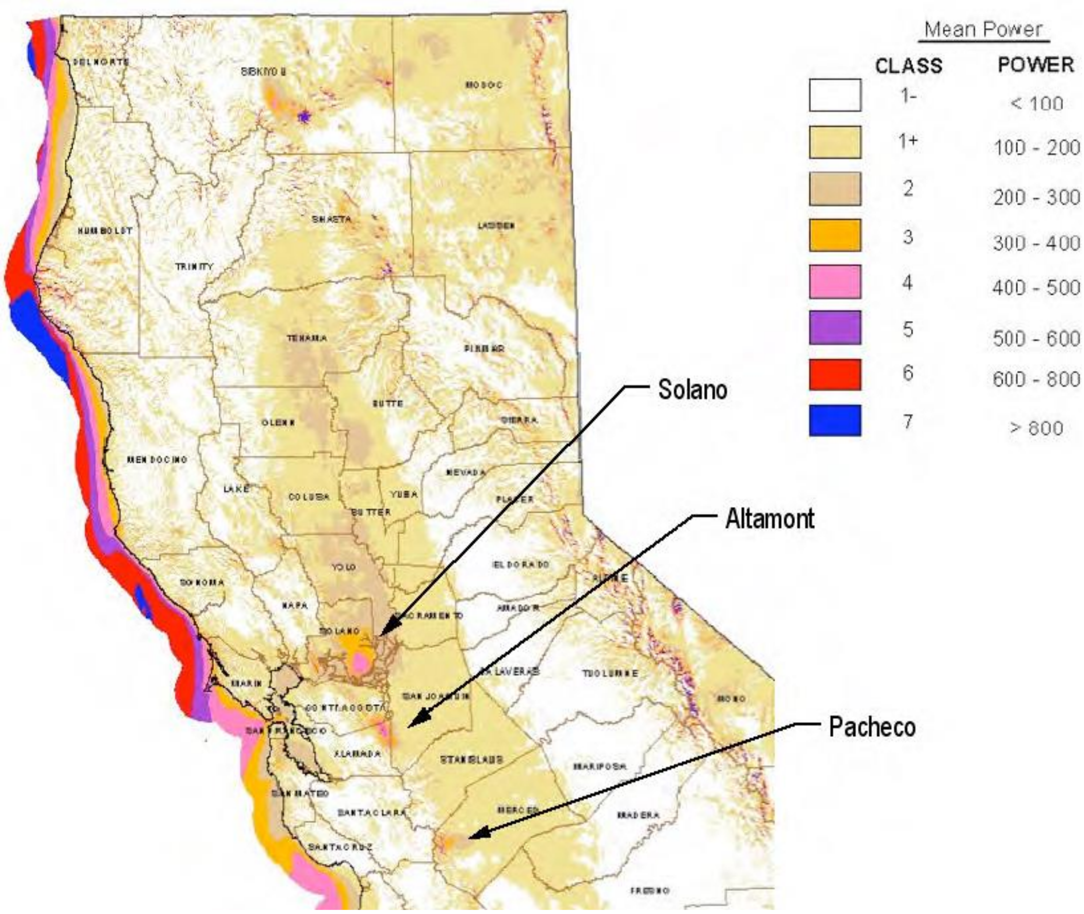
Table 34: Classes of Wind Power Density

Wind Power Class	At 10 Meters High		At 50 Meters High	
	Wind Power Density (W/m2)	Wind Speed m/s (mph)	Wind Power Density (W/m^2)	Wind Speed m/s (mph)
1	0-100	0/4.4 (9.8)	0 – 200	0 – 5.6 (12.5)
2	100 – 150	4.4 (9.8)/5.11 (11.5)	200 – 300	5.6 (12.5)/6.4 (14.3)
3	150 – 200	5.1 (11.5)/5.6 (12.5)	300 – 400	6.4 (14.3)/7.0 (15.7)
4	200 – 250	5.6 (12.5)/6.0 (13.4)	400 – 500	7.0 (15.7)/(16.8)
5	250 – 300	6.0 (13.4)/6.4 (14.3)	500 – 600	7.5 (16.8)/8.0 (17.9)
6	300 – 400	6.4 (14.3)/7.0 (15.7)	600 – 800	8.0 (17.9)/8.8 (19.7)
7	>400	>7.0 (15.7)	>800	>8.8 (19.7)

Source: NREL, see rredc.nrel.gov/wind/pubs/atlas/tables/1-1T.html.

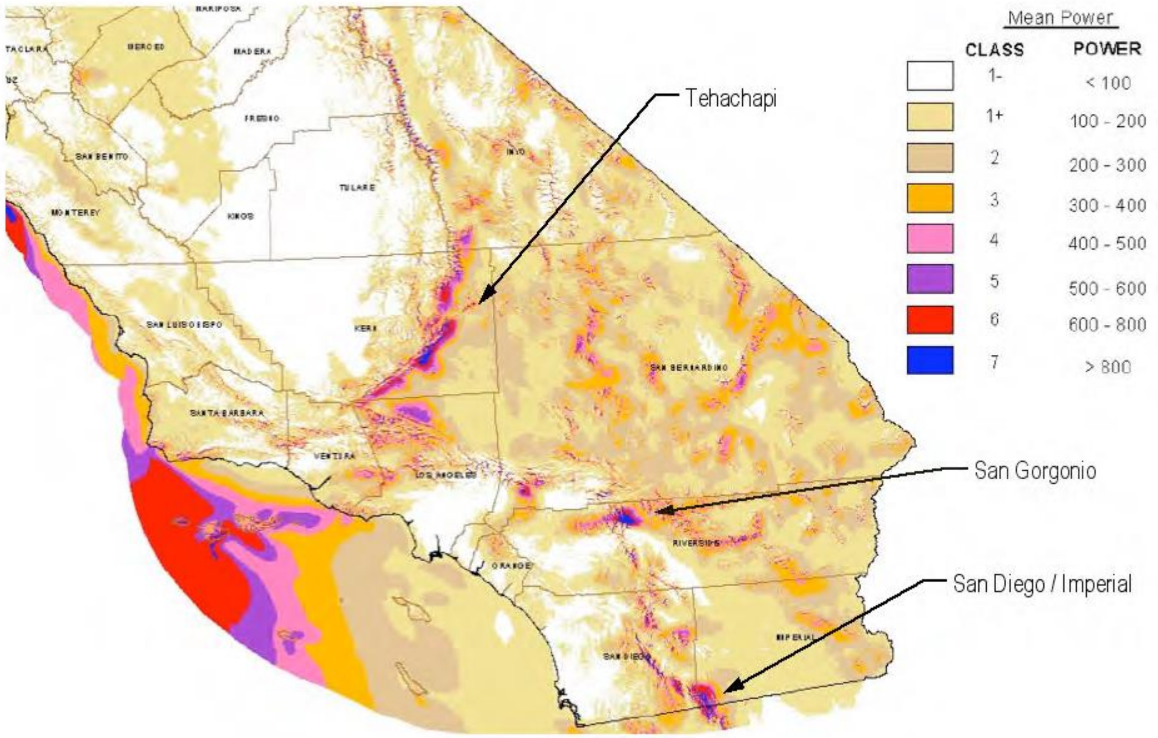
Figure 26 and **Figure 27** show the locations of California's existing wind resources, as well as the generally recognized names of the wind resource areas currently under development. In Northern California, the Solano, Altamont, and Pacheco resource areas are the most productive, and all have wind farms located within those regions. In Southern California, the Tehachapi, San Gorgonino, and San Diego/Imperial resource areas are also home to existing wind installations.

Figure 26: Wind Resource Map of Northern California With Project Developments



Source: Energy Commission. *Wind Power Generation Trends at Multiple California Sites*. *Public Interest Energy Research (PIER) Interim Project Report*, CEC-500-2005-185.

Figure 27: Wind Resource Map of Southern California With Project Developments



Source: Energy Commission. *Wind Power Generation Trends at Multiple California Sites*. *PIER Interim Project Report*, CEC-500-2005-185.

Trends and Analysis

Wind power plant installations consist of multiple wind turbines connected to a single electrical meter. They are modular with the capability to add new turbines within each development, thus increasing overall plant size. Often multiple wind power plants are clustered to create a wind farm. Wind farm size in California varies dramatically from less than 1 MW to 150 MW, and many of the newer installations are within the same general area as preexisting installations.

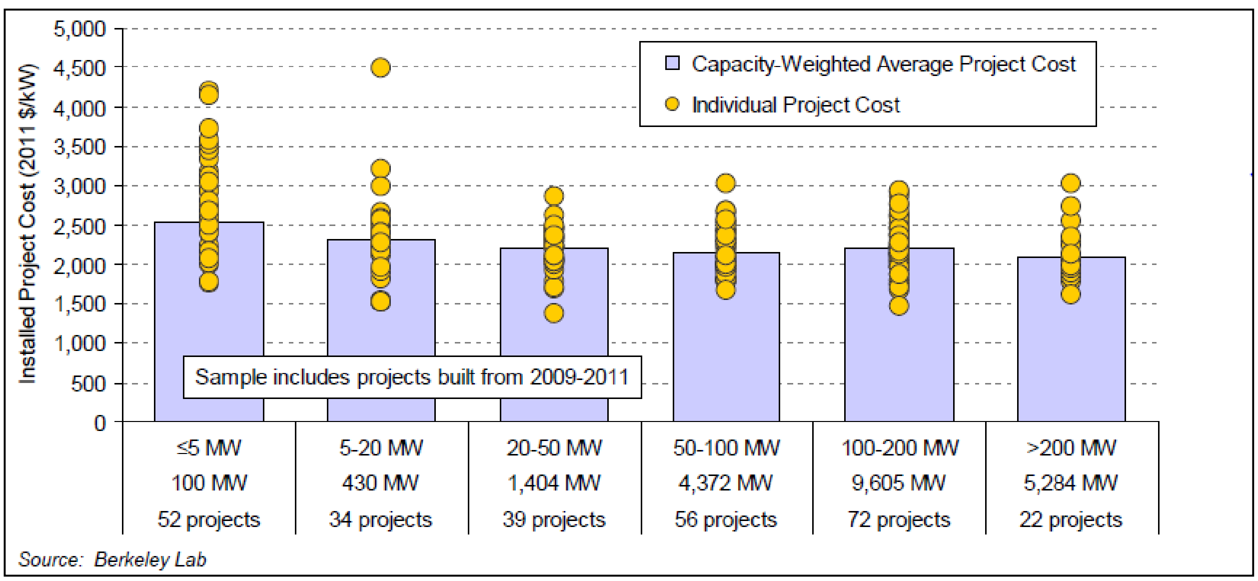
Wind technology costs have shown volatility in recent history, with project costs increasing between 2004 and 2010 before beginning a decline. Factors such as the move toward increased rotor diameter and the declining availability of high-quality wind resources have played a role in this trend. The installation of new wind farms in California is expected to continue for the foreseeable future based on continual active participation by wind developers in California renewable markets such as the Renewable Auction Mechanism[39] (Renewable Auction Mechanism, 2013).

Each of these trends primarily affects turbine prices, which are typically 75 percent of overall project installation costs (O'Connell, et al., 2007). General project cost drivers are:

- Turbine cost.
- Reliability.
- Permitting and site selection.
- Land acquisition.
- Transmission costs.

Some stakeholders consider economies of scale to be a cost driver for lowering costs. Since wind power plants are a modular technology, very few economies of scale have been seen from larger installations, as shown in **Figure 28**. However, this assessment does not include the cost of the interconnection equipment (transmission from the power plant to the existing transmission). Obviously, the cost per kW can be reduced by larger installations sharing the cost of expensive interconnection.

Figure 28: Installed Wind Project Costs as a Function of Project Size: 2009 – 2011 Projects

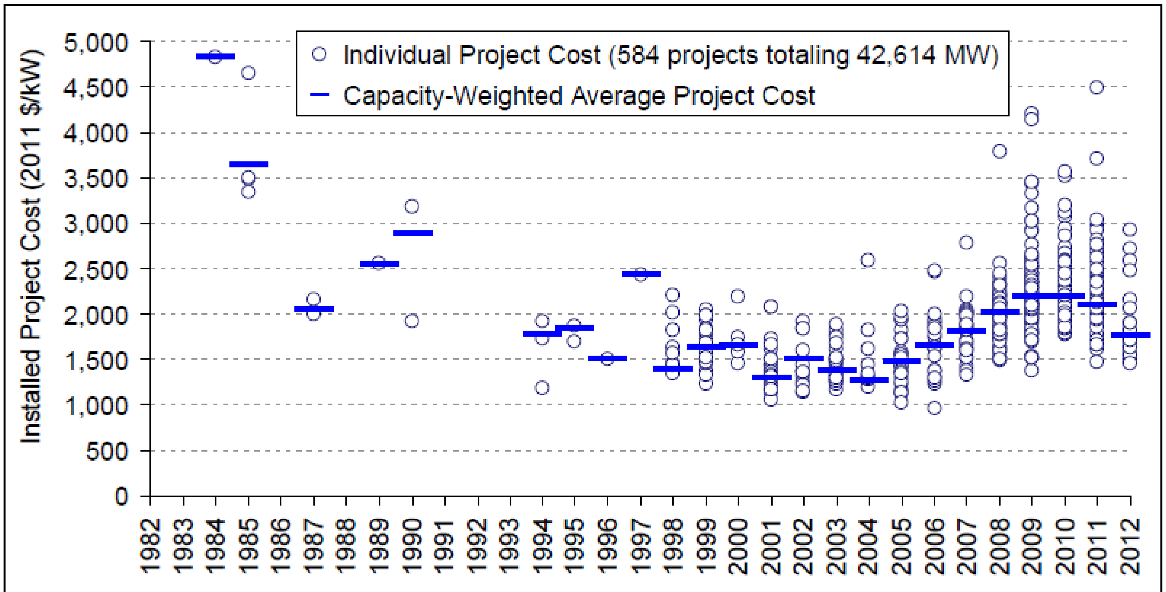


Source: Wiser and Bollinger, *2011 Wind Technologies Market Report*, EERE, 2012.

39 This is a simplified market-based procurement mechanism for renewable distributed generation projects greater than 3 MW and up to 20 MW

As shown in **Figure 29**, the cost of wind power installations across the United States showed a steady decline from the early 1980s until 2002 (Wiser and Bollinger, 2012). The trend nationally in turbine costs is from a Lawrence Berkeley National Laboratory (LBNL) study of actual installations over time (Wiser et al., 2012). Costs then rose, peaking in 2009 for many of the same reasons that power plant construction costs for other technologies peaked, such as increased labor, materials, and energy costs. The cost trend has reversed for now. The consolidation of wind manufacturers has created some instability and uncertainty in the wind turbine marketplace. No strong trend indicators are foreseen by industry observers.

Figure 29: Installed Wind Project Costs Over Time to 2012



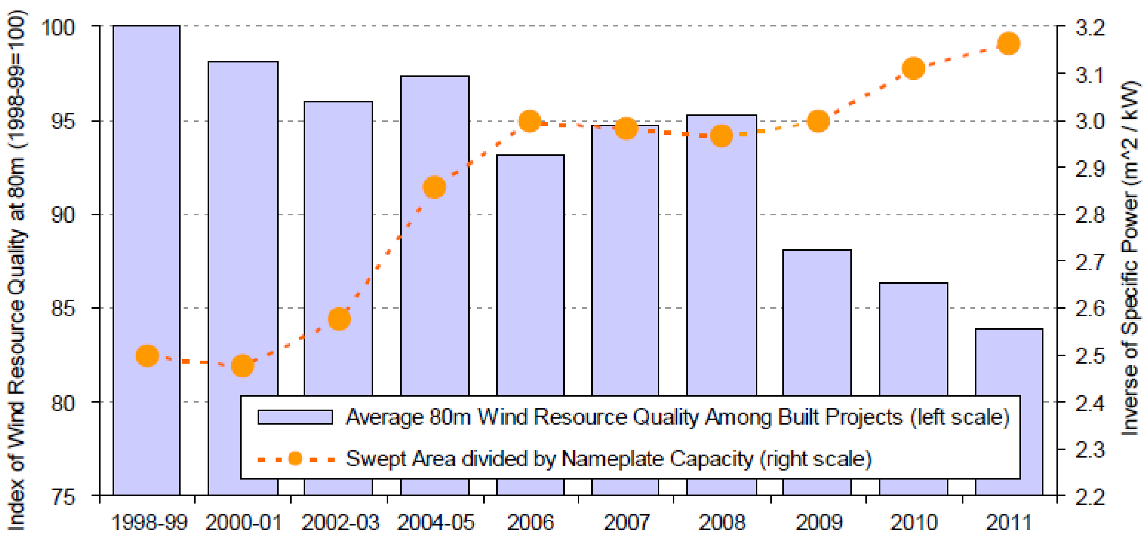
Note: 2012 data represent preliminary cost estimates for a sample of 20 projects totaling 2.6 GW that have either already been or will be built in 2012, and for which substantive cost estimates were available.
Source: Berkeley Lab (some data points suppressed to protect confidentiality)

Source: Wiser and Bollinger, *2011 Wind Technologies Market Report*, EERE, 2012.

Wind is considered a variable resource, meaning its output is determined by the daily patterns of weather rather than by a central dispatcher. The economic viability of a wind project is often determined by the average amount of energy it can produce relative to the total theoretical capacity (sometimes called *nameplate capacity*). This ratio of actual output to theoretical output is the CF. The CFs have stalled after steady improvement for many years. Increased hub heights and increased care in selecting turbine location for higher wind sites can increase CF but can also contribute to increased installed costs. Hub heights have increased only a small amount since 2006.

Figure 30 shows a decline in the average *resource quality*[40] over the last decade, and turbine designers have responded with turbines that capture more of the wind energy through a longer blade length (also known as *swept area*) and, therefore, more exposure to the force of the wind.

Figure 30: Wind Resource Quality Compared to Wind Turbine Design Changes

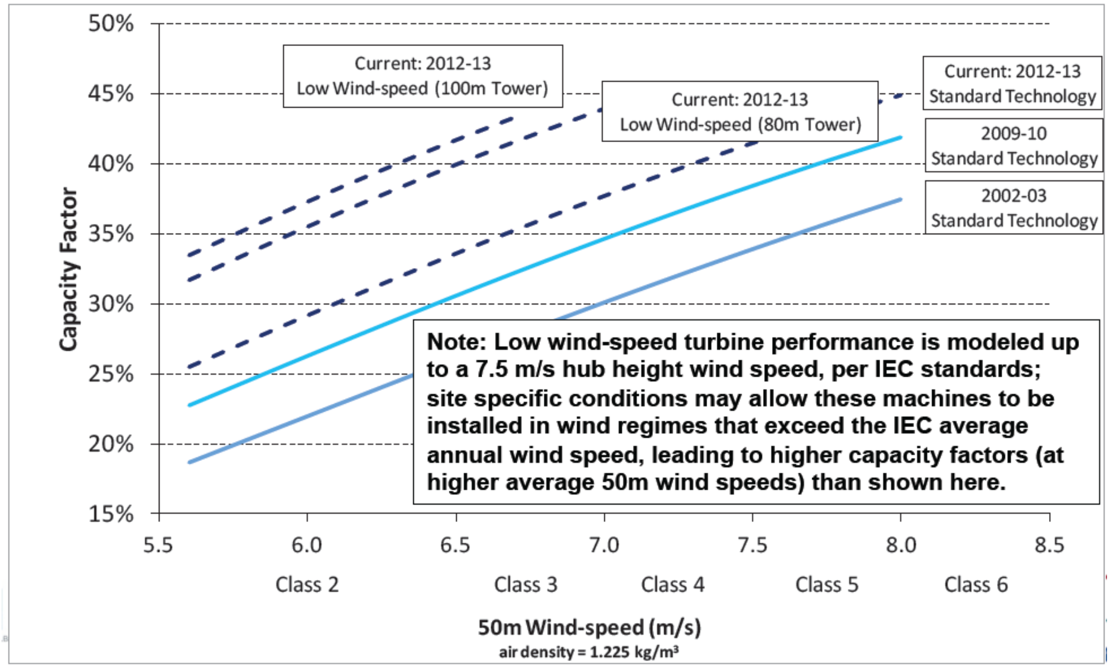


Source: Wiser and Bollinger, *2011 Wind Technologies Market Report*, EERE, 2012.

In response to the declining quality of available wind resource sites, manufacturers are offering taller turbines designed to increase overall output at lower speeds. **Figure 31** shows how the expected CF has increased with these changes in design.

40 *Resource quality* is an index number intended to capture the relative changes in power density of wind resources under development.

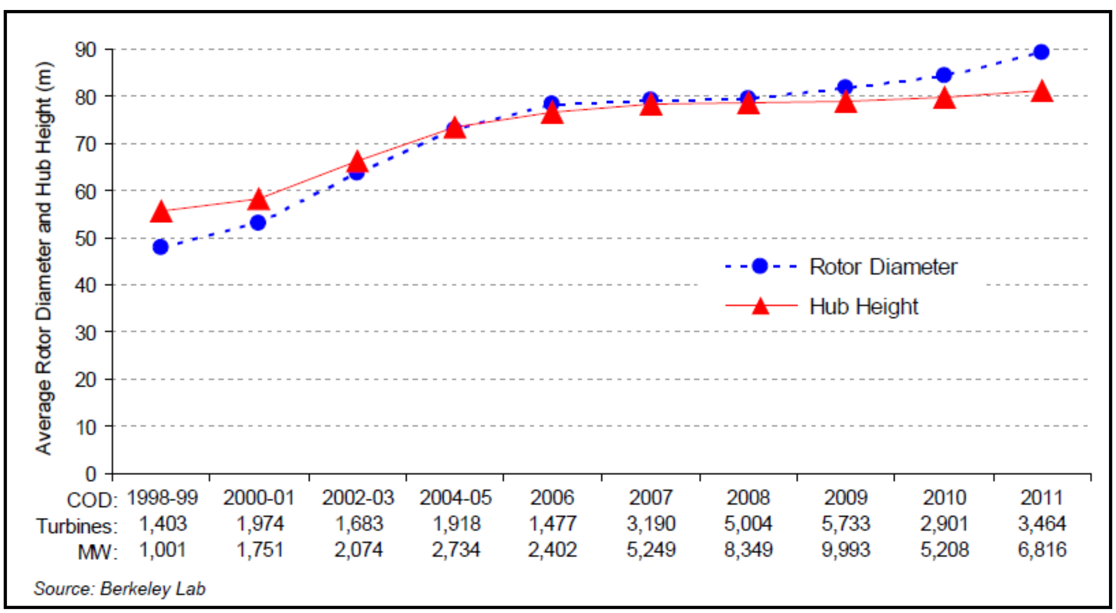
Figure 31: Changes in Capacity Factor With Turbine Redesign



Source: Wiser et al., *Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects*, LBNL, February 2012.

Wind turbine size (ratings in MW), which drives rotor diameter and hub height, has increased over time. The increased equipment costs will be at least partially offset by increased CF. **Figure 32** shows the historical trends in hub height and rotor diameter.

Figure 32: Trends in Hub Height and Rotor Diameter

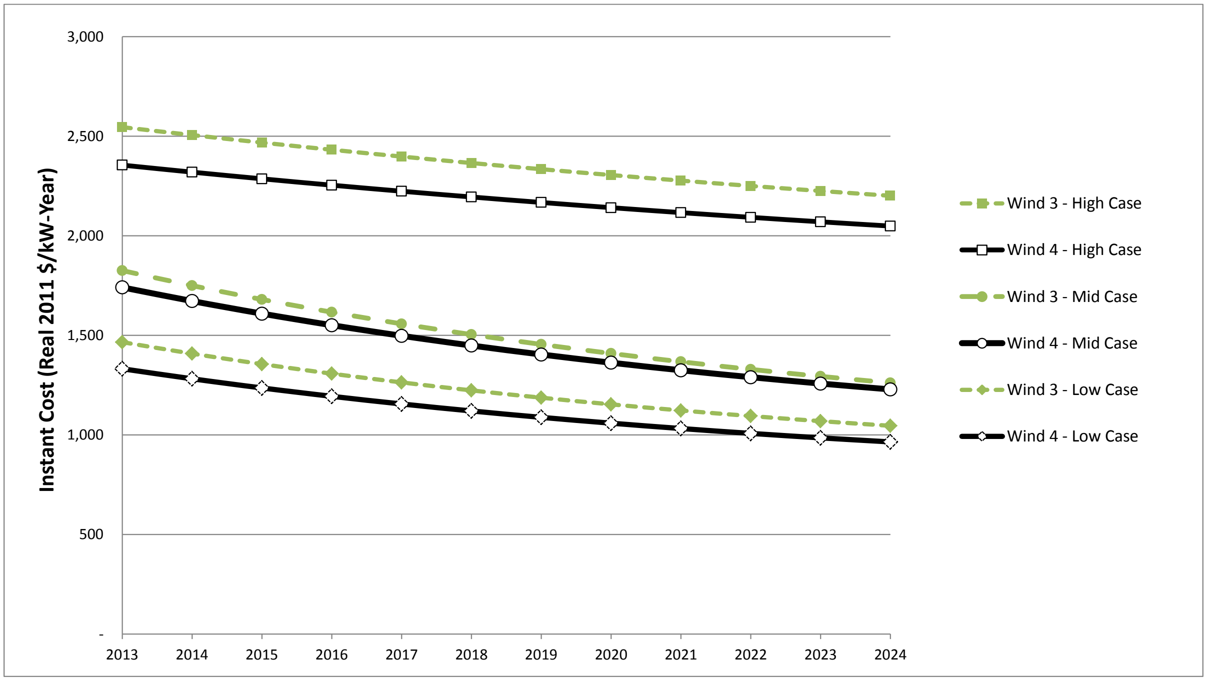


Source: Wiser and Bollinger, *2011 Wind Technologies Market Report*, EERE, 2012.

Instant Cost Trends

Figure 33 shows projected Wind Class 3 and Class 4 instant costs. Mid case costs are expected to decline in real dollars only very slightly, if at all. Other factors, such as improvements in technology and widespread adoption of best practices or high competition for skilled labor, may result in trends that vary widely from the mid case. This instability is captured in the wide range between the low- and high-cost scenarios.

Figure 33: Projected Wind Instant Costs



Source: Energy Commission.

Summary of Assumptions

A summary of assumptions for Class 4 projects can be found in **Table 35**. Unless otherwise indicated, this and subsequent assumptions in this section are based on information from several studies (Lazard, 2011; Black & Veatch, 2012; Wiser and Bollinger, 2012; Wiser, 2012).

A summary of Class 3 assumptions can be found in **Table 36**. The assumed instant costs are from the same source as for the Class 4 projects. CFs are somewhat higher than the current industry average for operational plants in commercial service, as expected based on the technology, location, and configuration trends discussed above.

Notably, a recent study from LBNL reports significant losses from station service load, although no details are offered. This effectively reduces the output capability of the wind farm and increases price. Capacity can degrade up to 0.8 percent per year, with an average value of 0.3 percent (Milborrow, 2013; Bach, 2012).

O&M costs are shown for 2011 are in nominal dollars; they are identical for both Class 3 and 4 projects. The O&M values escalate 0.5 percent per year in real dollars, driven largely by personnel costs. Total O&M cost is the combination of fixed and variable O&M and is reported to standardize the values as they are reported across technologies.

Table 35: Wind—Class 4 Project Costs

Plant Data	Mid Case	High Case	Low Case
Gross Capacity (MW)	100	100	100
Station Service	2.00%	3.00%	1.00%
Transformer Losses	0.50%	0.50%	0.50%
Capacity Factor	25.00%	21.00%	28.00%
Capacity Degradation (%/Year)	0.30%	0.80%	0.00%
Forced Outage Rate	1.00%	1.00%	1.00%
Scheduled Outage Factor	0.00%	0.00%	0.00%
2011 Instant Cost (Nominal $/kW)			
Without Ancillary Costs	$1,600	$1,800	$1,350
Interconnection Costs	$87	$216	$52
Land Costs	$200	$400	$40
Licensing Costs	$10	$15	$5
Instant Costs With Ancillary Costs	**$1,897**	**$2,431**	**$1,447**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$0.00	$0.00	$0.00
2011 Variable O&M Cost (Nominal $/MWh)	$9.00	$18.00	$5.00
2011 Total O&M Cost (Nominal $/MWh)	$9.00	$18.00	$5.00
2011 Total O&M Cost (Nominal$/kW-yr.)	$19.71	$33.11	$12.26
Insurance	0.60%	0.60%	0.60%

Source: Energy Commission.

Table 36: Wind—Class 3 Project Costs

Plant Data	Mid Case	High Case	Low Case
Gross Capacity (MW)	100	100	100
Station Service	2.00%	3.00%	1.00%
Transformer Losses	0.50%	0.50%	0.50%
Capacity Factor	26.00%	22.00%	30.00%
Capacity Degradation (%/Year)	0.55%	0.80%	0.00%
Forced Outage Rate	1.00%	1.00%	1.00%
Scheduled Outage Factor	0.00%	0.00%	0.00%
2011 Instant Cost (Nominal $/kW)			
Without Ancillary Costs	$1,700	$2,000	$1,500
Interconnection Costs	$87	$216	$52
Land Costs	$200	$400	$40
Licensing Costs	$10	$15	$5
Instant Costs With Ancillary Costs	**$1,997**	**$2,631**	**$1,597**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$0.00	$0.00	$0.00
2011 Variable O&M Cost (Nominal $/MWh)	$9.00	$18.00	$5.00
2011 Total O&M Cost (Nominal $/MWh)	$9.00	$18.00	$5.00
2011 Total O&M Cost (Nominal $/kW-yr.)	$20.50	$34.69	$13.14
Insurance	0.60%	0.60%	0.60%

Source: Energy Commission.

Summary of 2013 Wind Costs

Table 37 summarizes the 2013 instant and installed costs for the wind technologies. Installed costs reflect the need for most projects to seek financing and repay that financing arrangement over time, adding to the total cost of the project. Since the borrowing costs vary depending on the credit risk (as discussed in Chapter 2), the installed cost for the same technology will vary depending on the ownership structure. The values shown are calculated within the COG Model. **Table 38** summarizes the corresponding O&M costs.

Table 37: Summary of 2013 Instant and Installed Costs

Capital Costs	Instant Costs ($/kW)	Installed Costs ($/kW)		
Year = 2013 (Nominal Dollars)		Merchant	IOU	POU
Mid Case				
Wind - Class 3 100 MW	$1,911	$2,074	$2,085	$2,044
Wind - Class 4 100 MW	$1,822	$1,978	$1,988	$1,950
High Case				
Wind - Class 3 100 MW	$2,664	$3,099	$3,129	$3,050
Wind - Class 4 100 MW	$2,465	$2,867	$2,895	$2,822
Low Case				
Wind - Class 3 100 MW	$1,534	$1,585	$1,596	$1,573
Wind - Class 4 100 MW	$1,394	$1,441	$1,451	$1,429

Source: Energy Commission.

Table 38: Summary of 2013 Operation and Maintenance Costs

O&M Costs	Fixed O&M ($/kW-Yr.)	Variable O&M ($/MWh)	Total O&M	
Year = 2013 (Nominal Dollars)			($/kW-Yr.)	($/MWh)
Mid Case				
Wind - Class 3 100 MW	$0.00	$9.52	$21.67	$9.52
Wind - Class 4 100 MW	$0.00	$9.52	$20.84	$9.52
High Case				
Wind - Class 3 100 MW	$0.00	$19.03	$36.68	$19.03
Wind - Class 4 100 MW	$0.00	$19.03	$35.01	$19.03
Low Case				
Wind - Class 3 100 MW	$0.00	$5.29	$13.89	$5.29
Wind - Class 4 100 MW	$0.00	$5.29	$12.97	$5.29

Source: Energy Commission.

CHAPTER 7: Geothermal Technology

Overview

This study addresses two technology types of geothermal power plants associated with liquid-dominated geothermal resources, which are described more fully later on in the chapter:

- Binary Power Plants—These plants use hot liquid (called *brine*) drawn from deep beneath the earth's surface to cause another fluid to boil. The vapor created is then used to drive power turbines.
- Flash Power Plants—These plants use the hot brine drawn from the well and convert the liquid directly to steam by reducing the pressure on the liquid (called *flashing*).

Technology Description

Geothermal energy is derived from heat beneath the earth's surface that flows to the surface through a variety of pathways from hot water, steam reservoirs, or heated rock formations. Heat is carried continuously upward to the earth's surface as steam or hot water flows through permeable rock. About 94 percent of all known United States geothermal resources are located in California.[41]

Most geothermal resources fall into one of the following categories: vapor-dominated, liquid-dominated, geo-pressure, hot dry rock, and magma. Of these resources, only vapor- and liquid-dominated resources have been developed commercially for utility-scale power generation.

Vapor-dominated technology power plants, in which only steam is extracted from the geothermal well instead of brine, are not included in this cost of generation study since they are applicable to only one resource in the western United States, which are the Geysers located in Northern California.

Liquid-dominated resources are characterized by reservoir temperatures ranging from 25 degrees Celsius (°C) (77 degrees Fahrenheit [°F]) to more than 315°C (599°F). In these geothermal systems, water migrates into a well from the reservoir by a path of least resistance. In California, liquid-dominated resources are quite abundant and far more

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41 *Geothermal resources* refer to the use of thermal energy stored below the surface of the earth for converting the energy into electricity.

widespread than vapor-dominated resources. They make up more than 90 percent of known geothermal resources in the state.

Different technologies are used to generate power from geothermal resources, depending on the temperature of the resource. High-temperature geothermal resources (reservoirs with temperatures greater than 176°C [349°F]) generally use flashed steam systems. At resource temperatures lower than 176°C [349°F]), these technologies become inefficient and economically unattractive, making the binary cycle system more attractive. A binary cycle plant can use moderate temperature resources (reservoirs with temperatures between 104°C [219°F] and 176°C [349°F]) 40 percent to 60 percent more efficiently than a flashed steam facility.

Trends and Analysis

California's relative abundance of geothermal resources in comparison to the rest of the United States does not mean that geothermal power production would be viable or cost-effective everywhere in the state. Developers must consider multiple factors of cost and viability when deciding where to locate new geothermal plants. In turn, these considerations drive the estimates of future costs of new geothermal power plants in California. Considerations for developing geothermal power plants in liquid-dominated resources include (Kagel, 2006):

- Exploration Costs—Exploring and mapping the potential geothermal resource are a critical and sometimes costly. They effectively define the characteristics of the geothermal resource.
- Confirmation Costs—These are costs associated with confirming the energy potential of a resource by drilling production wells and testing the flow rates until about 25 percent of the resource capacity needed by the project is confirmed.
- Site/Development Costs—Covering all remaining activities that bring a power plant on line, including:
    - Drilling—The success rate for drilling production wells during site development average 70 percent to 80 percent (Hance, 2005). The size of the well and the depth to the geothermal reservoir are the most important factors in determining the drilling cost.
    - Project leasing and permitting—Like all power projects, geothermal plants must comply with a series of legislated requirements related to environmental concerns and construction criteria.
    - Piping network—The network of pipes are needed to connect the power plant with production and injection wells. Production wells bring the geothermal fluid (or brine) to the surface to be used for power generation, while injection wells return the used fluid back to the geothermal system to be used again.

- Power Plant Design and Construction—In designing a power plant, developers must balance size and technology of plant materials with efficiency and cost-effectiveness. The power plant design and construction depend on the type of plant (binary or flash), as well as the type of cooling cycle used (water or air cooling).
- Transmission—Includes the costs of constructing new lines, upgrades to existing lines, or new transformers and substations.

Another important factor contributing to overall costs is O&M costs, which consist of all costs incurred during the operational phase of the power plant (Hance, 2005). Operation costs consist of labor; spending for consumable goods, taxes, royalties; and other miscellaneous charges. Maintenance costs consist of keeping equipment in good working status. In addition, maintaining the steam field involves considerable expense, including servicing the production and injection wells (pipelines, roads, and so forth) and make-up well drilling.[42]

Development factors are not constant for every geothermal site. Each of the above factors can vary significantly based on specific site characteristics. Other key variable factors that drive costs for geothermal plants are project delays, temperature of the resource, and plant size.

The temperature of the resource is an essential parameter influencing the cost of the power plant equipment. Each power plant is designed to optimize the use of the heat supplied by the geothermal fluid. The size and, thus, cost of various components (for example, heat exchangers) are determined by the temperature of the resource. As the temperature of the resource increases, the efficiency of the power system increases, and the specific cost of equipment decreases as more energy is produced with similar equipment. Since binary systems use lower resource operating temperatures than flash steam systems, binary costs can be expected to be higher. **Figure 34** provides estimates for cost variance due to resource temperature. As the figure shows, binary systems range in cost from $2,000/kW to slightly more than $4,000/kW, while flash steam systems range from $1,000/kW to just above $3,000/kW (Hance, 2005).

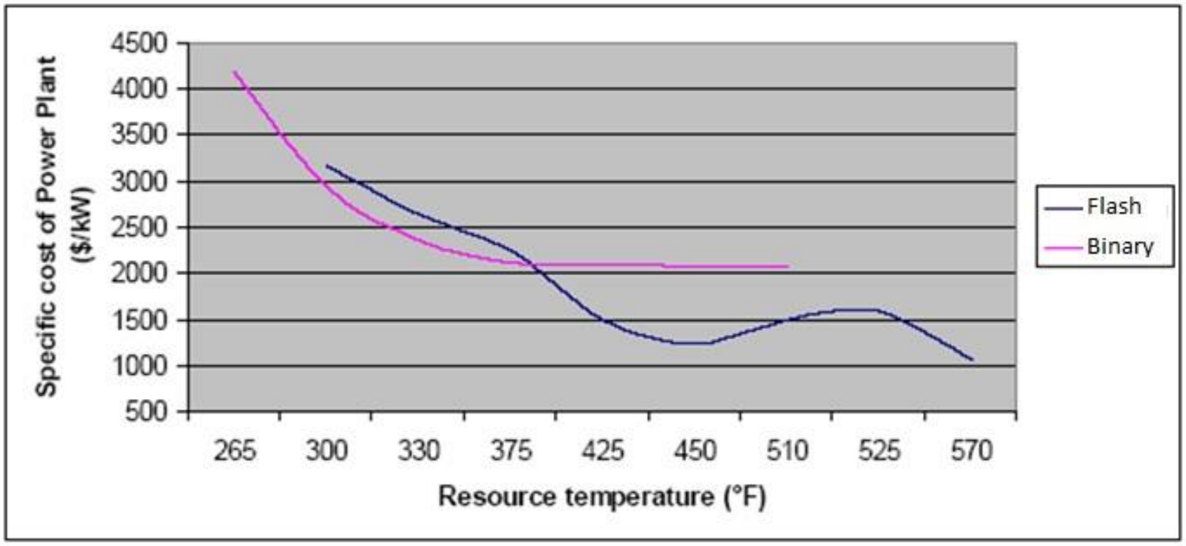
Geothermal—Binary

Binary-cycle geothermal power plants pass moderately hot geothermal brine by a secondary fluid with a much lower boiling point than water as shown in **Figure 35**. This process causes the secondary fluid to boil, creating vapor, which then drives the turbines. California binary plants range in size from 0.7 to 47.8 MW, with most between 20 MW and 30 MW. Each of

42 *Make-up drilling* aims to compensate for the natural productivity decline of the project start-up wells by drilling additional production wells.

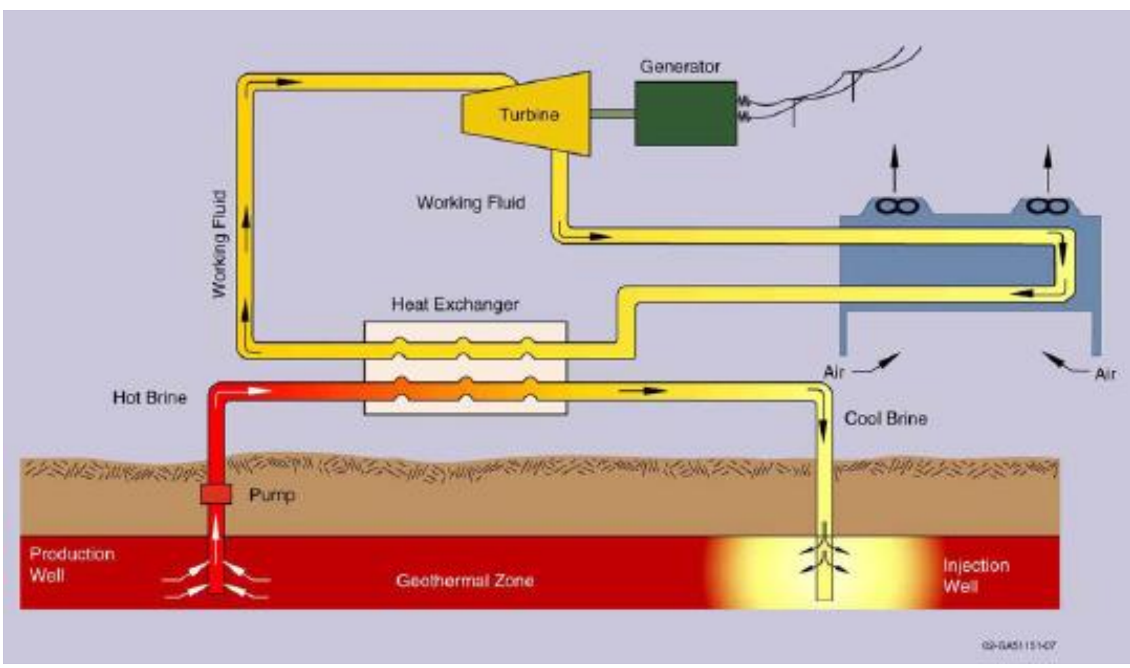
these plants can have several generators. The average generator size in use in California is about 4 MW.

Figure 34: Specific Cost of Geothermal Power Plant Equipment vs. Resource Temperature



Source: Hance, *Factors Affecting Costs of Geothermal Power Development*.

Figure 35: Binary Geothermal Power Plant



Source: Idaho National Laboratory.

Binary geothermal is a mature technology with plants operating in California since the mid-1980s. Several specific sites have been identified in California suitable for binary plant development. Current California binary geothermal installations total 140 MW (Geothermal Power, 2012). An additional 240 MW of potential development could use binary technology (Sison-Lebrilla and Tiangco, 2005). Should these sites be developed, the less expensive sites (greatest return on investment) would be first, with the more expensive sites to follow. As a result, any learning curve in binary system development would most likely be a cost avoidance rather than a cost saving, making cost reduction trends unlikely.

Summary of Assumptions

Costs and plant characteristics for binary geothermal plants shown in **Table 39** were derived from a review of publicly available reports and studies (U.S. EIA, 2010; Hahn et al., 2010; Lazard, 2011; Black & Veatch, 2012; Tidball et. al., 2010; Gifford and Grace, 2011; Geothermal Technologies, 2012; ANL, 2011). Only studies that distinguished between binary and flash technology were used for capital cost components.

Instant costs ranged from a low case (EIA, 2010; Hahn et al., 2010) of $4,213/kW to a high case (Geothermal Technologies, 2012) of $6,550/kW, with a midpoint (Tidball et al., 2010) estimate of $5,103/kW. Costs are for 2011 and are in nominal dollars. These capital costs can vary widely due to several factors, the most important of which are well drilling costs and success rate. Well costs can be more than half of the capital costs.

The fixed O&M costs reflect the total O&M costs because the power plants are operated as base load so that variable O&M is assumed to be zero.[43]

Fixed O&M costs range from a low case (Tidball et al., 2010) of $84.93 $/kW-yr. to a high case (Geothermal Technologies, 2012) of $146.40 $/kW, with a midpoint (EIA, 2010; Hahn et al., 2010) estimate of $84.93 per kW. Costs are for 2011 and are given in nominal dollars. The O&M cost is assumed to have a real escalation rate of 0.5 percent per year over the study period.

CFs were found to range from 77 to 95 percent, with 85 percent being the mid case value (Tidball, et al., 2010). These CFs are consistent with operational plants in commercial service. Capacity can degrade up to 2 percent per year, and thermal efficiency (measured as heat rate) can decline up to 5 percent a year (Gifford and Grace, 2011).

Most estimates of emissions show no GHG emissions for binary geothermal plants, but one study estimated emissions at 120 pounds per MWh. Staff used the range of zero to 120 pounds per MWh to establish a range of GHG emissions estimates for the three cases.

Geothermal resources are typically built on public lands and are often required to make royalty payments. Royalty payments to the U.S. Bureau of Land Management (BLM)

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43 The mix of fixed and variable O&M costs and differing capacity factors make direct comparisons of the cost ranges among studies difficult without digesting each to a single parameter.

typically run 3 percent of power sale revenues but can vary between 0 and 5 percent (Gifford and Grace, 2011).

Table 39: Binary Geothermal Physical and Cost Parameters

Plant Data	Mid Case	High Case	Low Case
Gross Capacity (MW)	30	30	30
Station Service	11.50%	14.50%	8.50%
Transformer Losses	0.50%	0.50%	0.50%
Capacity Factor	85.00%	77.09%	95.00%
Capacity Degradation (%/Year)	0.50%	2.00%	0.00%
Heat Rate Degradation (%/Year)	3.00%	5.00%	0.00%
Heat Rate (Btu/kWh)	34,377	34,633	34,120
Forced Outage Rate	2.50%	2.80%	2.20%
Scheduled Outage Factor	4.00%	12.00%	2.00%
2011 Instant Cost (Nominal $/kW)			
Without Ancillary Costs	$4,728	$5,594	$4,015
Interconnection Costs	$265	$670	$158
Land Costs	$90	$186	$30
Licensing Costs	$20	$100	$10
Instant Costs With Ancillary Costs	**$5,103**	**$6,550**	**$4,213**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$84.93	$146.40	$84.93
2011 Variable O&M Cost (Nominal $/MWh)	$0.00	$0.00	$0.00
2011 Total O&M Cost (Nominal $/MWh)	$11.41	$21.68	$10.21
2011 Total O&M Cost (Nominal$/kW-yr.)	$84.93	$146.40	$84.93
Insurance (%/Year)	0.60%	0.60%	0.60%
Royalties	3.00%	5.00%	0.00%
Emission Factors			
NOX (lbs/MWh)	N/A	N/A	N/A
VOC/ROG (Lbs/MWh)	N/A	N/A	N/A
CO (Lbs/MWh)	N/A	N/A	N/A
CO2 (lbs/MWh)	-	120	-
SOX (lbs/MWh)	N/A	N/A	N/A
PM10 (lbs/MWh)	N/A	N/A	N/A

Source: Energy Commission.

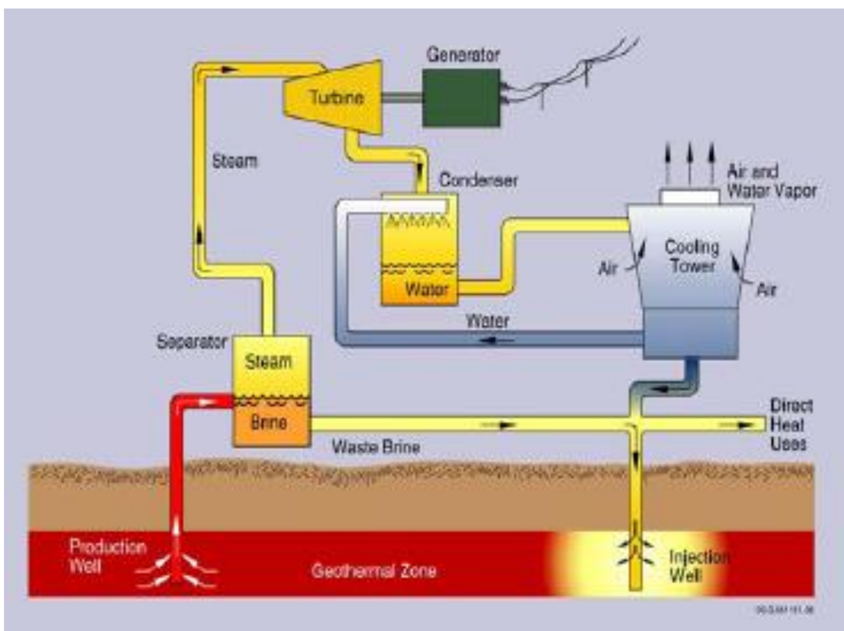
Geothermal—Flash

Flash steam plants pull deep, high-pressure brine into lower-pressure tanks and use the resulting flashed steam to drive turbines. This is the most common type of geothermal plant in operation today. In a flash steam system, as shown in **Figure 36**, geothermal brine typically between 104°C and 176°C is brought to the surface and piped to a separation tank where the pressure is reduced, causing the fluid to flash into steam. In a single-flash system, hot fluid is drawn to the surface. A fraction of the hot water "flashes" to steam when exposed to the lower pressure within the separator.

The steam is then passed through a turbine to generate power. Typically the liquid fraction is then injected back into the reservoir. During this process, as much as 60 percent of the usable heat extracted from the reservoir may be lost. To improve efficiency, a variation on the flash design known as *dual-flash systems* are used in which the geothermal fluid is flashed twice, increasing the amount of steam to the turbine. Dual-flash technology imposes a second-stage separator onto a single-flash system. This second-stage steam has a lower pressure and is put into either a later stage of a high-pressure turbine or a second lower-pressure turbine. The steam exiting the turbine is condensed. Dual-flash technology is in the range of 10 percent to 20 percent more efficient than single-flash technology.

Most California plants use one generator, but some use two or three generators. Total plant capacities range from 10 MW to 52 MW, with most at about 30 MW. Current California flash geothermal installations total 700 MW (Geothermal Power, 2012). The additional potential development of flash technology is 2,220 MW (Sison-Lebrilla and Tiangco, 2005).

Figure 36: Geothermal Flash Power Plant



Source: Idaho National Laboratory.

In addition to the cost factors listed in the previous section of the report addressing geothermal binary plants, for some flash plants a corrosive geothermal fluid may require the use of resistive pipes and cement. Adding a titanium liner to protect the casing may significantly increase the cost of the well. This kind of requirement is rare in the United States, found only in the Salton Sea resource in Southern California (Hance, 2005). However, this may be worth additional research since the most recent geothermal flash plant built in California was a 49.9 MW plant built by EnergySource that came on-line in 2012, the first in more than 20 years.

Summary of Assumptions

Costs and plant characteristics for flash geothermal plants are shown in **Table 40**. These were derived from review of publicly available reports and studies (EIA, 2010; Hahn, et al., 2010; Lazard, 2011; Black & Veatch, 2012; Tidball, et al., 2010; Gifford and Grace, 2011; Geothermal, 2012; ANL, 2011; Stora and Rundquist, 2010; Holm, 2012). As with the binary plants, only studies that distinguished between binary and flash were used for developing capital cost components.

Estimated instant or overnight cost (expressed in nominal 2011 $/kW) ranges from a low case (Tidball et al., 2010) of $3,637/kW to a high case (Geothermal Technologies, 2012) of $7,807/kW, with a mid case (EIA, 2010; Hahn et al., 2010) estimate of $5,765/kW. Costs are for 2011 and are in nominal dollars.[44] As with the binary plants, these capital costs can vary widely due to a number of factors, the most important of which are well drilling costs and success rates. Well costs account for more than half of the capital costs of geothermal flash plants.

O&M costs are given solely in terms of fixed O&M because the plants run as base load resources and therefore have the same O&M costs each year.[45] The costs range from a low case of $81.48 $/kW-yr. to a high case of $172.69 $/kW, with a midpoint estimate of $84.93 $/kW. Costs are for 2011 and are given in 2011 dollars. O&M costs are assumed to have a real escalation rate of 0.5 percent.

CFs were found to range from 72 percent (Tidball et al., 2010) to 95 percent (Geothermal Technologies, 2012), with 85 percent (Tidball et al., 2010) being the mid case value. These CFs are consistent with operational plants in commercial service. Capacity can degrade up to 2 percent per year, and thermal output can decline up to 5 percent a year (Gifford and Grace, 2011).

GHG emissions range from 99 pounds per MWh (Holm, et al., 2012) to 397 pounds per MWh (Geothermal, 2012), with a mid case of 264 pounds per MWh (Walters, 2013). Royalty payments to the BLM typically run 3 percent of power sale revenues but can vary between 0 and 5 percent, with an average value of 3 percent.

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44 Costs are expressed initially in 2011$ since the majority of sources use 2011 as the base year. These values are updated to 2013$ later in the chapter and prior to being used in the COG Model.

45 The mix of fixed and variable O&M costs and differing capacity factors make direct comparisons of the cost ranges among studies difficult without digesting each to a single parameter.

Table 40: Flash Geothermal Physical and Cost Parameters

Plant Data	Mid Case	High Case	Low Case
Gross Capacity (MW)	30	30	30
Station Service	17.00%	20.00%	14.00%
Transformer Losses	0.50%	0.50%	0.50%
Capacity Factor	85.00%	71.81%	95.00%
Capacity Degradation (%/Year)	0.50%	2.00%	0.00%
Heat Rate Degradation (%/Year)	3.00%	5.00%	0.00%
Heat Rate (Btu/kWh)	34,377	34,633	34,120
Forced Outage Rate	2.50%	2.80%	2.20%
Scheduled Outage Factor	4.00%	12.00%	2.00%
2011 Instant Cost (Nominal $/kW)			
Without Ancillary Costs	$5,357	$6,826	$3,401
Interconnection Costs	$265	$670	$158
Land Costs	$90	$186	$30
Licensing Costs	$53	$125	$48
Instant Costs With Ancillary Costs	**$5,765**	**$7,807**	**$3,637**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$84.93	$172.69	$81.48
2011 Variable O&M Cost (Nominal $/MWh)	$0.00	$0.00	$0.00
2011 Total O&M Cost (Nominal $/MWh)	$11.41	$27.45	$9.79
2011 Total O&M Cost (Nominal$/kW-yr.)	$84.93	$172.69	$81.48
Insurance (%/Year)	0.60%	0.60%	0.60%
Royalties	3.00%	5.00%	0.00%
Emission Factors			
NOX (Lbs/MWh)	0.191	0.191	0.191
VOC/ROG (Lbs/MWh)	0.011	0.011	0.011
CO (Lbs/MWh)	0.058	0.058	0.058
CO2 (Lbs/MWh)	264.5	397.0	98.9
SOX (Lbs/MWh)	0.026	0.026	0.026
PM10 (Lbs/MWh)	0	0	0

Source: Energy Commission.

Summary of 2013 Geothermal Cost Data

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Table 41 summarizes instant and installed costs for 2013 in nominal (2013) dollars. Instant costs include all costs plus land and permitting costs. *Installed cost* is the instant cost plus the cost of financing the plant during construction, and development fees (loan fees and insurance).

Table 41: Summary of 2013 Instant and Installed Costs

Capital Costs	Instant Costs ($/kW)	Installed Costs ($/kW)		
Year = 2013 (Nominal Dollars)		Merchant	IOU	POU
Mid Case				
Binary Geothermal 30 MW	$5,342	$6,743	$6,865	$6,160
Flash Geothermal 30 MW	$6,039	$7,382	$7,493	$6,858
High Case				
Binary Geothermal 30 MW	$6,869	$9,538	$9,733	$9,005
Flash Geothermal 30 MW	$8,188	$10,987	$11,181	$10,455
Low Case				
Binary Geothermal 30 MW	$4,410	$4,843	$4,917	$4,680
Flash Geothermal 30 MW	$3,814	$4,148	$4,204	$4,026

Source: Energy Commission.

Table 42 summarizes O&M costs for 2013 in nominal dollars. Costs are assumed to have a real escalation rate of 0.5 percent per year.

Table 42: Summary of Operating and Maintenance Costs

O&M Costs	Fixed O&M ($/kW-Yr.)	Variable O&M ($/MWh)	Total O&M	
Year = 2013 (Nominal Dollars)			($/kW-Yr.)	($/MWh)
Mid Case				
Geothermal Binary 30 MW	$89.79	$0.00	$89.79	$12.06
Geothermal Flash 30 MW	$89.79	$0.00	$89.79	$12.06
High Case				
Geothermal Binary 30 MW	$154.78	$0.00	$154.78	$22.92
Geothermal Flash 30 MW	$182.58	$0.00	$182.58	$29.02
Low Case				
Geothermal Binary 30 MW	$89.79	$0.00	$89.79	$10.79
Geothermal Flash 30 MW	$86.15	$0.00	$86.15	$10.35

Source: Energy Commission.

CHAPTER 8: Biomass Technology

Overview

Biomass is plant-based material, agricultural vegetation, or agricultural wastes used as fuel and has three primary technology pathways:

- Pyrolysis—transformation of biomass feedstock materials into fuel (often liquid "biofuel") through the application of heat in the presence of a catalyst.
- Combustion—transformation of biomass feedstock materials into useful energy through the direct burning of those feedstocks using a variety of burner/boiler technologies also used for burning materials such as coal, oil, and natural gas.
- Gasification—transformation of biomass feedstock materials into synthetic gas through the partial oxidation and decomposition of those feedstocks in a reactor vessel and oxidation.

Of these technology pathways, only direct combustion of biomass is commercially available for utility-scale plants and, thus, is the focus of this section, specifically a 50 MW fluidized bed boiler. Gasification methods are used in some small-scale applications but are not yet viable for utility-scale applications. Active research into pyrolysis for biofuel production is ongoing but is not used for electricity production.

Technology Description

Combustion technologies are widespread and include the following general approaches:

- *Stoker boiler combustion* uses similar technology for coal-fired stoker boilers to combust biomass materials, using either a traveling grate or a vibrating bed.
- *Fluidized bed combustion* uses a special form of combustion where the biomass fuel is suspended in a mix of silica and limestone through the application of air through the silica/limestone bed. This is similar to technology used in newer coal-fired boilers. Fluidized bed combustion boilers are classified as either bubbling fluidized bed (BFB) or circulating fluidized bed (CFB) units.
- Biomass cofiring uses biomass fuel burned in conjunction with coal products in current pulverized-coal boiler technology used in utility-scale electricity production.

Recent sources of data and analysis have focused on the fluidized bed technology. It is also the most likely biomass technology to be installed in California. The remainder of this chapter will focus on fluidized bed technology.

For biomass fuels, fluidized bed combustion appears to be the current technology of choice for biomass power generation applications. A traditional-style boiler burns the solid fuel in a stationary bed, similar to the way logs burn on a fire. A fluidized bed style, however, mixes the fuel and keeps it suspended in a column of hot gases that increases the quality of combustion. In addition to keeping the biomass fuel suspended in hot gases, modern fluidized bed boilers also use a nonburning combustion media to help retain heat and improve combustion. This medium is typically a mix of silica and/or alumina.

The inherent fuel versatility of fluidized bed systems provides a plant operator the ability to burn many biomass resource types, including those feedstocks with significant moisture variations.[46] The major reason for this is that the fluidized bed carrying medium provides a thermal flywheel effect that maintains constant heat output and flue gas quality even when burning fuels of varying moisture content (Overend, 2002).

Fluidized bed boilers are characterized as either BFB or CFB, depending on how the bed material is used within the boiler. In a BFB unit, the bed material stays within a fixed zone in the boiler, while in a CFB unit, the material is suspended above an air zone and is circulated through a return loop back to the combustion zone.

For both BFB and CFB units, due to the high-quality combustion and near-complete carbon burnout (99 percent – 100 percent) of biomass fuel sources, ash is carried over into the flue gas stream, necessitating the addition of postcombustion ash removal equipment such as cyclones and baghouses.[47] The postcombustion controls allow particulate removal to meet New Source Performance Standards (NSPS) for PM10.

46 Moisture variations can produce wide swings in energy output in conventional boiler technologies. Since drying biological material adds cost and reduces the range of available fuels, boiler designs that are capable of dealing with these variations are typically preferred.

47 *Cyclones* remove ash by rapidly changing the direction of the air, causing particles to fall out. A *baghouse* uses large filters to remove particles.

Trends and Analysis

When planning for and developing biomass, the following considerations affect the potential viability and costs:[48]

- Biomass fuel type and uniformity—The type and uniformity of delivered biomass fuel supply are a primary cost driver for any biomass technology. Given the variation of the delivered moisture content and heating value of biomass fuel feedstocks, along with fuel processing issues, the handling and processing costs of biomass fuels can vary greatly. As a result, the type and characteristics of the different biomass fuels can have a material effect on the capital cost of the boiler design, as well as the overall fuel handling and operations cost.
- Fuel transport and handling costs—The availability of sufficient biomass fuel resources near the plant location is a critical driver for operating cost. Most biomass fuel is transported by truck to a plant site. To maintain commercially reasonable prices, the effective economic radius from the plant location to the combined fuel supply is limited to about 100 miles. The varied nature of biomass fuel feedstocks also necessitates special handling equipment and larger numbers of dedicated staff than are needed for coal-fired combustion power plants of equivalent size. As a result, the typical maximum size of biomass plants is limited to about 50 MW in California (McCann, et al., 1994).
- Boiler island cost—Capital cost of the boiler island, the location where biomass combustion occurs, is a critical cost driver that can account for roughly 40 to 60 percent of the overall plant cost, depending on the type of biomass combusted and the need for postcombustion pollution controls. Thus, the choice of source and type of fuels to be combusted is an important capital cost driver. In addition, the escalation trends for raw materials used in manufacturing the boiler island, primarily steel cost, are factors that can influence delivered boiler island cost.
- Long-term fuel supply contracts—Most current biomass fuel supply contracts are of short-term duration and can entail varying fuel qualities. A key cost barrier to promoting biomass circulating bed combustion in California is the ability to develop and achieve performance on long-term (for example, five years duration and longer) fuel supply contracts for available fuel sources.
- Plant scale—While current CFB technology has been proven to utility-scale applications of up to 300 MW, supply availability limits potential plant scale. Steam-generator scale economies are substantial, with a 50 MW biomass plant likely to cost substantially more per kW than a 500 MW coal-fired plant of the same technology (McCann, et al., 1994).
- Emissions control costs—Costs of emission control needed to satisfy air quality and permitting requirements can increase the cost of biomass plants. Postcombustion emissions control technologies, such as selective catalytic reduction/selective

48 These considerations are not quantified here as that is beyond the scope of this study.

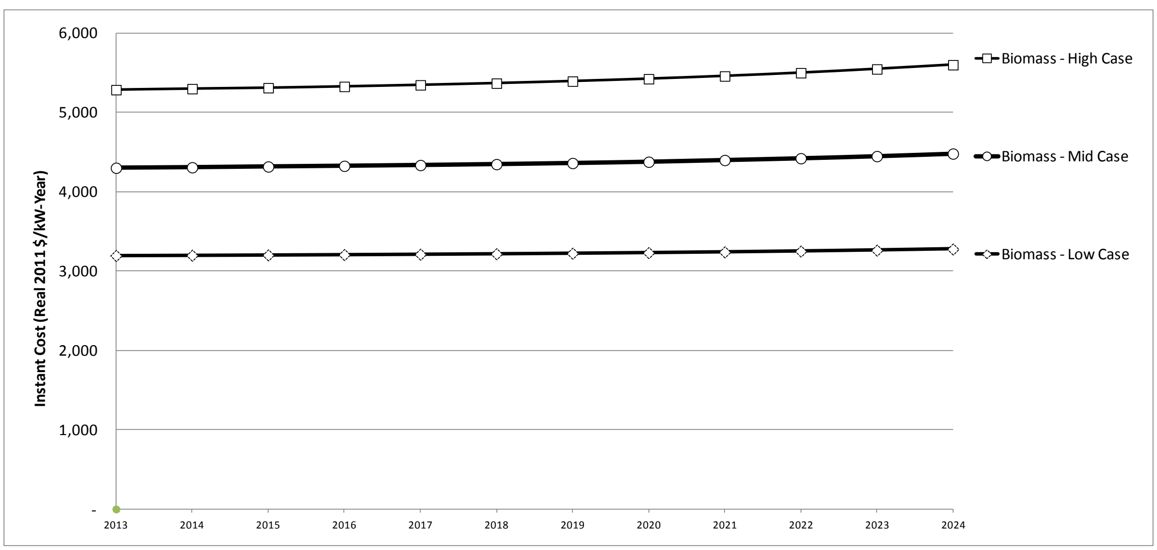
noncatalytic reduction technologies for NO_x control and additional particulate matter controls, are important cost drivers that can significantly increase the capital and operating costs of biomass plants.

- Retrofit versus greenfield new site—For many biomass fluidized bed applications, repowering is a commercially viable option that can save 20 percent to 40 percent of the capital cost of a new greenfield site where all the remainder of plant systems would need to be constructed.
- O&M capitalization—The extent to which the long-term operations and maintenance of a biomass fluidized bed facility are capitalized through a long-term maintenance contract with an original equipment manufacturer supplier is a cost driver. These long-term maintenance contracts trade risk for maintenance cost predictability and can slightly change the operating cost profile of a commercial biomass fluidized bed boiler plant.

Instant Cost Trends

The projected costs for the gas-fired technologies are shown in **Figure 37.** It is assumed that there is no real escalation for equipment, but instant cost escalates due to the real escalation of ERCs.

Figure 37: Biomass Instant Costs



Source: Energy Commission.

Summary of Assumptions

Plant data for biomass CFB boiler plants shown in **Table 43** were derived from a review of publicly available reports and studies (U.S. EIA, 2010; Hahn, et al., 2010; Tidball, et al., 2010;

Lazard, 2011; Black & Veatch, 2012; McCann, 2012). Costs are adjusted from U.S. averages to California sites based on cost indices contained in the R.W. Beck study.

Plant capacities for biomass fluidized bed boilers were established in a range of 15 MW to 70 MW, with 50 MW being used as a typical plant capacity. The capacity range is primarily set by the effective biomass fuel supply range, along with the most common sizes of biomass CFB designs today.

Instant (or overnight) cost data for biomass CFB plants ranged from a low case of $3,190/kW to a high case of $5,263/kW, with a midpoint estimate of $4,290/kW. Costs are for 2011 and are in nominal dollars; these are assumed to remain constant in real dollars. Instant costs are for equipment and construction only and do not include costs such as land and permitting costs, which would increase mid costs by about 2 percent. As discussed in the previous section, these capital costs can vary widely due to several factors, including type of fuel and fuel mix burned, size/scale of the plant, whether the site is a brownfield redevelopment or a greenfield site, and the amount of postcombustion pollution controls. Typically, the boiler island comprises 40 – 60 percent of the total instant plant cost.

O&M costs are broken into fixed and variable components. Therefore, mid, high, and low costs need to be compared on a total O&M basis. Total O&M varies from a low of $18.50/MWh to $28.87/MWh, with a mid cost value of $19.22/MWh. Costs are for 2011 and are given in 2011 dollars. The O&M cost is assumed to have a real escalation rate of 0.5 percent over the study period.

CFs were found to range from 78 percent to 85 percent, with 81 percent being the mid case value. These CFs are consistent with operational CFB boilers in commercial service.

Estimated heat rates average about 14,500 British thermal units per kilowatt hour (Btu/kWh), with a lower bound of 13,500 Btu/kWh. Heat rates can vary for biomass CFB systems due to fuel moisture content and heating value.

No significant experience curve effects or learning effects are taken into consideration in the analysis, as CFB technology is considered a mature technology. Cost drivers should not have a significant effect on the long-term levelized cost values, absent a disruptive shift in the current technology and approach to biomass CFB combustion.

Table 43: Biomass Physical and Cost Parameters

Plant Data	Mid Case	High Case	Low Case
Gross Capacity (MW)	50	50	50
Station Service	4.00%	7.00%	2.00%
Transformer Losses	0.50%	0.50%	0.50%
Capacity Factor	80.70%	78.20%	85.00%
Capacity Degradation (%/Year)	0.10%	0.20%	0.00%
Heat Rate Degradation (%/Year)	0.15%	0.20%	0.10%
Heat Rate (BTU/kWh)	14,500	14,500	13,500
Forced Outage Rate	9.00%	9.00%	0%
Scheduled Outage Factor	7.60%	7.60%	0%
2011 Instant Cost (Nominal $/kW)			
Without Ancillary Costs	$4,032	$4,658	$3,048
Interconnection Costs	$159	$402	$95
Land Costs	$38	$99	$13
Licensing Costs	$61	$104	$34
Instant Costs With Ancillary Costs	**$4,290**	**$5,263**	**$3,190**
2011 Fixed O&M Cost (Nominal $/kW-yr.)	$100.50	$95.00	$100.50
2011 Variable O&M Cost (Nominal $/MWh)	$5.00	$15.00	$5.00
2011 Total O&M Cost (Nominal $/MWh)	$19.22	$28.87	$18.50
2011 Total O&M Cost (Nominal $/kW-yr.)	$135.85	$197.75	$137.73
Insurance	0.60%	0.60%	0.60%
Emission Factors			
NO_X (lbs/MMBtu)	0.075	0.075	0.075
VOC/ROG (Lbs/MWh)	0.012	0.012	0.012
CO (Lbs/MWh)	0.105	0.105	0.105
CO_2 (lbs/MWh)	195.00	195.00	0.00
SO_X (lbs/MWh)	0.034	0.034	0.034
PM10 (lbs/MWh)	0.100	0.200	0.025

Source: Energy Commission.

Summary of 2013 Biomass Cost Data

Table 44 summarizes instant and installed costs for 2013 in nominal dollars. Instant costs include all costs, including land and permitting costs. Installed cost is the instant cost plus the cost of financing the plant during construction, and development fees (loan fees and insurance). Capital costs are assumed to remain constant in real dollars.

Table 44: Summary of 2013 Instant and Installed Costs

Capital Costs	Instant Costs ($/kW)	Installed Costs ($/kW)		
Year = 2013 (Nominal Dollars)		Merchant	IOU	POU
Mid Case				
50 MW Biomass	$4,498	$5,068	$5,103	$4,917
High Case				
50 MW Biomass	$5,528	$6,622	$6,683	$6,478
Low Case				
50 MW Biomass	$3,343	$3,489	$3,508	$3,445

Source: Energy Commission.

Table 45 summarizes O&M costs for 2013 in nominal 2013 dollars. Besides the normal inflation, O&M costs are assumed to have a real escalation rate of 0.5 percent per year.

Table 45: Summary of Operating and Maintenance Operative and Maintenance Costs

O&M Costs	Fixed O&M ($/kW-Yr.)	Variable O&M ($/MWh)	Total O&M	
Year = 2013 (Nominal Dollars)			($/kW-Yr.)	($/MWh)
Mid Case				
50 MW Biomass	$106.26	$5.29	$143.63	$20.32
High Case				
50 MW Biomass	$100.44	$15.86	$209.08	$30.52
Low Case				
50 MW Biomass	$106.26	$5.29	$145.62	$19.56

Source: Energy Commission.

CHAPTER 9: Natural Gas-Fired Technologies

Overview

Natural gas-fired generation technologies form the backbone of California's generation portfolio today, making up about one-half of the generation in the state. Between 2001 and 2012, the Energy Commission certified 47 new natural gas power plants. While California has policy preferences for zero-emissions generation resources such as solar and wind, natural gas continues to play an important bridge role in supporting the growing portfolio of renewable resources and stabilizing the generation system.

In California, the cost to build and operate natural gas-fired technologies depends heavily on the project location, the specific type of natural gas-fired technology used, and the cost of natural gas used as a fuel source. There are two basic types of natural gas technologies—combustion turbine (CT) and combined cycle (CC).

Technology Description

In California, the CT (also known as simple cycle) power plants used closely resemble the jet engine of a large commercial airliner, such that this design is sometimes referred to as an "aeroderivative." The alternative commercial design (called a "frame" design) uses a turbine and combustion arrangement that more closely resembles a steam turbine. Aeroderivative designs give faster ramping and operational flexibility to grid operators—a necessity in a grid with large amounts of intermittent resources such as solar and wind. In California, there is a growing tendency to build advanced versions of the aeroderivative CT units that provide greater fuel efficiency, reduced costs, and reduced emissions. This report summarizes three types of CT installations: a 49.5 MW CT, a 100 MW CT that consists of two of the smaller turbines located in a single site, and an advanced design 200 MW CT.

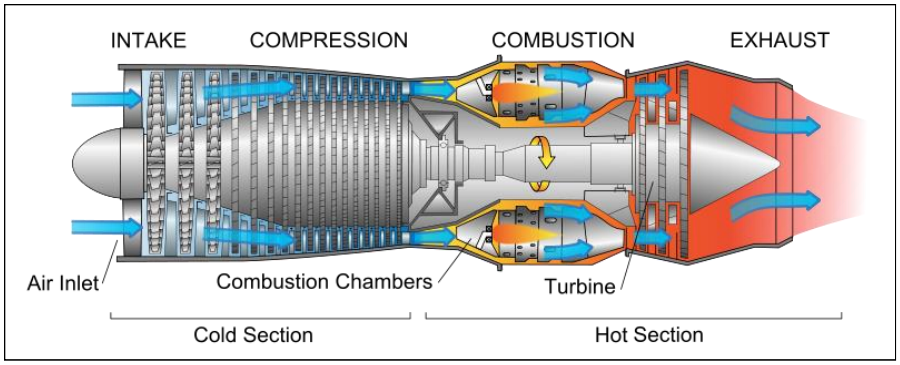
Among larger gas-fired power plants, the CC power plants use a frame design combustion turbine fueled by natural gas, and then use the hot exhaust gasses (sometimes with a small amount of additional natural gas heating) to create steam, which is used to turn a steam turbine and generate electricity. This increases the output and overall efficiency of the power plant. The tradeoff in this case is to reduce the operational flexibility of the plant and make start-up and shutdown more lengthy and costly. CC power plants are classified in this report as either "duct firing"—a reference to plants that add heat to the exhaust gas stream through additional burners in the ducting—or as conventional CCs. This report focuses on a 500 MW CC and a 550 MW CC with duct firing.

While there is one advanced design of CC power plants operating in California (specifically the Inland Empire Energy Generating Center in Menifee, Riverside County), this plant provides insufficient data from which to generate valid estimates of future construction and operation costs; therefore, this technology is not included in this report.

Conventional Combustion Turbine

This technology is most commonly referred to as a *CT* or *natural gas turbine*. The combustion turbines included herein are aeroderivatives that were developed from jet engines. They produce thrust from the exhaust gases, as illustrated **Figure 38**.

Figure 38: Aeroderivative Gas Turbine



Source: 2004 *Airplane Flying Handbook*, U.S. Federal Aviation Administration

F-Class gas turbines without additional boilers to extract energy from the exhaust gasses are often used in other areas of the country, but there is not a single F-Class turbine operating in this configuration in California. Due to the lower efficiency of the F-Class turbine alone, such use within California in the future is unlikely. The GE LM6000 gas turbine, which is the most prevalent conventional CT in California, is used for characterization in this report.

Advanced Combustion Turbine

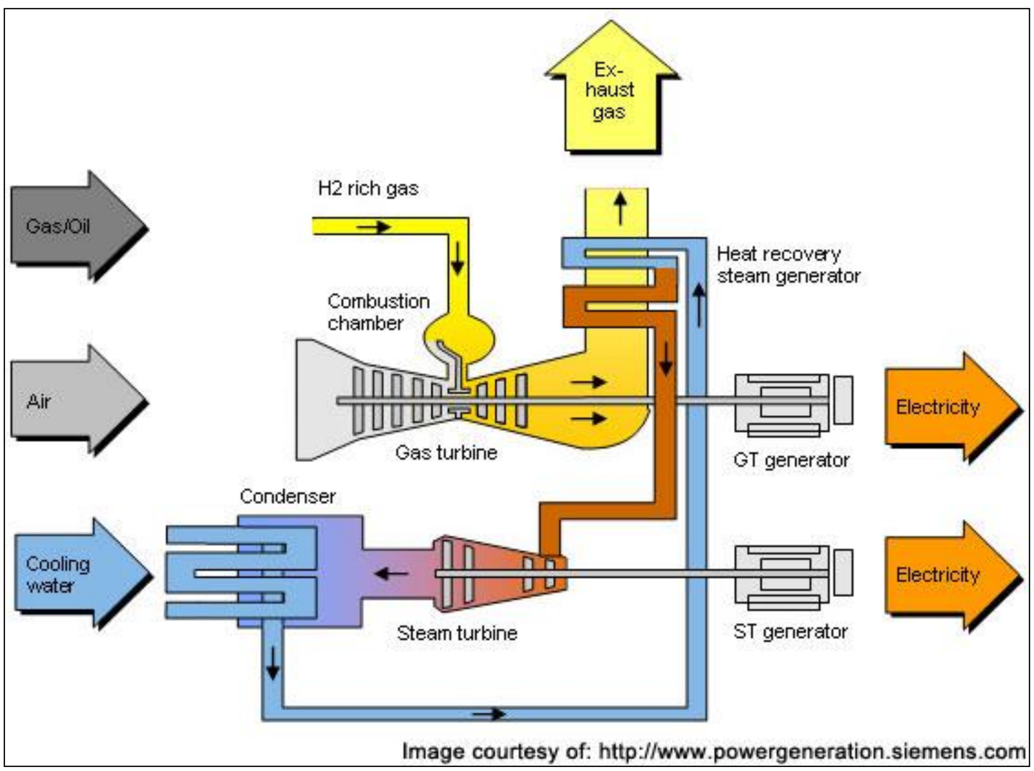
The advanced CT selected for evaluation is the GE LMS100 gas turbine. The LMS100, an aeroderivative gas turbine, provides increased power output due to the addition of an intercooling system. The intercooling system takes compressed air from the low-pressure compressor, cools it to optimal temperatures, 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. The LMS100 can achieve 44 percent thermal efficiency, which is a roughly 10 percentage point improvement over other turbines in the size range (Ecomagination, 2013).

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, or an air-cooled condenser. The previous 2007 and 2009 COG modeling efforts were for specific physical configurations. The present approach does not rely on specific physical configurations. The mid, high, and low cases are now based on an average, 90 percentile, and 10 percentile cases, respectively, of known total capital costs irrespective of the physical configuration.

Conventional Combined Cycle

This technology combines a conventional steam turbine with one or more CT units to derive a higher level of efficiency than would be possible with just the turbine alone. The exhaust heat of the CT unit is used to heat steam in the heat recovery section that leads to the steam turbine, as shown in **Figure 39**.

Figure 39: Combined-Cycle Process Flow



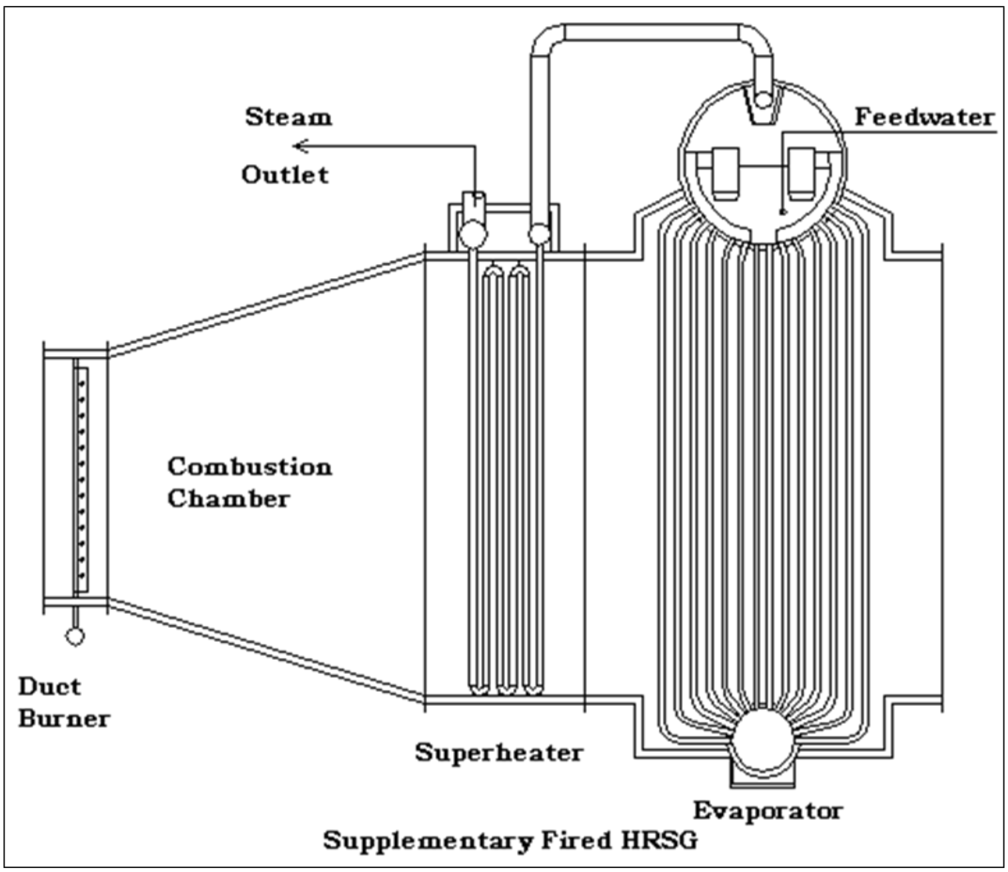
Source: See http://www.powergeneration.siemens.com.

The typical CC power plant built in California is based on the F-Frame gas CT and typically consists of two CTs and one steam turbine. However, the number of gas turbines and steam turbines varies significantly between the existing gas turbine CC power plants in California.

Conventional Combined Cycle With Duct Firing

CC 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 CC power system 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 the CF of a plant is determined based on the total duct-fired rating, will cause a corresponding decrease in the annual CF of a plant due to the limited use of the duct burners. The added efficiency of duct firing, essentially the steam cycle efficiency, is similar to the efficiency of conventional CT gas turbines but less than advanced CT gas turbines. The general layout of a CC power plant HRSG, showing the added duct burners and combustion chamber on the far left, is provided in **Figure 40**.

Figure 40: Combined-Cycle Power Plant HRSG



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

Trends and Analysis

The underlying combustion technologies are mature and the prices stable. In addition the uncertainty driven by CF, both CC and CT power plants need to participate in emission credit markets. The trend toward both increasing costs of particulate and volatile emission credits and greenhouse gas emission credits is likely to add significant costs over the lifetime of a fossil-fueled power plant.

Most CC power plants that were built expecting to operate 80 percent of the time or more have seen the actual operation well below this threshold. Instead of base load, these plants have been operated as *load-following*, meaning they ramp up and down through the day tracking the overall trend in electricity demand as consumers respond to cooling, heating, and lighting needs. As a result, the number of CC power plants being built in California recently has declined as more uncertainty in the ability to recover the cost of construction and operation exists.

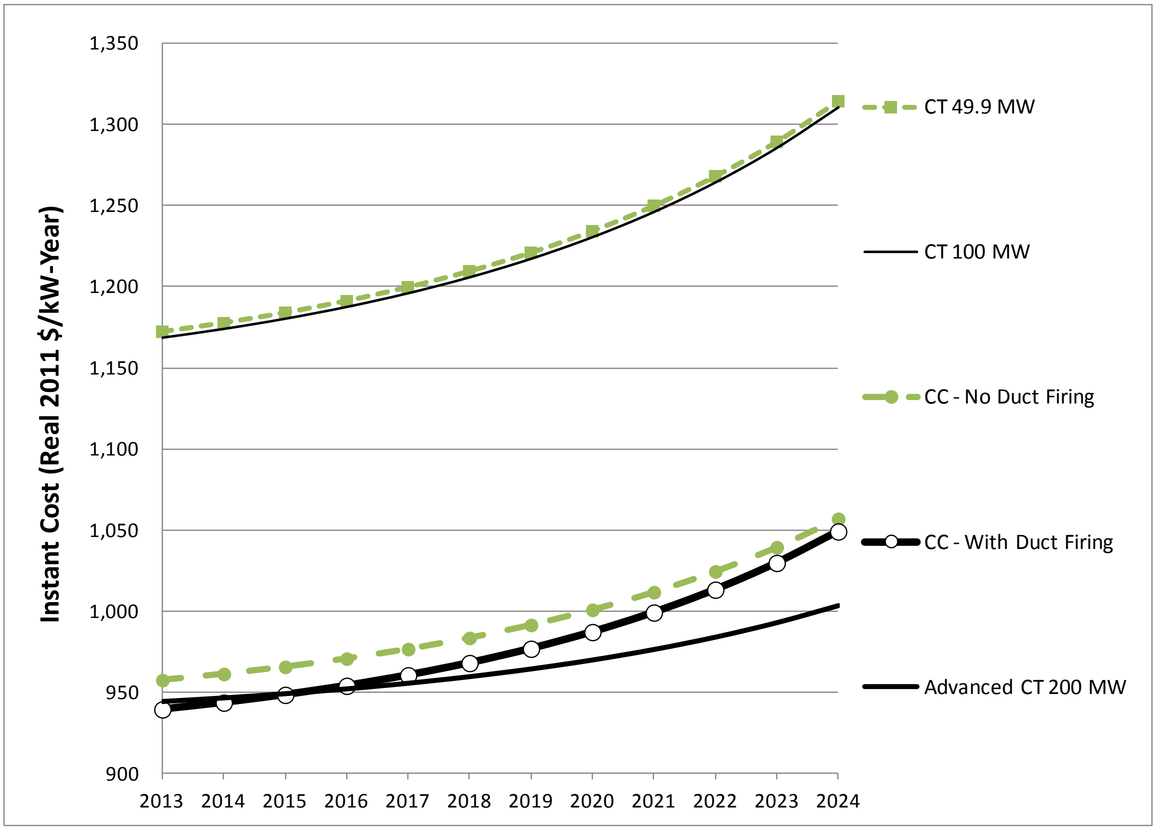
While CT power plants are able to participate in the competitive California ISO marketplace, the majority of the resources owned by IOUs are "self-scheduled," meaning they are given direction to run by the IOU and then must take the market clearing price established by the California ISO marketplace. This has the effect of removing these resources from competition and making the operation of these power plants discretionary on the part of the IOU. Any attempt to speculate why IOU CTs operate in this fashion is beyond the scope of this report but stands as a significant insight from this report.

For this report, staff used actual data in the *QFER* database to accurately represent the CF at which each type of power plant could expect to operate. The counterintuitive result was that the CF of the CT power plants varied by nontrivial amounts among utility ownership types. The difference between publicly owned CTs at 7.5 percent CF and investor-owned combustion turbines at 1 percent CF has significant implications for overall levelized costs.

Instant Cost Trends

The projected costs for the gas-fired technologies are shown if **Figure 41**. Although the real escalation of the equipment costs is assumed to be zero, the instant cost itself escalates due to the increasing ERCs. The real mid case escalation varies in the range of 4 to 10 percent over the period of 2013 to 2024.

Figure 41: Mid Case Instant Costs for Gas-Fired Technologies



Source: Energy Commission.

Summary of Assumptions

Operational Characteristics

To estimate the cost of construction and operation of natural gas-fired plants, it is necessary to define and estimate several physical plant characteristics. These characteristics vary by model and technology. These data generally have been collected through a survey conducted by Energy Commission staff and supported by consultants hired by the Energy Commission. Other sources are noted, where relevant.

Gross Capacity (MW)

Gross capacity is the capacity of the plant prior to any corrections for site losses or degradation. The gross capacity assumed for the five natural gas-fired technologies selected for estimation in the COG Model are provided in **Table 46**.

Table 46: Gross Capacity Ratings for Typical Configurations

Technology Case	Gross Capacity
Conventional CT—One LM6000 Turbine	49.9 MW
Conventional CT—Two LM6000 Turbines	100 MW
Advanced CT—Two LMS100 Turbines	200 MW
Conventional CC (no duct firing)—Two F-Class Turbines	500 MW
Conventional CC (duct firing)—Two F-Class Turbines	550 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 temperatures and that the turbines are assumed to operate the same regardless of elevation.

Capacity Factor

The CFs were determined for the existing California conventional LM6000 CT power plants and F-Class CC power plants based on the historical monthly *QFER* data from 2001 to 2011 for 25 CT facilities and 22 CC facilities. All data are provided in Appendix B.[49]

Seven of the CT units used in the analysis (Anaheim, Glenarm, Grayson, Malaga, MID Ripon, Niland, and Riverside) are owned by POUs, and four (Barre, Center, Etiwanda, and Mira Loma) are owned by IOUs. The other power plants used in the analysis are all merchant facilities.

The CFs for the CC units are based on the annual average capacity for each facility. For duct-fired plants, the duct-fired CF was used. Magnolia (Burbank) and Cosumnes (Sacramento County) power plants are owned by POUs, and the Palomar Energy Center (Escondido, San Diego County) and Mountainview Power Company (San Bernardino County) are owned by IOUs. The other power plants are all merchant facilities. The staff estimated CFs by examining historical CF data in the Energy Commission's *QFER* database (summarized in Appendix B). **Table 47** provides the mid, high, and low case CFs that were used to estimate levelized cost.

49 The CFs were derived using the following simple equation: *QFER net generation (MWh) /(facility generation capacity(MW) x hrs/year) = capacity factor.*

Table 47: Estimated Capacity Factors

Technology Case	Owner	Assumed Capacity Factor		
		Mid Case	High Case	Low Case
Conventional CT (both sizes)	Merchant	5.0%	2.5%	7.0%
	POU	7.5%	4.0%	14.0%
	IOU	1.0%	1.0%	1.0%
Advanced CT	Merchant	7.5%	3.75%	10.50%
	POU	11.25%	6.0%	21.0%
	IOU	1.5%	1.5%	1.5%
Conventional CC	All Owners	57.0%	40.0%	71.0%
Conventional CC w/Duct Burners	All Owners	57.0%	40.0%	71.0%

Source: Energy Commission.

Note: High and low are based on cost implications not on the specific value of the CF.

The CF increases in both CT and CC seen in the *2009 IEPR* (in both the *QFER* and California ISO *Annual Report on Market Issues and Performance)* have reversed in recent years. The recommended CFs for both types of plants are now generally significantly lower than those used in the previous version of the COG Model. The advanced CT CFs were increased 50 percent above the assumed conventional CT CFs due to the assumption of increased use. This assumed higher use is attributed to the higher operational efficiency and supported by the experience of the CTs in the databases.

Plant-Side Losses

The plant-side losses, also referred to as site losses, were estimated by analyzing the same *QFER* database used for calculating CFs, based on monthly data from 2001 to 2008 for CT facilities and CC facilities. The plant-side losses were determined by using the difference in the reported gross vs. reported net generation for the existing California conventional LM6000 CT power plants and F-Class CC power plants. Based on these data, the mid-cost, high-cost, and low-cost plant-side losses are shown in **Table 48**. The advanced CT facilities may have increased plant-side losses due to the power required for the turbine intercooling auxiliary facilities; however, staff has no specific information to obtain values different from those determined for the LM6000 gas turbine facilities used.

Table 48: Summary of Recommended Plant-Side Losses (Percent)

Technology	Mid	High	Low
All CCs	2.9%	4.0%	2.0%
All CTs	3.4%	4.2%	2.3%

Source: Energy Commission.

Heat Rate

The heat rate of a natural gas-fired power plant describes how much natural gas must be burned (measured in Btu) to generate 1 kWh of energy.[50] Higher heat rates are an indication of lower efficiency in converting fuel to electricity. Staff determined heat rates, reported as higher heating value (HHV), for the existing California conventional LM6000 CT power plants and F-Class CC power plants based on the monthly *QFER* data from 2001 to 2011 for 25 CT facilities and 22 CC facilities. The derived heat rates are provided in Appendix B.

Table 49 provides the mid case, high case, and low case heat rates that were determined for use in the COG Model. These values are higher (in other words, less efficient) than those reported by manufacturers and often used in studies because these values include real-world operations reflected in QFER, such as start-ups and load following.

Capacity and Heat Rate Degradation

As a natural gas plant ages, both the capacity and heat rate degrade. These are measured as degradation factors that represent the percentage that the capacity will decrease or that the heat rate will increase per year. These increases are driven by normal wear and tear on the generation turbine but are addressed by maintenance. For this report, the capacity and heat rate degradation factors are assumed to have the same values, which are summarized in **Table 50**.

50 The heat rates were derived using the following simple equation:
QFER heat input (MMBTU)/QFER net generation (kWh) = heat rate (Btu/kWh).

Table 49: Summary of Recommended Heat Rates (Btu/kWh, HHV)

Technology	Mid [a]	High [a]	Low [b]
Conventional CT [c]	10,585	11,890	9,980
Advanced CT	9,880	10,200	9,600
Conventional CC	7,250	7,480	7,030
Conventional CC With Duct Firing	7,250	7,480	7,030

Source: Energy Commission.

Notes: a Mid and high case recommended values are based on an analysis of mid and high *QFER* heat rates and current turbine technology. (For example, the mid case heat rate for the conventional CT is based on new projects installing the next generation of LM6000 gas turbine.)

b Low case recommended values are based on new and clean heat rates from turbine manufacturers. Mid case heat rates in COG Model are presented as a regression formula based on *QFER* data.

c The conventional CT 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.

Table 50: Summary of Capacity and Heat Rate Degradation Factors

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

Source: Energy Commission.

These values were estimated using GE data provided by Energy Commission contractors as part of the survey of available literature. GE's rule of thumb for CTs is that they degrade 3 percent between overhauls[51], which is about every 24,000 hours. The actual time between overhauls, therefore, is a function of CF as shown in **Table 51** or the mid case. **Table 51** shows that the expected book life[52] of the turbines will be exhausted before 24,000 hours of

51 An overhaul represents a complete tearing down and rebuilding of the major turbine elements. This can include replacement of major portions of a turbine or other generation system components.

52 *Book life* is the amount of time a major piece of equipment will have value on which an owner will have to pay taxes. For staff's estimates, it is assumed to be the period of study. It is typically shorter than the useful life of the equipment.

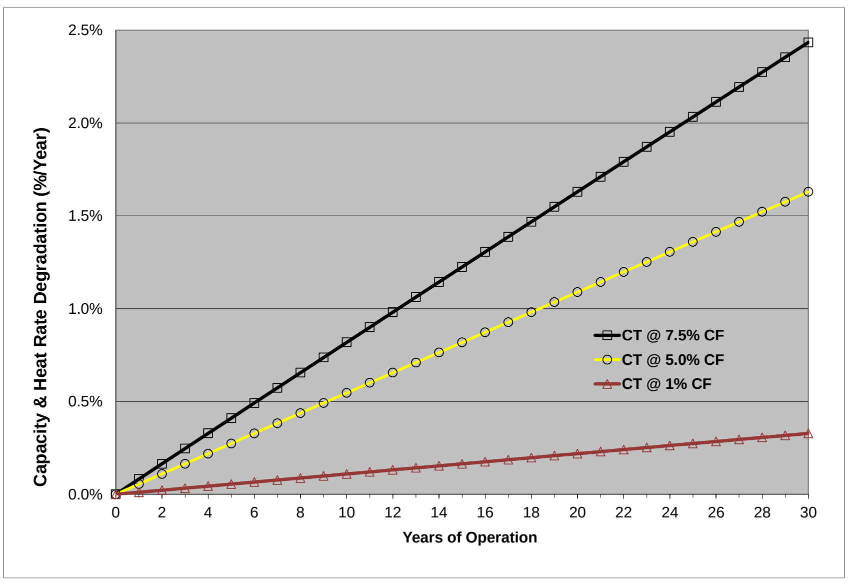
operation is reached and, therefore, shows no overhauls. **Figure 42** shows the degradation pattern for the merchant CT, which is 0.055 percent a year[53]. The IOU and POU degradation factors for combustion turbines are 0.011 percent and 0.082 percent, respectively.

Table 51: Years Between Overhauls vs. Capacity Factor—Mid Case

Technology	Assumed Capacity Factor	Years Between Overhauls
IOU CT	1%	274
Merchant CT	5%	55
POU CT	7.5%	37
Advanced CT	7.5%	37
CC Units	57%	4.8

Source: Energy Commission.

Figure 42: Combustion Turbine Capacity and Heat Rate Degradation—Mid Case



Source: Energy Commission.

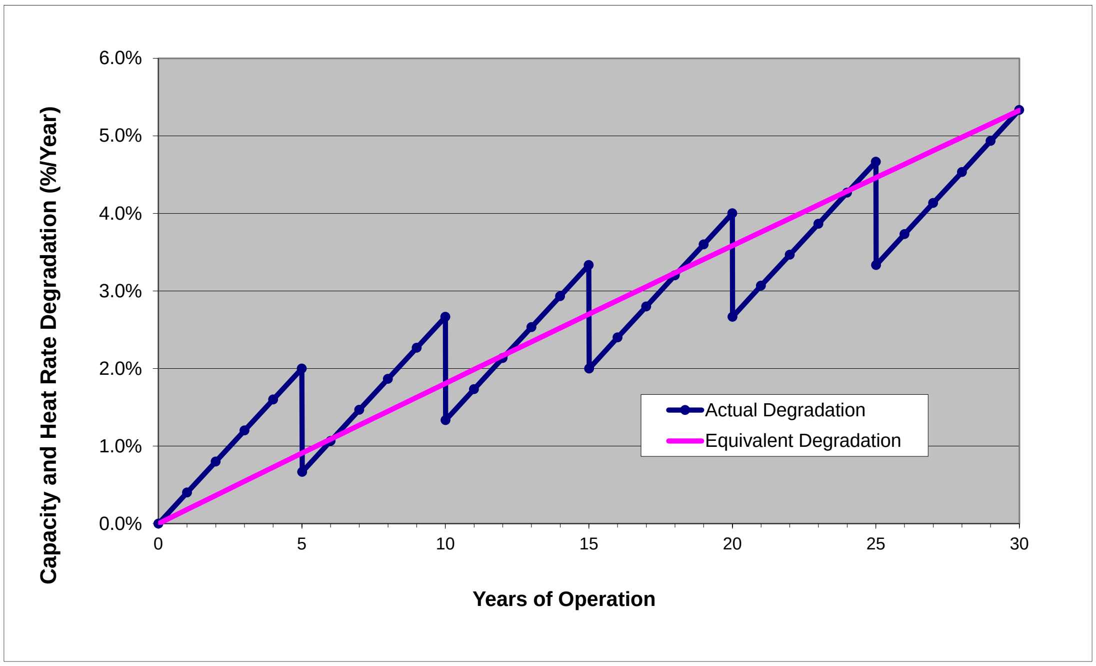
The computation for the CC units is more complex due to the higher CFs, estimated to be above 57 percent for the mid case, which means an overhaul every 4.8 years.[54] Staff

53 The merchant degradation factor is calculated as follows: 1.64%/30 years= 0.055%. The same calculation is used for the IOU and POU degradation factors.

54 This computation translates into one overhaul every 4.8 years through the following calculations: 24,000 hours/(0.57 x 8760 hours per year = 4.8 years).

simplified this assumption to 5 years, which results in five major overhauls during its 30-year book life, as shown in **Figure 43**.[55] The degradation factor is equal to the slope of the equivalent degradation curve, or 0.178 percent per year. There are a number of approximations associated with this estimate, but since this factor has a small effect on levelized cost, these approximations have very little effect on the calculated LCOEs for these natural gas-fired technologies. The details of this process can be found in the *COG Model User's Guide*.

Figure 43: Combined Cycle Heat Rate Degradation—Mid Case



Source: Energy Commission.

Emission Factors

The criteria pollutant emission factors for the four 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 (western Fresno County)

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55 The SC units will degrade 3 percent during each five-year period. Since the steam generator portion is roughly one-third of the system and remains essentially stable, and the overall system deteriorates two-thirds of the 3 percent of the simple cycle during the five-year period, which is 2 percent, and recovers two-thirds of its 2 percent deterioration during the overhaul, which is 1 and 1/3 percent (2/3*2 = 4/3 percent = 1.333 percent).

- Conventional CC (no duct firing)—Carlsbad Energy Center (Carlsbad, San Diego County)
- Conventional CC (duct firing)—Avenal Energy (Avenal, Kings County)

The criteria pollutant emission factors and emissions used in the COG Model to calculate levelized cost are based on these recent projects provided in **Table 52**.

The criteria pollutant emissions are based on permitted rather than actual emissions; therefore, mid, 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.

Table 52: Permitted Emission Factors and Emissions

Technology	NOx	VOC	CO	SOx	PM10
Power Plant Emission Factors (Lbs/MWh)					
Conventional CT[a]	0.279	0.054	0.368	0.013	0.134
Advanced CT	0.099	0.031	0.19	0.008	0.062
Conventional CC	0.070	0.024	0.208	0.005	0.037
Conventional CC w/Duct Firing	0.076	0.018	0.315	0.005	0.042
Power Plant Emissions (Tons/Year)					
Conventional CT 49.9 MW	20.06	3.88	26.46	0.93	9.63
Conventional CT 100 MW	40.20	7.78	53.02	1.87	19.31
Advanced CT	28.45	8.91	54.60	2.30	17.82
Conventional CC	131.56	45.11	390.92	9.40	69.54
Conventional CC w/Duct Firing	157.12	37.21	651.22	10.85	86.83

Source: Energy Commission.

a. The conventional CT values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

The CO_2 emission factors were determined based on the efficiency for each technology based on a natural gas emission factor of 52.87 lb/MMBtu.[56]

Table 53 provides the CO_2 emission factors for each technology case based on the heat rates shown in **Table 49**.

56 The emission factor is from the ARB for natural gas with an assumed heating content (HHV) between 1,000 and 1,025 British thermal units per standard cubic foot (Btu/scf).

Table 53: Estimated Carbon Dioxide Emission Factors (lbs/MWh)

Technology	Mid Case	High Case	Low Case
Conventional CT[a]	1,239.29	1,392.08	1,168.46
Advanced CT	1,156.75	1,194.22	1,123.97
Conventional CC	848.83	875.76	823.07
Conventional CC w/Duct Firing	848.83	875.76	823.07

Source: Energy Commission.

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

The plant costs data for natural gas-fired power plants were obtained from the contractor surveys of power plants in California. Costs are adjusted for the physical performance parameters, and the instant costs are converted to installed costs by the COG Model using the financial parameters described in Chapter 2 of this report. All projects are assumed to have selective catalytic reduction for control of NO_x emissions and an oxidation catalyst for control of carbon monoxide emissions. Instant costs also include acquisition of ERCs. GHG emissions are included in the annual operating costs, not instant costs.

Combined Cycle Capital Costs

The assumed design configurations of the two combined CC cases are 1) a 500 MW plant without duct firing that uses two F-frame turbines with one steam generator, and 2) a 500 MW plant with 50 MW of duct firing (for a total of 550 MW) that also uses two F-frame turbines with one steam generator**.** The projects with announced instant or installed cost data were evaluated to determine the recommended mid, high, and low case values for the two combined CC cases.

Table 54 shows that the estimated instant costs for the two CC configurations for 2011 and are in 2011 dollars. These cost estimates exclude land acquisition, environmental permitting, and air emission reductions credit acquisition, which are incorporated separately into the COG Model and usually vary for local and jurisdictional circumstances.

Table 54: Total Instant Costs for Combined Cycle Cases—Year=2011

Technology Case	Mid Case ($/kW)	High Case ($/kW)	Low Case ($/kW)
Conventional 500 MW CC Without Duct Firing			
Without Ancillary Costs	$841	$857	$699
Interconnection Costs	$61	$135	$39
Land Costs	$4	$9	$1
Licensing Costs	$46	$87	$36
2011 Instant Costs With Ancillary Costs (Nominal $/kW)	**$951**	**$1,089**	**$775**
Conventional 550 MW CC With Duct Firing			
Without Ancillary Costs	$824	$852	$672
Interconnection Costs	$56	$128	$35
Land Costs	$3	$8	$1
Licensing Costs	$49	$90	$39
2011 Instant Costs with Ancillary Costs (Nominal $/kW)	**$933**	**$1,079**	**$747**

Source: Energy Commission.

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

Combustion Turbine Capital Costs

The assumed design configurations of the three CT cases are 1) a 49.9 MW plant that uses one LM6000 gas turbine with chiller air pretreatment, 2) a 100 MW plant that uses two LM6000 gas turbines with chiller air pretreatment, and 3) a 200 MW plant that uses two LMS100 gas turbines with evaporative cooler air pretreatment**.** The projects with announced instant or installed cost data that were evaluated to determine the recommended mid, high, and low capital cost values for the three CT cases.

Table 55 shows the estimated instant costs for the three CT cases in the COG Model, which are for 2011 and are in 2011 dollars. As with the CC data, these costs estimates exclude land acquisition, environmental permitting, and air emission reductions credit acquisition, which are incorporated separately into the COG Model and usually vary for local and jurisdictional circumstances. The advanced CT case cost is based on very limited data for a different advanced gas turbine type.

Table 55: Total Instant Costs for Combustion Turbine Cases—Year=2011

Technology Case	Mid Case ($/kW)	High Case ($/kW)	Low Case ($/kW)
Conventional 49.9 MW CT			
Without Ancillary Costs	$921	$1,100	$622
Interconnection Costs	$159	$403	$95
Land Costs	$8	$22	$4
Licensing Costs	$75	$128	$51
2011 Instant Costs With Ancillary Costs (Nominal $/kW)	**$1,163**	**$1,653**	**$772**
Conventional 100 MW CT			
Without Ancillary Costs	$993	$1,287	$664
Interconnection Costs	$87	$216	$52
Land Costs	$4	$11	$2
Licensing Costs	$75	$128	$51
2011 Instant Costs With Ancillary Costs (Nominal $/kW)	**$1,159**	**$1,642**	**$770**
Advanced 200 MW CT			
Without Ancillary Costs	$738	$975	$430
Interconnection Costs	$152	$338	$97
Land Costs	$2	$5	$1
Licensing Costs	$48	$105	$23
2011 Instant Costs With Ancillary Costs (Nominal $/kW)	**$941**	**$1,423**	**$550**

Source: Energy Commission.

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

Construction Periods

The estimated construction periods used in this report are based on an analysis of the facilities surveyed for the *2007 IEPR* and other known project construction periods. **Table 56** provides the construction periods used in the mid-cost, high-cost, and low-cost scenarios.

Table 56: Summary of Estimated Construction Periods (Months)

Technology	Mid Case	High Case	Low Case
Conventional CC	24	36	20
Conventional CC With Duct Firing	24	36	20
Conventional CT[a]	9	16	4
Advanced CT[b]	15	20	12

Source: Energy Commission.

Notes: a The conventional CT 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.

Construction periods can be influenced by many factors, including whether the site is greenfield or brownfield, the overall complexity of the facility design, the size and location constraints, and a myriad of other factors. The estimated values assume a typical range of factors and do not include extraordinary circumstances.

Fixed and Variable Operating and Maintenance 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 nonstaffing costs. Nonstaffing costs are composed of equipment, regulatory filings, and other direct costs (ODCs).[57]

Variable O&M is composed of the following components:

- Outage Maintenance—Annual maintenance and overhauls and forced outages.
- Consumables Maintenance—Maintenance to repair parts that are designed to wear out (or be "consumed") during normal operations.
- Water Supply Costs—The cost of providing cooling water for plant operations.

Combustion Turbine Operating Costs

Similar to CCs, the operating costs for CT consist of two components: fixed O&M and variable O&M. **Table 57** and **Table 58** summarize the fixed and variable O&M components, respectively. As a practical matter, O&M costs for CTs are independent of CF. As a result CTs are modeled without a variable cost component, leaving O&M composed solely of fixed costs. Costs are for 2011 and are in 2011 dollars.

Fixed O&M is composed of two components: staffing costs and nonstaffing costs. Nonstaffing costs are composed of equipment, regulatory filings, and ODCs. As with the CC fixed costs, staffing costs for CT 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 historical generation. This may be because these costs are driven more by the number of starts than by the hours of operation. For this reason, these costs were placed in fixed costs instead. This practice appears to be consistent with the cost estimates developed by other agencies and analysts.

Variable O&M is composed of the following components: consumables maintenance and water supply costs. O&M costs are assumed to have a real escalation of 0.5 percent per year, primarily reflecting increasing personnel salaries.

57 "Other direct costs" is an accounting category to capture the miscellaneous costs that accrue directly from plant operations and go toward upkeep of the plant.

Table 57: Fixed Operation and Maintenance—Year=2011 (Nominal$)

Technology	Mid Case	High Case	Low Case
Small CT	$26.85	$71.09	$9.44
Conventional CT	$25.95	$69.57	$9.14
Advanced CT	$23.87	$66.11	$8.45
Conventional CC	$32.69	$77.96	$13.04
Conventional CC With Duct Firing	$32.69	$77.96	$13.04

Source: Energy Commission.

Table 58: Variable Operation and Maintenance—Year=2011 (Nominal$)

Technology	Mid Case	High Case	Low Case
Small CT	$0.00	$0.00	$0.00
Conventional CT	$0.00	$0.00	$0.00
Advanced CT	$0.00	$0.00	$0.00
Conventional CC	$0.58	$1.79	$0.18
Conventional CC With Duct Firing	$0.58	$1.79	$0.18

Source: Energy Commission.

Insurance

Insurance is calculated as 0.6 percent of the installed cost for merchant and POU plants. For IOU plants, it is calculated as 0.6 percent of the assessed value of the plant, which is the installed cost minus depreciation. This same value is used for all natural gas-fired technologies and for all three cost cases.

Summary of 2013 Natural Gas-Fired Generation Costs

Table 59 summarizes instant and installed costs for the natural gas-fired technologies for 2013 (nominal dollars). *Installed cost* is the instant cost plus the cost of financing the plant during construction, and development costs (load fees and insurance).

Table 59: Natural Gas-Fired Instant and Installed Costs by Developer

Capital Costs	Instant Costs ($/kW)	Installed Costs ($/kW)		
Year = 2013 (Nominal Dollars)		Merchant	IOU	POU
Mid Case				
Combustion Turbine 49.9 MW	$1,224	$1,310	$1,320	$1,312
Combustion Turbine 100 MW	$1,220	$1,305	$1,316	$1,307
Advanced Combustion Turbine 200 MW	$987	$1,069	$1,085	$1,064
Combined Cycle Without Duct-Firing 500 MW	$1,000	$1,088	$1,107	$1,084
Combined Cycle − Duct-Firing 550 MW	$981	$1,068	$1,085	$1,064
High Case				
Combustion Turbine 49.9 MW	$1,737	$1,941	$1,965	$1,940
Combustion Turbine 100 MW	$1,726	$1,928	$1,952	$1,928
Advanced Combustion Turbine 200 MW	$1,492	$1,700	$1,727	$1,693
Combined Cycle Without Duct-Firing 500 MW	$1,144	$1,316	$1,341	$1,312
Combined Cycle − Duct-Firing 550 MW	$1,134	$1,304	$1,329	$1,301
Low Case				
Combustion Turbine 49.9 MW	$815	$829	$827	$831
Combustion Turbine 100 MW	$812	$827	$825	$828
Advanced Combustion Turbine 200 MW	$579	$598	$601	$595
Combined Cycle Without Duct-Firing 500 MW	$816	$843	$846	$839
Combined Cycle − Duct-Firing 550 MW	$787	$813	$816	$810

Source: Energy Commission.

Table 60 summarizes O&M costs for 2013 (nominal dollars).

Table 60: Natural Gas-Fired Technology Operation and Maintenance Costs

O&M Costs	Fixed O&M ($/kW-yr.)	Variable O&M ($/MWh)	Total O&M	
Year = 2013 (Nominal Dollars)			($/kW-yr.)	($/MWh)
Mid Case				
Combustion Turbine 49.9 MW	$28.39	$0.00	$28.39	$64.81
Combustion Turbine 100 MW	$27.44	$0.00	$27.44	$62.64
Advanced Combustion Turbine 200 MW	$25.24	$0.00	$25.24	$38.41
Combined Cycle Without Duct-Firing 500 MW	$34.56	$0.61	$37.62	$7.54
Combined Cycle − Duct-Firing 550 MW	$34.56	$0.61	$37.62	$7.54
High Case				
Combustion Turbine 49.9 MW	$75.16	$0.00	$75.16	$343.20
Combustion Turbine 100 MW	$73.55	$0.00	$73.55	$335.86
Advanced Combustion Turbine 200 MW	$69.90	$0.00	$69.90	$212.77
Combined Cycle Without Duct-Firing 500 MW	$82.42	$1.89	$89.06	$25.42
Combined Cycle − Duct-Firing 550 MW	$82.42	$1.89	$89.06	$25.42
Low Case				
Combustion Turbine 49.9 MW	$9.98	$0.00	$9.98	$16.28
Combustion Turbine 100 MW	$9.66	$0.00	$9.66	$15.76
Advanced Combustion Turbine 200 MW	$8.93	$0.00	$8.93	$9.71
Combined Cycle Without Duct-Firing 500 MW	$13.79	$0.19	$14.97	$2.41
Combined Cycle − Duct-Firing 550 MW	$13.79	$0.19	$14.97	$2.41

Source: Energy Commission.

CHAPTER 10: Levelized Cost Estimates

The cost data provided in earlier chapters of this report can be used in a number of studies but are most commonly used to produce LCOE studies. LCOE provides a cost metric that investors and planners can use in conjunction with other metrics in determining where to invest from among a range of technology options. Besides cost, electricity system planners must consider environmental, system, and regulatory requirements in deciding what types of new generation to add to the system.

This chapter summarizes the estimated LCOEs for the 19 technologies covered in this report. For the first time, the COG Report presents high and low levelized costs as probabilistic values, in addition to the traditional deterministic single value levelized cost. These high and low costs are developed using Lumina's Analytica Model in conjunction with the Energy Commission's COG Model, designated as ACAT. This chapter also compares LCOE estimates to those from the *2009 IEPR*.

Definition of Levelized Cost

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

The levelized cost formula used in the COG Model first estimates the annual costs over the lifetime of the power plant, then uses a "discount rate" to express all the costs in terms of a single year's dollar value, also referred to as the *net present value*. The model then sums the net present value of the individual cost components and computes the annual payment with interest required to pay off that present value over some specified period, usually the life of the plant.

The levelized cost results are presented as a cost per unit of energy over the period under investigation. This is done by dividing the total costs of the generating unit by the sum of all the expected generation output from that unit over the time horizon being analyzed. The most common presentation of levelized costs is in $/MWh or cents per kilowatt-hour (¢/kWh). A common alternative presentation is in dollars per kilowatt year ($/kW-yr.)

Levelized cost is generated by the COG Model using operational, cost, financial, and tax assumptions described earlier in this report. The COG Model calculates the costs for a technology on an annual basis, finds a present value of those annual costs, and then calculates a levelized cost.

The levelized costs are constructed from the point of view of the developer. They do not reflect any electricity system effects, such as the effect the technology may have on other generation resources or the operational profile of the system. For example, for a natural gas-fired CC unit, a CF has been estimated from historical data, but whether a particular unit at any point in time will realize that CF is uncertain. At the same time, there is uncertainty about the effect the entry of this unit into the system may have on the CFs of the existing CC units—or for that matter, the operation of any existing technology in the system. LCOEs presented in this report assume *ceteris paribus*, or, all other things held constant, for the different cost cases.

Definition of Levelized Cost Components

Levelized costs consist of fixed and variable cost components, as shown in **Table 61**. All these costs vary depending on whether the project is a merchant facility or owned by an IOU or a POU. In addition, the costs can vary with location because of differing costs of land, fuel, construction, operational, and environmental licensing.

Table 61: Summary of Levelized Cost Components

Fixed Costs
Capital and Financing—The total cost of all equipment and construction, including financing the plant
Insurance—The cost of insuring the power plant
Ad Valorem—Property taxes
Fixed O&M—Staffing and other costs independent of operating hours
Corporate Taxes—State and federal taxes
Variable Costs
Fuel Cost—The cost of the fuel used
GHG Cost—Cap-and-trade allowance costs
Variable O&M—Operation and maintenance costs that are a function of operating hours
Total Costs
Total Cost = Fixed Cost + Variable Cost

Source: Energy Commission.

Capital and Financing Costs

The capital cost includes the total costs of all equipment and construction, including land purchase and development; permitting, including ERCs; the power plant equipment; interconnection, including transmission; and environmental control equipment. The financing costs are those incurred through debt and equity financing by the developer annually, similar to financing a home. The annual costs are irregular, generally front-loaded, and levelized in this cost structure.

Insurance Cost

Insurance is the cost of insuring the power plant, similar to insuring a home. For a merchant or POU plant, the first-year cost is estimated as a percentage of the installed cost and is then escalated by inflation throughout the book life of the power plant. For an IOU plant, the annual costs are a percentage of the book value in each year.[58]

Ad Valorem

Ad valorem costs are annual property taxes 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 IOU power plants are set by the State Board of Equalization as a percentage of book value and as depreciation-factored value for a merchant facility.

Fixed Operating and Maintenance

Fixed 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. The first-year cost is provided as an estimate and then escalated by inflation plus 0.5 percent real escalation.

Corporate Taxes

Corporate taxes are state and federal taxes on revenues or earnings, which are not applicable to a POU. Due to differences in eligibility for tax incentives, the calculation can differ between merchant and IOU owners. Neither calculation method lends itself to a simple explanation, but in general, the taxes depend on net operating income depreciated values and are adjusted for interest on debt payments and depreciation. The federal taxes are adjusted for the state taxes, similar to an adjustment for a homeowner.

58 *Book value* is the net of all assets less all liabilities.

Fuel Cost

Fuel cost is the cost of fuel, such as biomass or natural gas, most commonly expressed in $/MWh, and is estimated for each year of the study. For a thermal power plant, it is the heat rate (in Btu/kWh) multiplied by the cost of the fuel (in dollars per million Btu [$/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 the heat rate of a power plant over time, assuming maintenance and periodic overhauls. The COG Model relies on the *average annual* heat rate, rather than a *full load* or otherwise *optimal operation* heat rate, which is commonly quoted in vendor specifications.

Greenhouse Gas Cost

GHG costs are represented by the allowance prices under the ARB's California's Cap-and-Trade Program multiplied by the average GHG emission rate per MWh. The method for forecasting these costs is discussed in Chapter 3.

Variable Operations and Maintenance Cost

Variable O&M costs are a function of the number of hours a power plant operates. Most important, these costs include yearly maintenance and overhauls. Variable O&M also includes repairs from forced outages, consumables (nonfuel products), water supply, and annual environmental costs.

Summary of Estimated Levelized Costs

Table 62 summarizes mid case levelized costs for the 19 generation technologies by developer (merchant owners, IOUs, and POUs). The levelized costs are provided in $/kW-yr., $/MWh, and ¢/kWh. All costs are in 2013 dollars and are for generation units that began operation in 2013.

Table 63 shows the corresponding estimates for the technologies beginning operation in 2024, in nominal (2024) dollars. **Figure 44** and **Figure 45** show the $/MWh LCOEs as graphs.

In general, merchant and POU renewable plants have lower LCOEs than the IOU plants. For merchant plants, this is due to tax credits. For the POU plants, this is largely due to lower financing costs and an exemption from property taxes. For the gas-fired units, the differences are driven by cost of financing and CFs. CT units are driven largely by CFs, where the IOUs have extremely high LCOEs, driven by very small CFs (as low as 1 percent).

Table 62: Summary of Mid Case Levelized Costs (LCOE)—Start-Year=2013

Start-Year = 2013 (Nominal $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr.	$/MWh	¢/kWh	$/kW-Yr.	$/MWh	¢/kWh	$/kW-Yr.	$/MWh	¢/kWh
Generation Turbine 49.9 MW	49.9	275.66	662.81	66.28	185.13	2215.54	221.55	193.34	311.27	31.13
Generation Turbine 100 MW	100	273.83	660.52	66.05	183.47	2202.75	220.28	191.81	309.78	30.98
Generation Turbine − Advanced 200 MW	200	252.33	403.83	40.38	159.41	1266.91	126.69	200.67	215.53	21.55
Combined Cycle − 2 CTs No Duct Firing 500 MW	500	551.42	116.51	11.65	495.20	104.54	10.45	482.63	102.32	10.23
Combined Cycle − 2 CTs With Duct Firing 550 MW	550	548.14	115.81	11.58	492.86	104.05	10.40	481.32	102.04	10.20
Biomass Fluidized Bed Boiler 50 MW	50	812.34	122.04	12.20	941.97	141.53	14.15	820.03	123.51	12.35
Geothermal Binary 30 MW	30	561.31	90.63	9.06	743.97	120.21	12.02	519.74	84.98	8.50
Geothermal Flash 30 MW	30	653.36	112.48	11.25	851.61	146.72	14.67	627.91	109.47	10.95
Solar Parabolic Trough W/O Storage 250 MW	250	329.92	168.18	16.82	448.52	228.73	22.87	325.42	167.93	16.79
Solar Parabolic Trough With Storage 250 MW	250	405.52	127.40	12.74	601.76	189.12	18.91	423.90	134.81	13.48
Solar Power Tower W/O Storage 100 MW	100	342.48	152.58	15.26	471.26	210.04	21.00	336.00	151.53	15.15
Solar Power Tower With Storage 100 MW 6 HRs	100	421.46	145.52	14.55	630.53	217.79	21.78	440.07	153.81	15.38
Solar Power Tower With Storage 100 MW 11 HRs	100	459.85	114.06	11.41	692.04	171.72	17.17	479.73	120.45	12.05
Solar Photovoltaic (Thin-Film) 100 MW	100	206.11	111.07	11.11	315.22	170.00	17.00	219.97	121.30	12.13
Solar Photovoltaic (Single Axis) 100 MW	100	241.22	109.00	10.90	365.48	165.22	16.52	254.52	116.57	11.66
Solar Photovoltaic (Thin-Film) 20 MW	20	224.21	121.31	12.13	344.46	186.51	18.65	239.16	132.42	13.24
Solar Photovoltaic (Single Axis) 20 MW	20	259.52	117.74	11.77	394.71	179.16	17.92	273.72	125.86	12.59
Wind - Class 3 100 MW	100	181.75	85.12	8.51	223.75	104.74	10.47	160.77	75.80	7.58
Wind - Class 4 100 MW	100	173.08	84.31	8.43	213.61	103.99	10.40	153.55	75.29	7.53

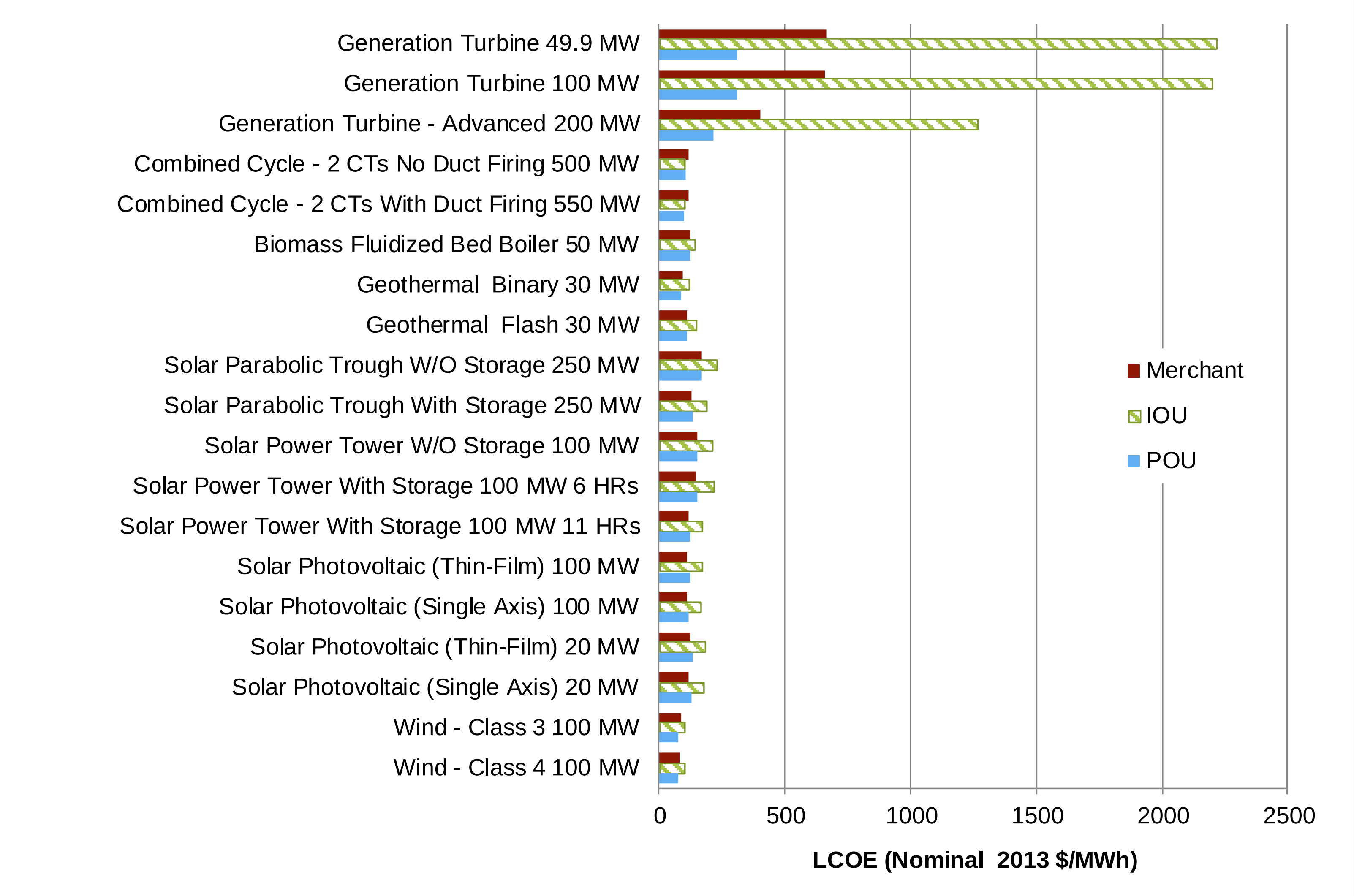
Source: Energy Commission.

Table 63: Summary of Mid Case Levelized Costs—Start-Year=2024

Start-Year = 2024 (Nominal $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr.	$/MWh	¢/kWh	$/kW-Yr.	$/MWh	¢/kWh	$/kW-Yr.	$/MWh	¢/kWh
Generation Turbine 49.9 MW	49.9	367.76	884.24	88.42	241.98	2895.90	289.59	265.97	428.20	42.82
Generation Turbine 100 MW	100	365.50	881.62	88.16	239.93	2880.53	288.05	264.06	426.48	42.65
Generation Turbine − Advanced 200 MW	200	333.15	533.17	53.32	203.29	1615.68	161.57	278.44	299.06	29.91
Combined Cycle − 2 CTs No Duct Firing 500 MW	500	792.57	167.46	16.75	719.44	151.88	15.19	707.86	150.07	15.01
Combined Cycle − 2 CTs With Duct Firing 550 MW	550	790.29	166.97	16.70	717.81	151.54	15.15	706.96	149.88	14.99
Biomass Fluidized Bed Boiler 50 MW	50	1024.35	153.89	15.39	1185.07	178.06	17.81	1037.30	156.23	15.62
Geothermal Binary 30 MW	30	679.29	109.68	10.97	899.30	145.31	14.53	629.94	103.00	10.30
Geothermal Flash 30 MW	30	836.66	144.03	14.40	1078.71	185.85	18.59	816.96	142.43	14.24
Solar Parabolic Trough W/O Storage 250 MW	250	306.21	156.10	15.61	411.25	209.72	20.97	303.64	156.69	15.67
Solar Parabolic Trough With Storage 250 MW	250	372.09	116.90	11.69	545.16	171.34	17.13	389.66	123.92	12.39
Solar Power Tower W/O Storage 100 MW	100	299.95	133.63	13.36	413.39	184.24	18.42	294.22	132.69	13.27
Solar Power Tower With Storage 100 MW 6 HRs	100	384.56	132.78	13.28	568.80	196.47	19.65	402.22	140.58	14.06
Solar Power Tower With Storage 100 MW 11 HRs	100	417.51	103.56	10.36	621.69	154.26	15.43	436.30	109.55	10.95
Solar Photovoltaic (Thin-Film) 100 MW	100	150.44	81.07	8.11	220.85	119.10	11.91	161.24	88.91	8.89
Solar Photovoltaic (Single Axis) 100 MW	100	217.95	98.49	9.85	323.41	146.20	14.62	230.50	105.56	10.56
Solar Photovoltaic (Thin-Film) 20 MW	20	172.08	93.11	9.31	255.86	138.54	13.85	184.21	101.99	10.20
Solar Photovoltaic (Single Axis) 20 MW	20	239.82	108.81	10.88	358.42	162.68	16.27	253.47	116.56	11.66
Wind - Class 3 100 MW	100	160.27	75.01	7.50	196.33	91.90	9.19	144.58	68.17	6.82
Wind - Class 4 100 MW	100	155.67	75.77	7.58	190.77	92.88	9.29	140.37	68.83	6.88

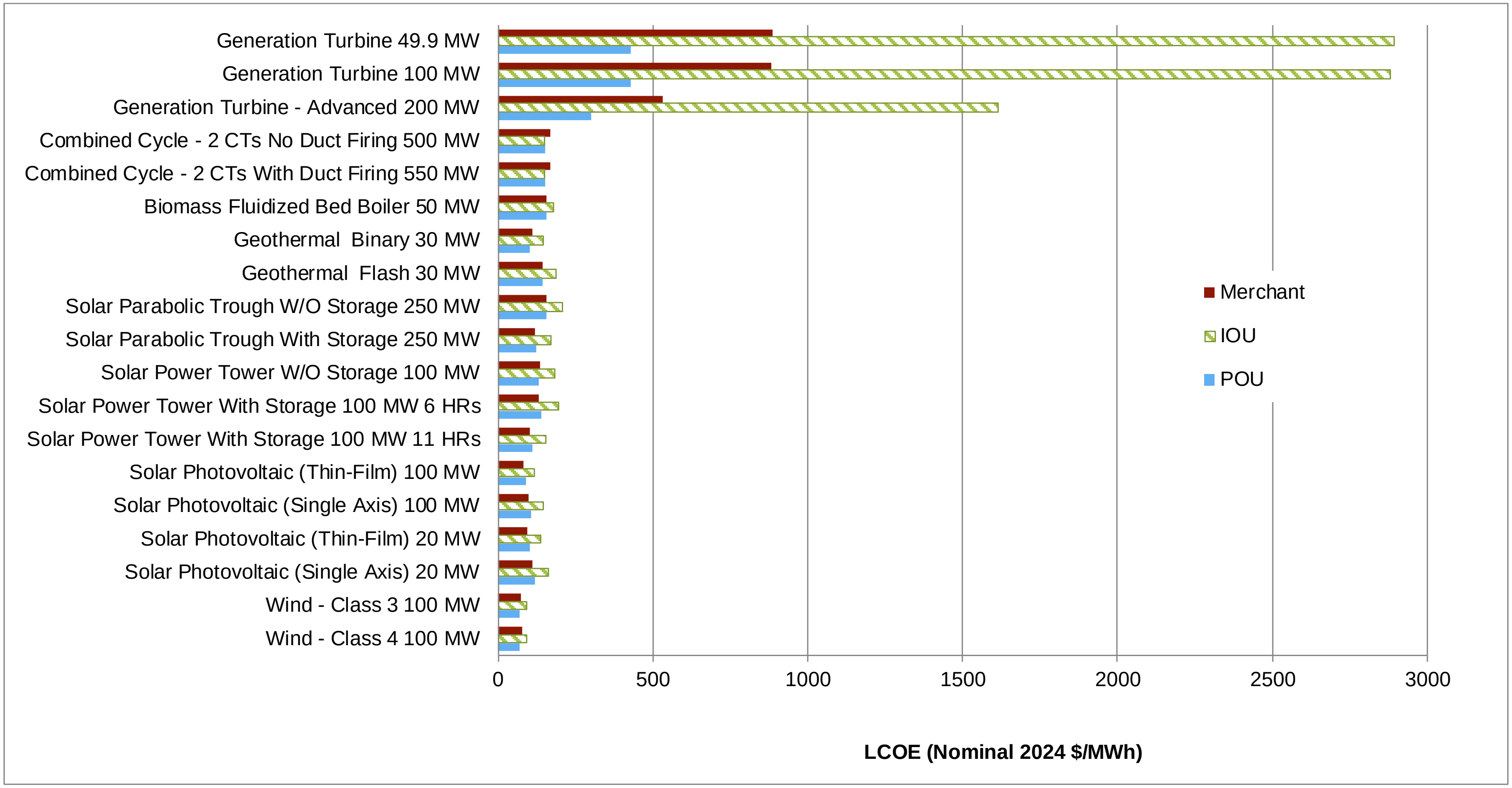
Source: Energy Commission.

Figure 44: Summary of Mid Case Levelized Costs (LCOE)—Start-Year=2013



Source: Energy Commission.

Figure 45: Summary of Mid Case Levelized Costs—Start-Year= 2024



Source: Energy Commission.

Component Levelized Costs

Table 64 provides the corresponding component LCOEs for the singular case of merchant financing of the technologies beginning operation in 2013. **Appendix E** provides the component costs for all three developers for plants beginning operation in 2013 and 2024, both in $/MWh and $/kW-yr.

Levelized Cost Trends—2013 – 2024

Figure 46 shows the merchant LCOE trends in solar technologies in real 2011 dollars. The current tax benefits are assumed to continue over the life of the study. It is striking that technology LCOE spreads over a very large range, with solar PV thin-film 100 MW the least cost, and solar parabolic trough being the most expensive.

Figure 47 shows the merchant LCOE trends for nonsolar renewable technologies. Biomass has the highest LCOE and wind the lowest.

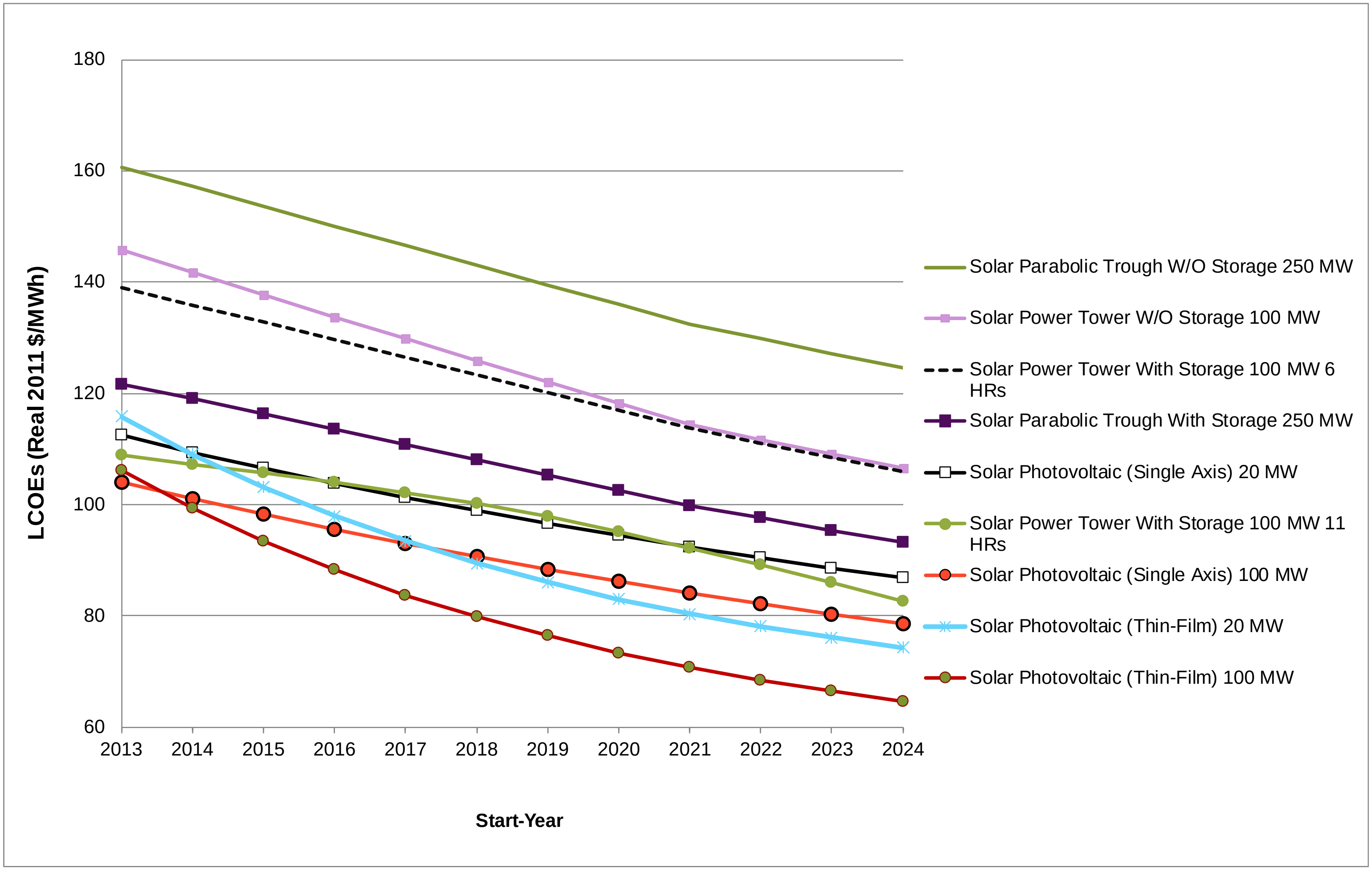
Figure 48 shows the merchant LCOE trends in the natural gas-fired technologies. The increasing penetration of advanced CTs in California can largely be attributed to its cost advantage, as it falls about halfway between the CTs and the CCs.

Table 64: Mid Case Component LCOE for Merchant Financed Plants—Start Year=2013

		$/MWh (Nominal 2013$)									
Start-Year = 2013 (Nominal $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE At Interconnection Point**
Generation Turbine 49.9 MW	49.9	325.78	22.33	32.38	85.38	94.28	**560.14**	102.66	0.00	**102.66**	**662.81**
Generation Turbine 100 MW	100	325.73	22.32	32.37	82.78	94.32	**557.52**	102.99	0.00	**102.99**	**660.52**
Generation Turbine - Advanced 200 MW	200	176.79	12.13	17.60	50.52	51.11	**308.15**	95.67	0.00	**95.67**	**403.83**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	24.16	1.63	2.36	9.13	7.98	**45.27**	70.44	0.79	**71.23**	**116.51**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	23.70	1.60	2.32	9.13	7.83	**44.58**	70.44	0.79	**71.23**	**115.81**
Biomass Fluidized Bed Boiler 50 MW	50	62.70	5.34	7.88	19.71	-24.51	**71.12**	44.06	6.86	**50.91**	**122.04**
Geothermal Binary 30 MW	30	89.16	7.64	11.27	17.90	-35.35	**90.63**	0.00	0.00	**0.00**	**90.63**
Geothermal Flash 30 MW	30	104.13	8.92	13.16	19.08	-41.24	**104.05**	8.43	0.00	**8.43**	**112.48**
Solar Parabolic Trough W/O Storage 250 MW	250	172.96	7.63	12.35	44.73	-69.49	**168.18**	0.00	0.00	**0.00**	**168.18**
Solar Parabolic Trough With Storage 250 MW	250	152.44	6.73	1.98	27.57	-61.31	**127.40**	0.00	0.00	**0.00**	**127.40**
Solar Power Tower W/O Storage 100 MW	100	165.05	7.27	11.78	34.61	-66.13	**152.58**	0.00	0.00	**0.00**	**152.58**
Solar Power Tower With Storage 100 MW 6 HRs	100	178.88	7.89	2.32	28.29	-71.86	**145.52**	0.00	0.00	**0.00**	**145.52**
Solar Power Tower With Storage 100 MW 11 HRs	100	142.95	6.31	1.86	20.32	-57.38	**114.06**	0.00	0.00	**0.00**	**114.06**
Solar Photovoltaic (Thin-Film) 100 MW	100	143.71	6.38	1.88	17.62	-58.51	**111.07**	0.00	0.00	**0.00**	**111.07**
Solar Photovoltaic (Single Axis) 100 MW	100	141.04	6.22	1.83	16.54	-56.64	**109.00**	0.00	0.00	**0.00**	**109.00**
Solar Photovoltaic (Thin-Film) 20 MW	20	159.27	7.06	2.08	17.69	-64.79	**121.31**	0.00	0.00	**0.00**	**121.31**
Solar Photovoltaic (Single Axis) 20 MW	20	154.22	6.80	2.00	16.61	-61.90	**117.74**	0.00	0.00	**0.00**	**117.74**
Wind - Class 3 100 MW	100	80.24	6.85	10.02	0.00	-24.19	**72.92**	0.00	12.20	**12.20**	**85.12**
Wind - Class 4 100 MW	100	79.56	6.80	9.94	0.00	-24.19	**72.10**	0.00	12.20	**12.20**	**84.31**

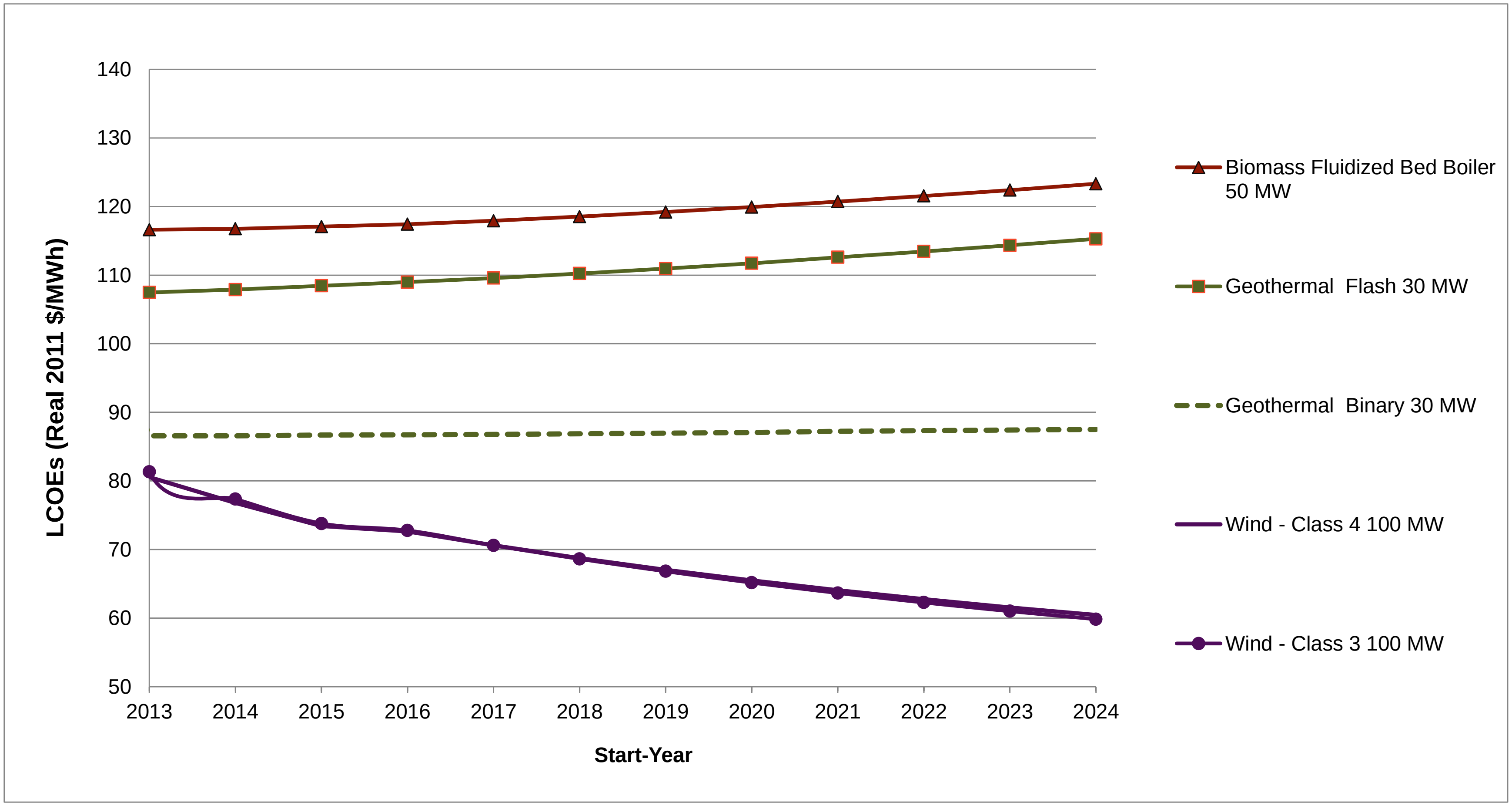
Source: Energy Commission.

Figure 46: Merchant Mid Case Levelized Costs for Solar Technologies



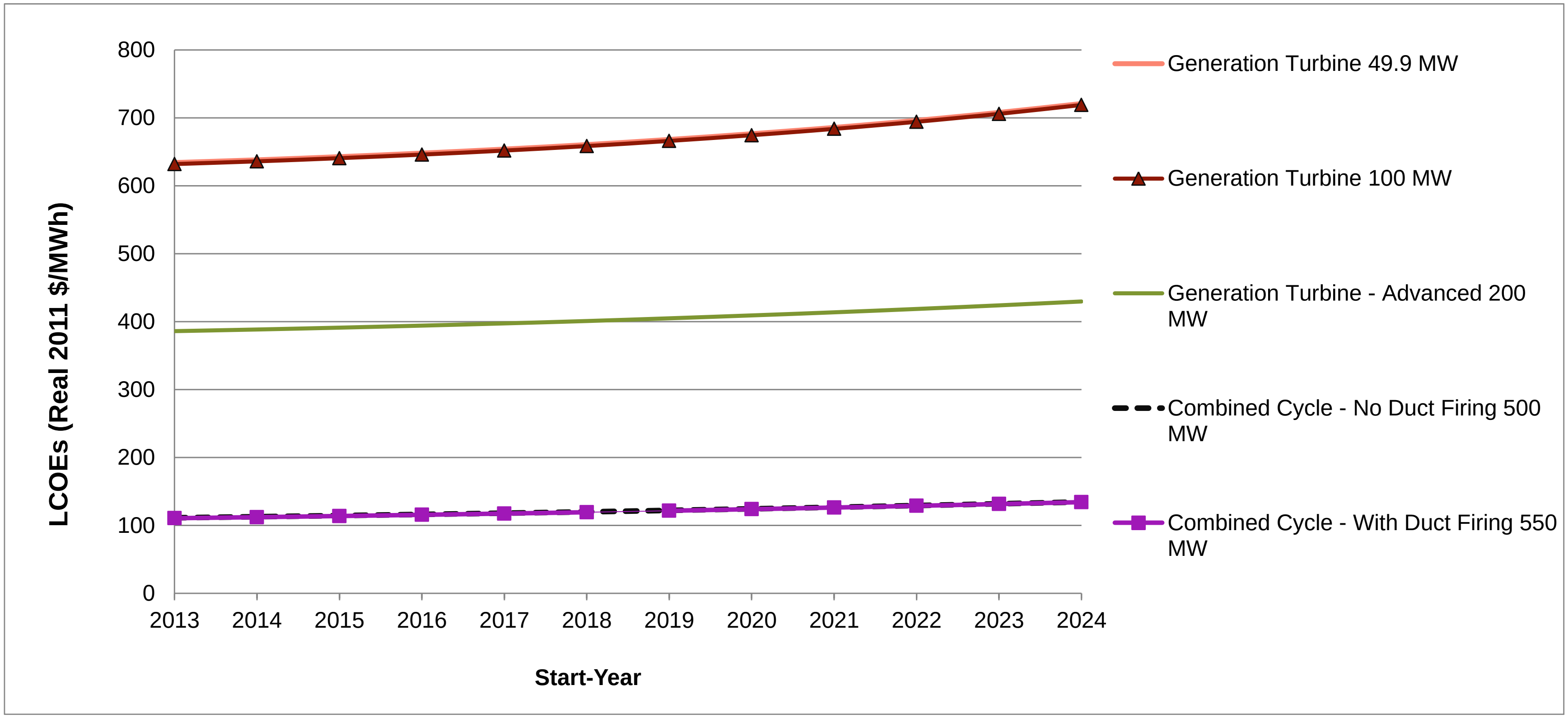
Source: Energy Commission.

Figure 47: Merchant Mid Case Levelized Costs for Nonsolar Renewable Technologies



Source: Energy Commission.

Figure 48: Merchant Mid Case Levelized Costs for Natural Gas-Fired Technologies

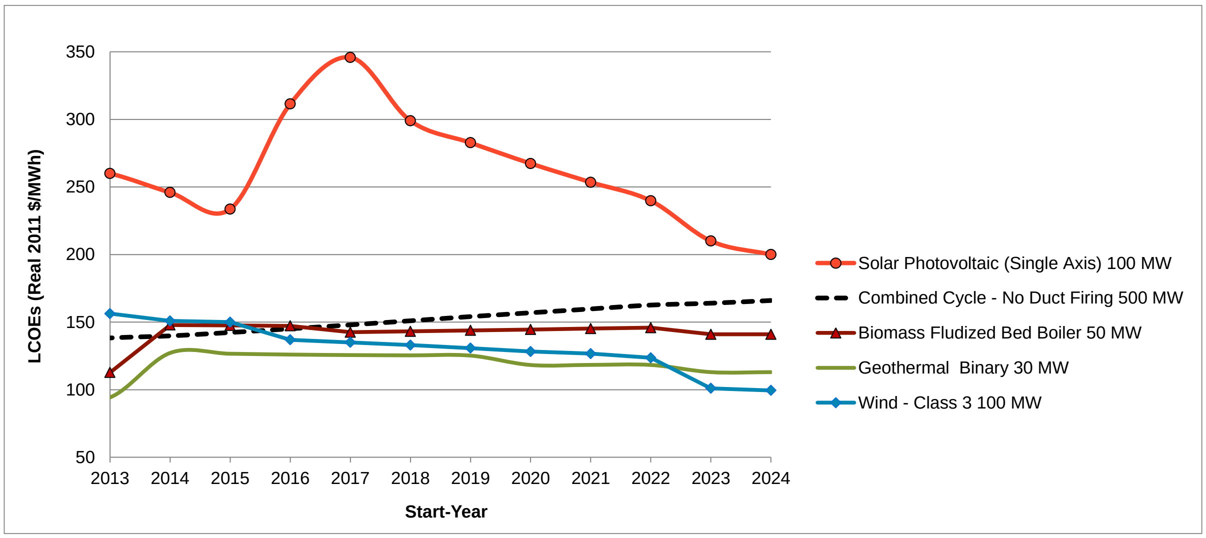


Source: Energy Commission.

Improvement in Solar Photovoltaic Levelized Cost

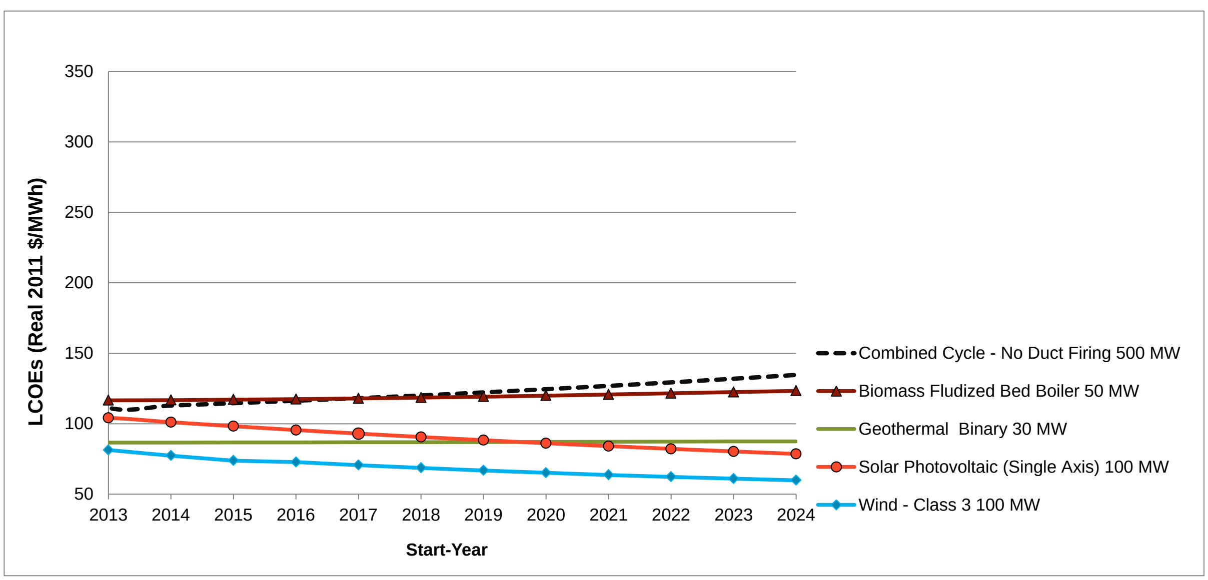
Solar PV levelized costs have improved dramatically since the last assessment in the *2009 IEPR*. **Figure 49** shows the *2009 IEPR* LCOEs for selected technologies. **Figure 50** shows those same technologies for the current LCOE forecast. Solar is now highly competitive in all years, but this comparison relies in part on tax benefits. **Appendix A** delineates the effect of tax benefits on LCOE. **Figure 51** compares the range of the current solar PV 100 MW to that of the 500 MW natural gas-fired CC, showing the lower potential cost of the solar unit – albeit based on deterministic LCOEs.

Figure 49: Levelized Cost of Energy for Selected Technologies—*2009 IEPR Forecast*



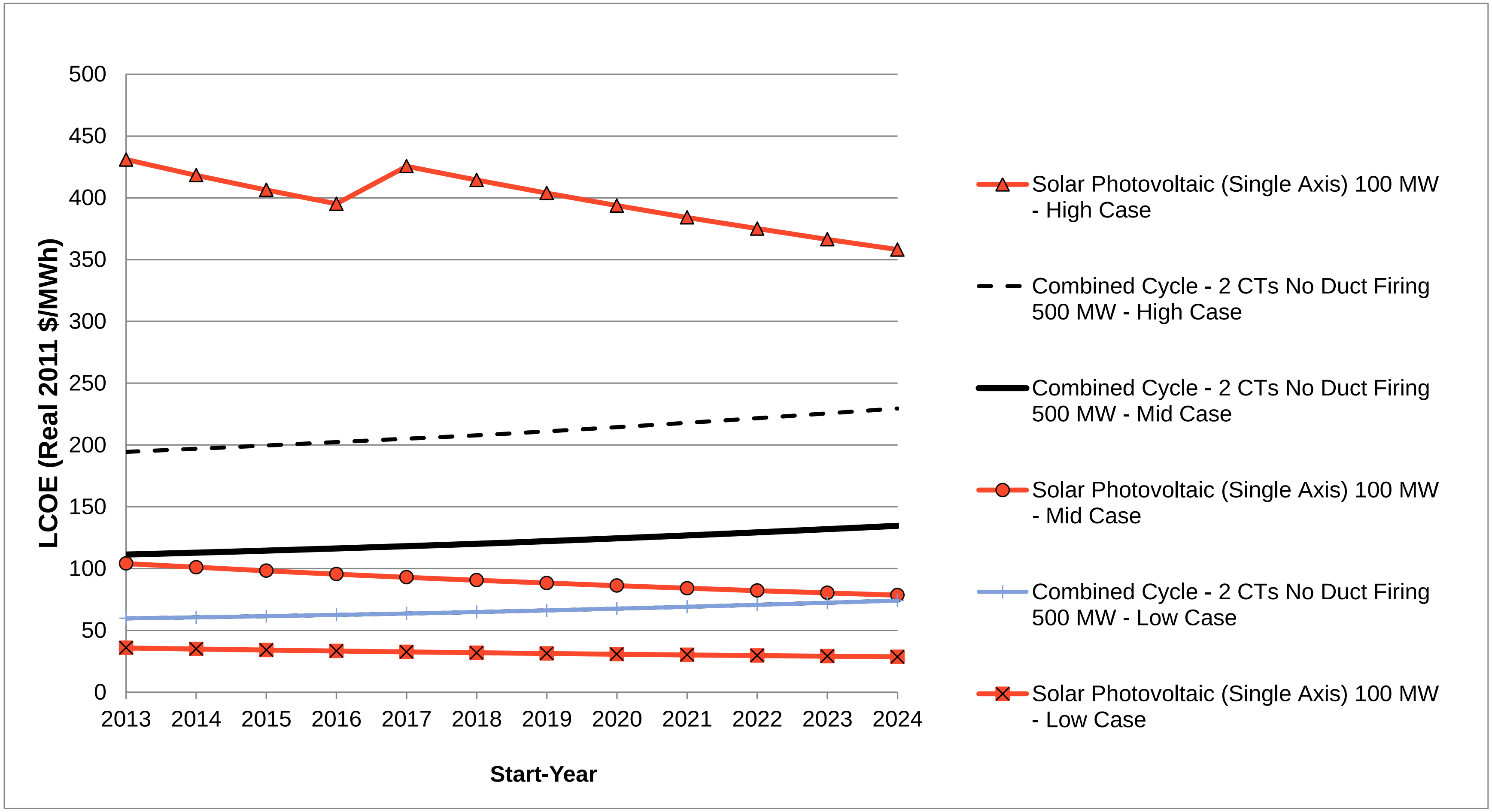
Source: Energy Commission.

Figure 50: Levelized Cost of Energy for Selected Technologies—Current Forecast



Source: Energy Commission.

Figure 51: Comparing Levelized Cost of Energy Ranges for Combined-Cycle 500 MW and Solar Photovoltaic Single-Axis 100 MW



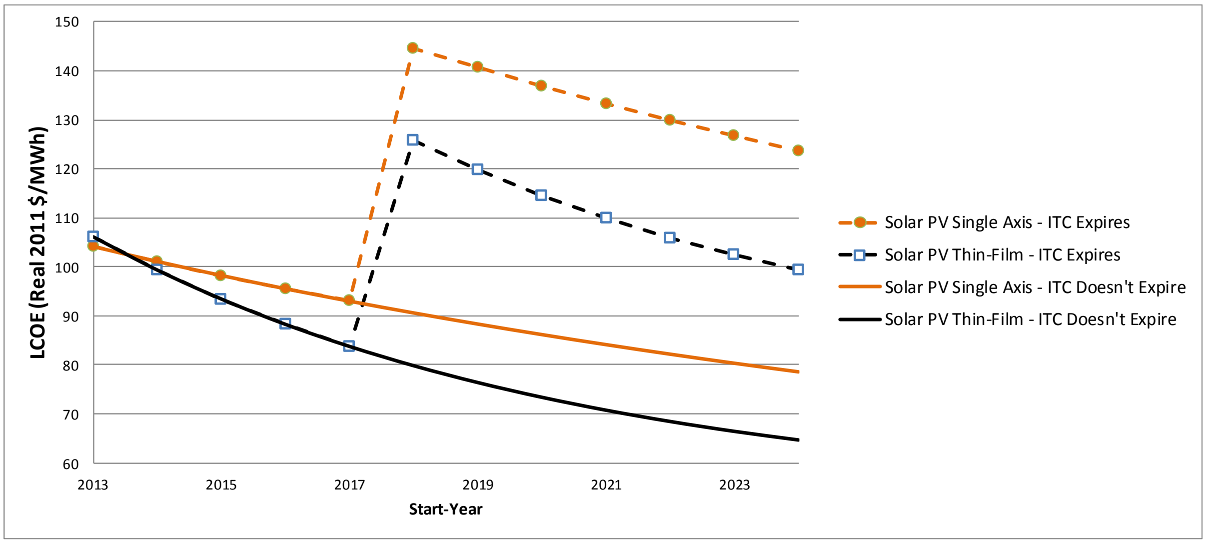
Source: Energy Commission.

Effect of Tax Credits on LCOE

The cost of a technology, as measured as LCOE, will be determined to a large degree by the tax credits it receives. For example, there are two key tax credits: the ITC,[59] which affects solar technologies, and the PTC,[60] which affects wind technologies.

The market suggests that the ITC will be extended past its December 31, 2016, expiration, as shown in **Figure 52**. If not, the ITC of 30 percent for solar PV technologies will decrease to 10 percent. Sites that have broken ground before the expiration are eligible for the incentive. The effect of the ITC on 100 MW solar PV technologies, including a year for development lag time, is shown in **Figure 52**.

Figure 52: The Effect of the Investment Tax Credit on 100 MW Solar PV Technologies



Source: Energy Commission.

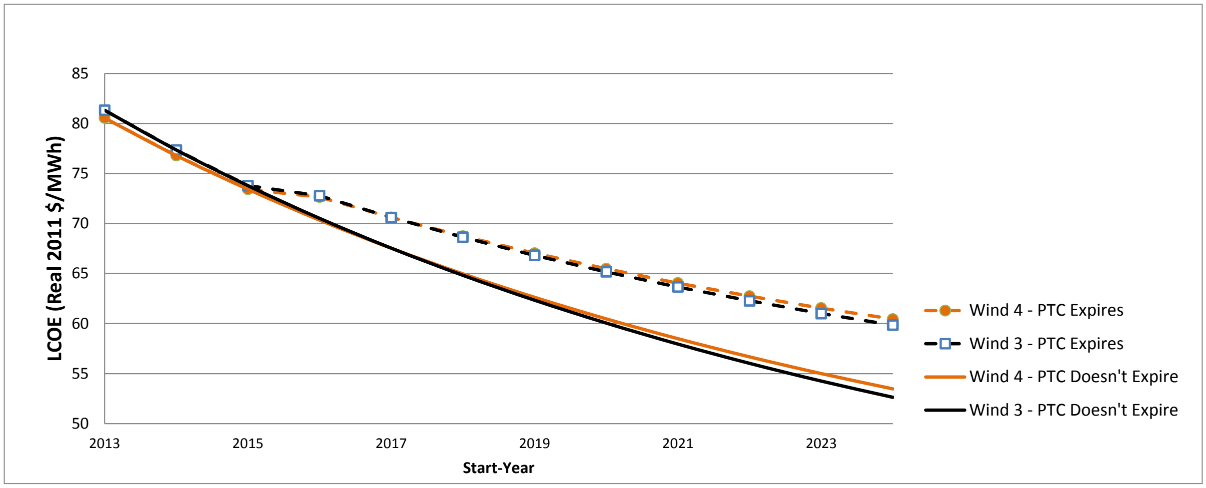
The PTC that affects the levelized cost of wind technologies expired on December 31, 2013.[61] However, projects that have broken ground before that date are eligible and may still be in development. The incentive for wind is $21/MWh, as shown in **Table 11**. The effect of the expiration of this incentive on levelized cost of wind technologies is shown in **Figure 53** and is to be compared against **Figure 52**.

59 Business ITC, see http://www.dsireusa.org (updated 4/2009).

60 Renewable Electricity PTC, see http://www.dsireusa.org.

61 Legislation enacted on December 19, 2013, extended the PTC expiration to December 31, 2014.

Figure 53: The Effect of Tax Credits on 100 MW Wind Technologies



Source: Energy Commission.

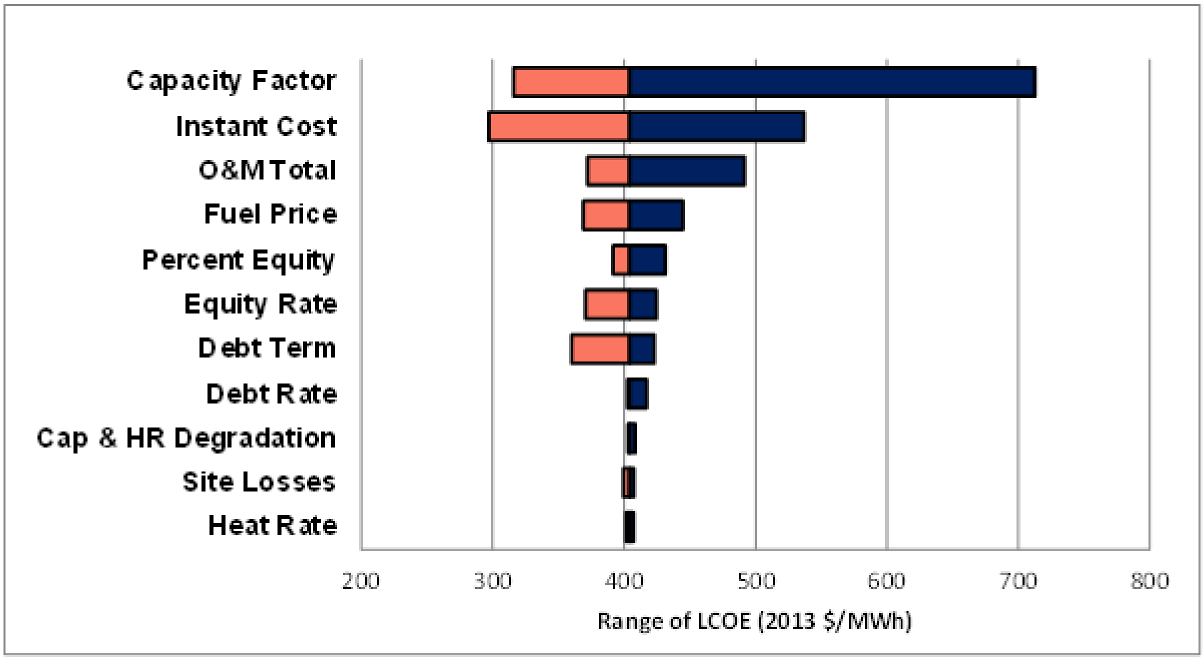
Significant Drivers of Levelized Cost

A key part of estimating a range of levelized costs is identifying the factors that influence these costs. Staff identified 11 significant drivers, illustrated for selected technologies in **Figure 54**, **Figure 55**, and **Figure 56**.[62] The technologies shown highlight how the drivers change in order of significance depending on the technology selected. Each shows the range of LCOE that is caused by the respective drivers for the start year 2013. These representations of the ranges of costs are referred to as "tornado diagrams," due to the appearance. **Appendix C** provides tornado diagrams for all 19 technologies.

The midpoints of these tornado diagrams are not the same as the COG deterministic mid cases. The tornado midpoints are the median (middle) value resulting from the probabilistic draws and cannot be expected to match the mid case values.

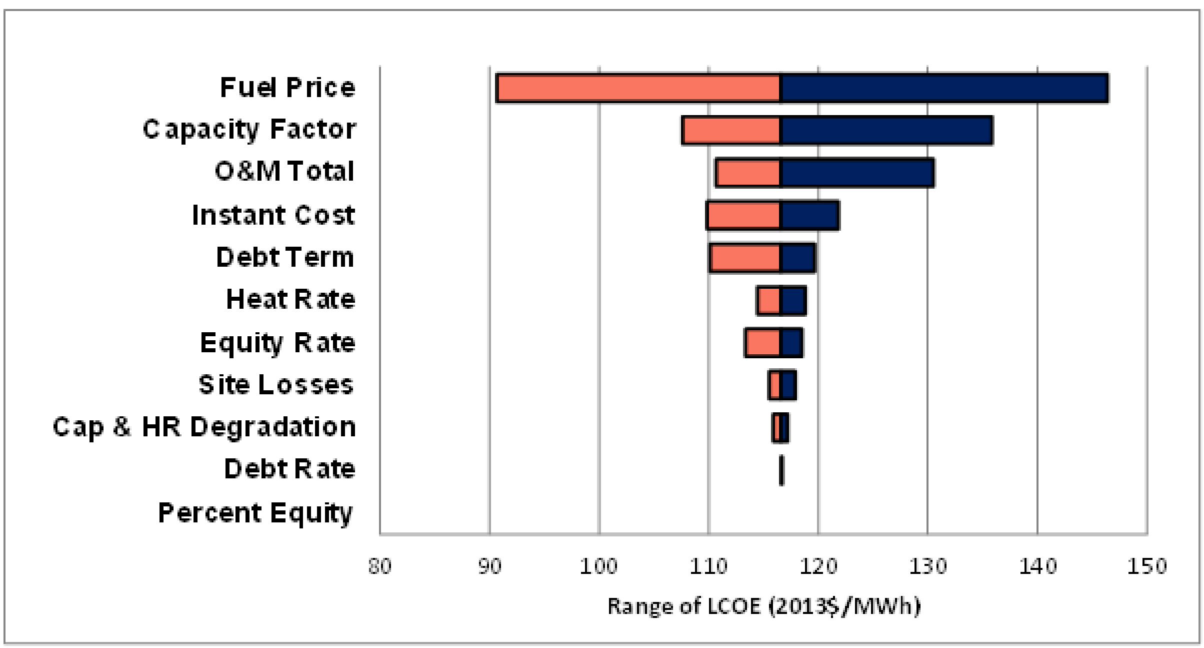
62 *Cap & HR degradation* denotes capacity and heat rate degradation. It captures the effect of how capacity and heat rate degrade over the life of the power plant.

Figure 54: Tornado Diagram—Advanced Generation Turbine—Year = 2013



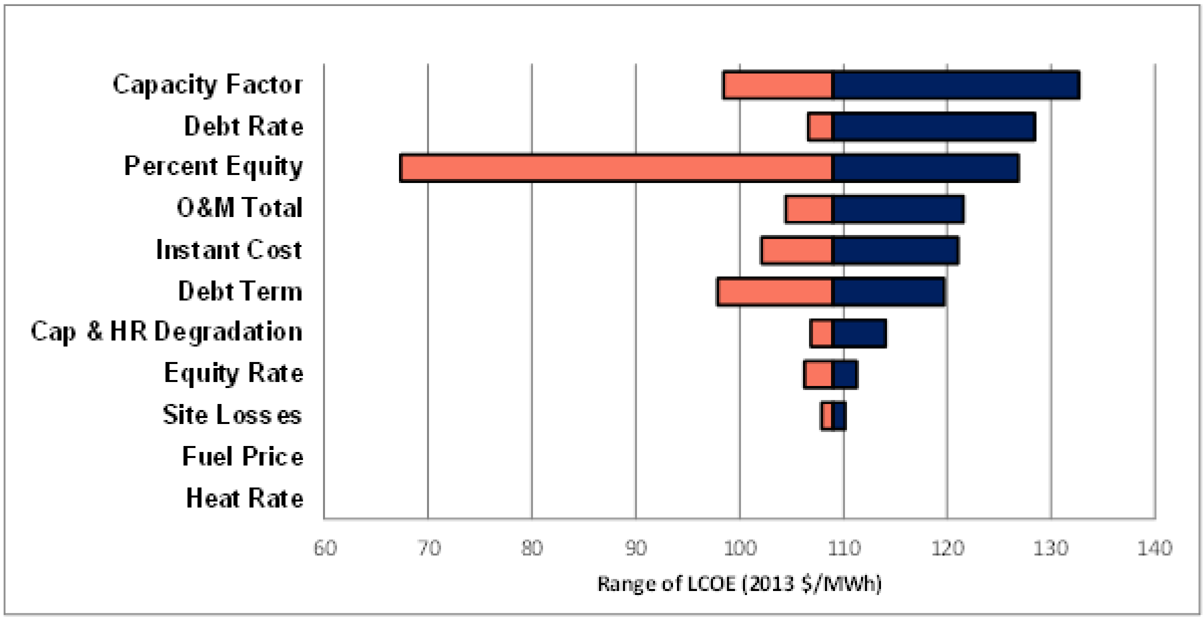
Source: Energy Commission.

Figure 55: Tornado Diagram—Combined Cycle 500 MW—Year = 2013



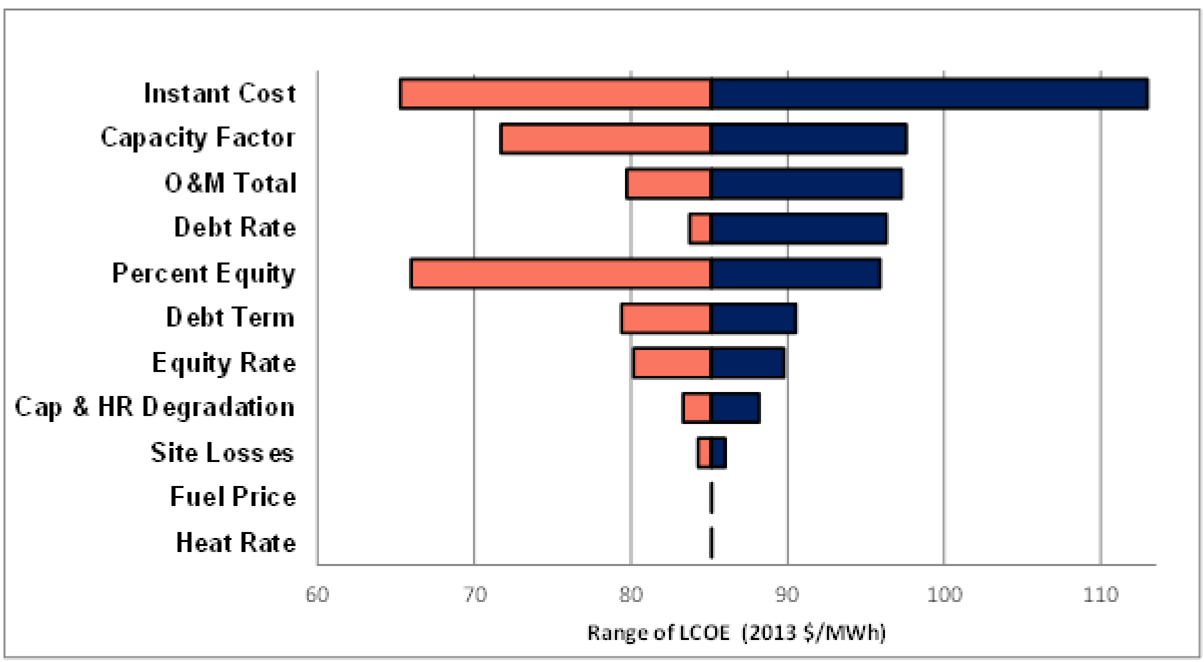
Source: Energy Commission.

Figure 56: Tornado Diagram—Solar Photovoltaic Single Axis 100 MW—Year = 2013



Source: Energy Commission.

Figure 57 Tornado Diagram—Wind—Class 3 100 MW—Year = 2013



Source: Energy Commission.

Range of Levelized Costs—Highs and Lows

The mid case LCOEs are the values most commonly quoted and used in cost studies, which are somewhat misleading, since these single-point cost estimates are not likely to be observed in any specific case. Actual costs and, therefore, LCOEs, vary across a range of possible values depending on multiple factors. Using point estimates can cause overconfident assessments that can result in poor decisions. All studies, including those of levelized costs, need to consider a likely range of costs and, thereby, consider a plausible range of outcomes. Decisions should reflect the range of possibilities.

In the *2009 IEPR*, staff provided a range of LCOEs for the first time, in recognition of the limitations of point forecasts. These high-low costs can be found as an output of the COG Model in juxtaposition to mid-cost cases. Although this was a step forward, it was a simplistic, deterministic technique for setting high-low ranges and is flawed in that the high and low LCOEs were based on the respective coincident high and low cost assumptions. The likelihood of all high-cost components occurring coincidentally or all the low-cost components occurring coincidentally is so unlikely as to be outside the range of consideration. The estimates shown in Figure 58 use the *2009 IEPR* method to estimate the range of levelized costs using the current data for the current set of technologies for the start year of 2013 (2013 nominal dollars)— at the point of interconnection.

Staff used a better approach for this report. Rather than select all high or all low factors simultaneously, this approach expresses uncertainty about each cost driver using probability distributions. Staff generated ranges of LCOE using the ACAT, a model developed using Lumina's Analytica software in conjunction with the Energy Commission's deterministic, spreadsheet-based COG Model (Sherwin and Henrion, 2013; Lumina, 2013). ACAT treats the low, mid, and high values for each input respectively as the 10th, 50th, and 90th percentiles of a fitted probability distribution. **Figure 59** shows the results of using the ACAT model to estimate probabilistic ranges of LCOE. ACAT allows the user to select the shape of the distributions. Cubic spline distributions were used in these results,[63] further described in Appendix D.

ACAT randomly samples from the distributions for the inputs for each selected technology. It passes each set of values to the COG Model spreadsheet and records the resulting LCOE. ACAT runs COG Model many times to perform Monte Carlo simulations to generate a random sample of LCOE values from which it estimates the resulting probability distributions.

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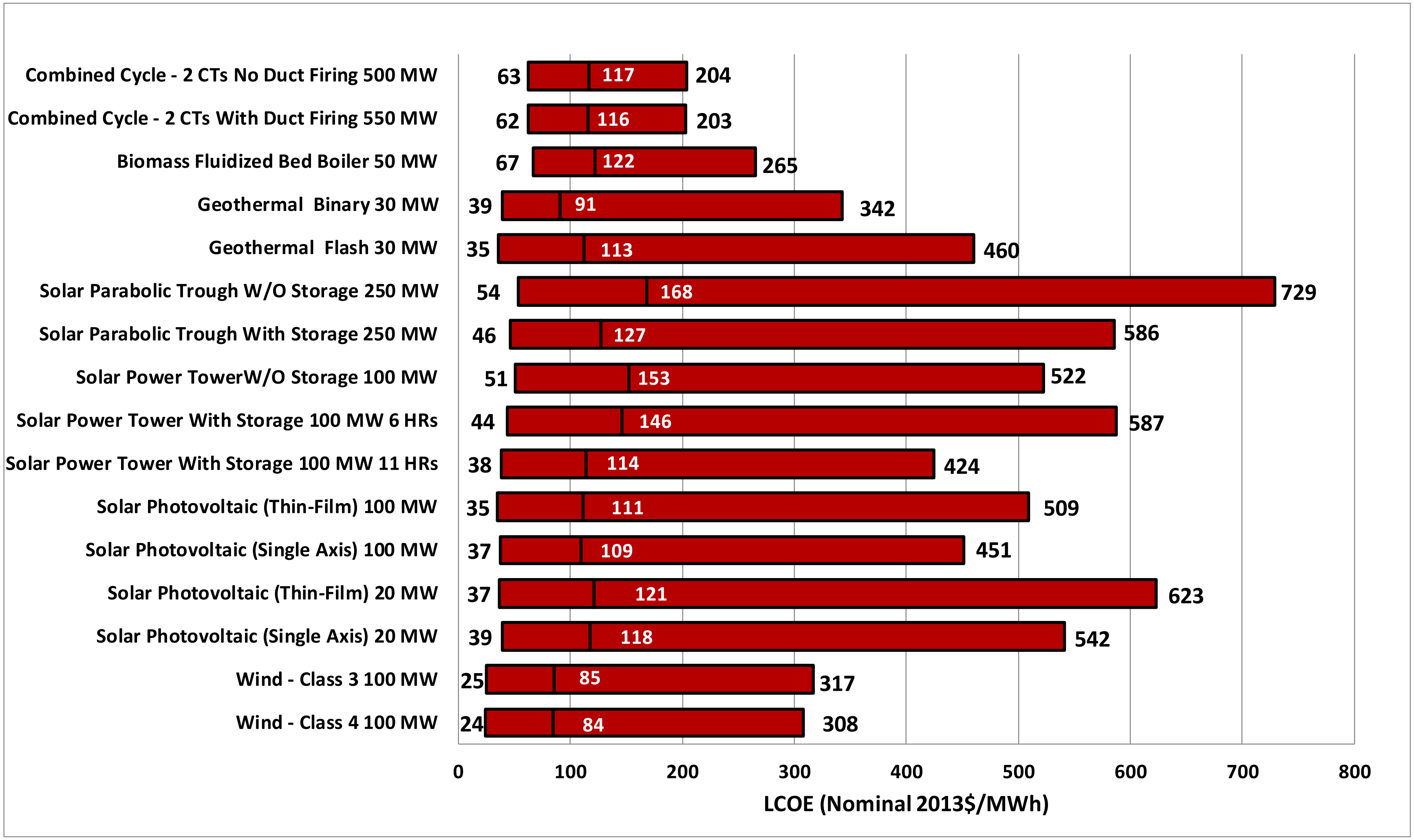
63 Although triangular distributions are commonly used as a proxy where the actual distribution is unknown, the cubic spline was used here as it assumes a more realistic smoothness—and in the Energy Commission's case gave much more believable mid-cost values. It is set to fit the estimated 10th, 50th, and 90th percentiles. It creates a bell-shaped density function with finite bounds on upper and lower tails (Spline, 2013).

Figure 60 compares the ACAT probabilistic levelized costs to the deterministic COG Model levelized costs for selected technologies, which illustrates the dramatic difference in range of costs. Whereas the deterministic low for the solar PV single-axis 100 MW technology is calculated as $37/MWh, realistically only $76/MWh can be achieved within the 10 percentile limit.

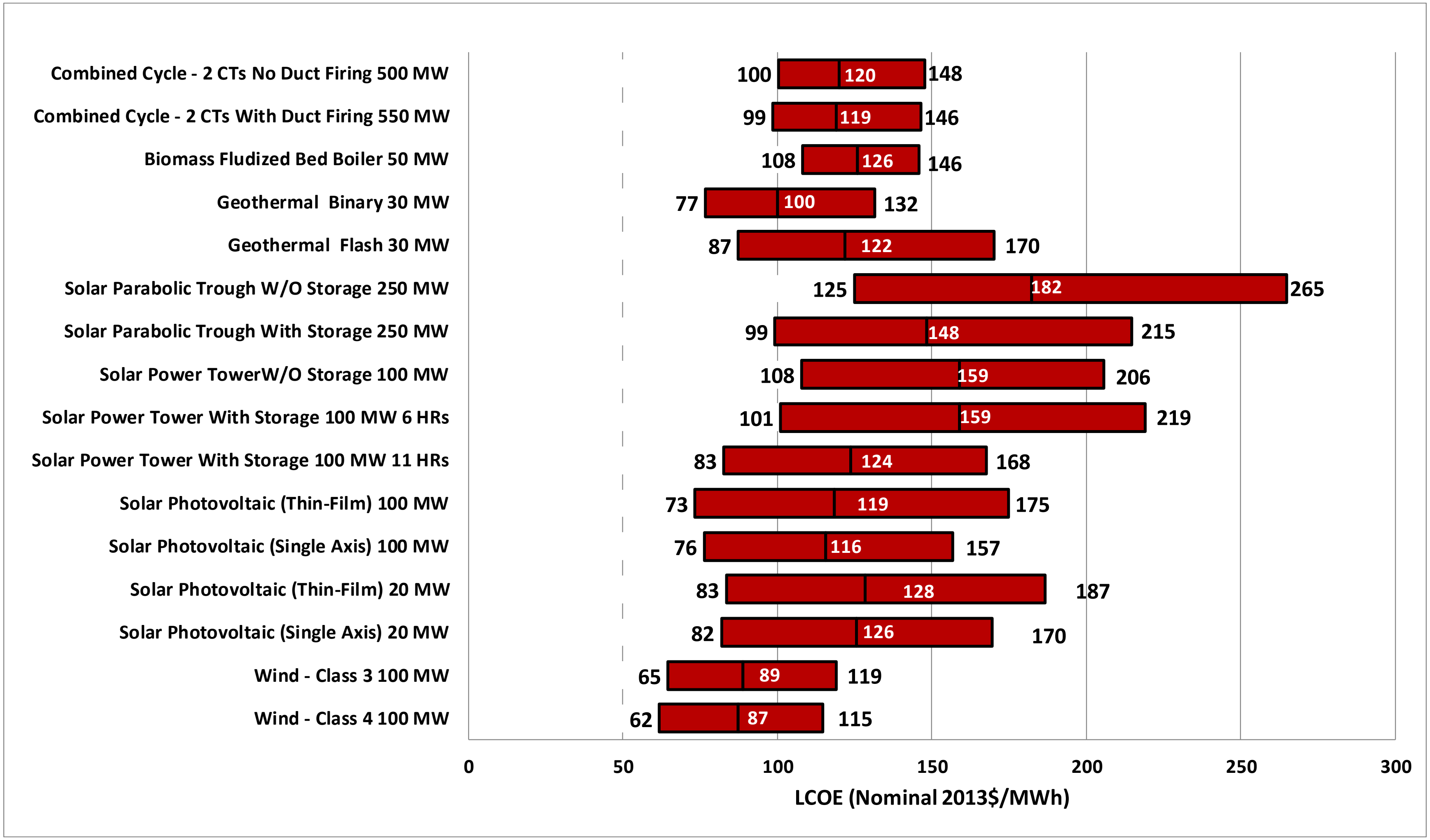
This, too, is merely a step forward. Although this proposed ACAT range of costs is much more reasonable than those proposed using the deterministic method, it is not perfect in that probabilistic assessment relies on assumed distributions of the cost and plant assumptions. In the majority of cases, there are insufficient data to rigorously develop distributions based on historical data; instead, the ranges must be set subjectively through professional judgment. In fact, developing objective probability distributions is impossible for several of these variables. In addition, there is always the uncertainty of any estimated assumption, which means it is never going to be perfect.

Figure 58: Deterministic Levelized Cost Range—Start Year=2013



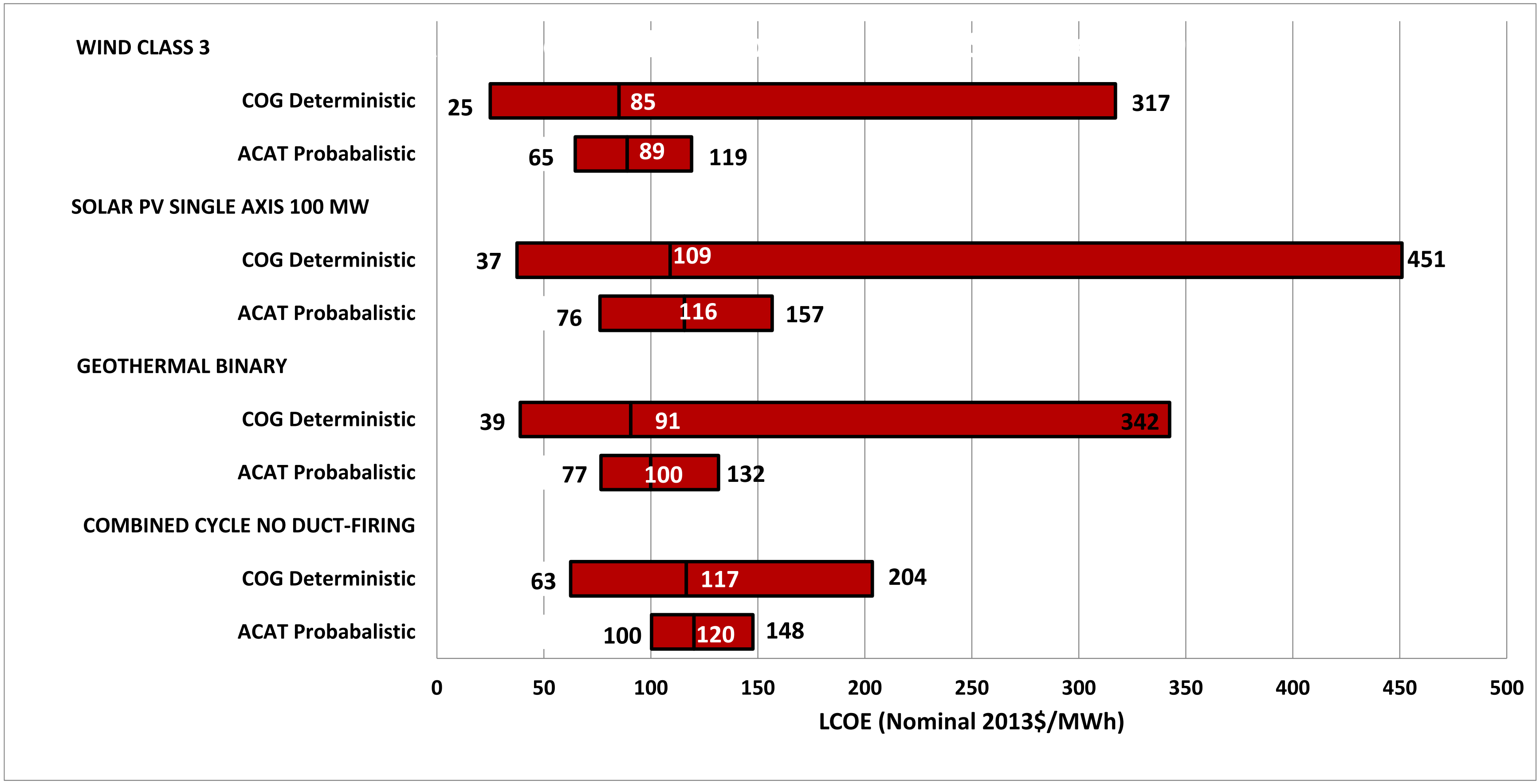
Source: Energy Commission.

Figure 59: Levelized Cost Range Using ACAT Probabilistic Method—Start Year=2013



Source: Energy Commission.

Figure 60: Comparing Levelized Cost of Energy Ranges—ACAT Probabilistic vs. Cost of Generation Deterministic



Source: Energy Commission.

Range of Levelized Costs—Busbar Costs

All of the previous LCOE values are reported at the point of interconnection with the existing transmission system. That is, the LCOE includes the cost of interconnection transmission and related losses.

However, many studies report LCOE at the plant busbar level and do not include transmission costs, which in some cases produce a significantly lower LCOE. For this reason, staff is also reporting LCOE probabilistic data at the busbar to show the effect of the interconnection costs. **Table 65** shows the effect with and without transmission on LCOE.

Table 65: Effect of Interconnection Transmission on LCOE

In-Service Year = 2013	Size	LCOE ($/MWh)			As a
	MW	With	Without	Difference	Percent
Generation Turbine 49.9 MW	49.9	663.80	594.85	68.95	10%
Generation Turbine 100 MW	100	661.51	619.81	41.71	6%
Generation Turbine - Advanced 200 MW	200	404.10	361.51	42.59	11%
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	116.57	114.15	2.43	2%
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	115.88	113.63	2.25	2%
Biomass Fludized Bed Boiler 50 MW	50	122.07	119.59	2.48	2%
Geothermal Binary 30 MW	30	90.63	86.00	4.63	5%
Geothermal Flash 30 MW	30	112.51	107.54	4.96	4%
Solar Parabolic Trough W/O Storage 250 MW	250	168.18	163.65	4.53	3%
Solar Parabolic Trough With Storage 250 MW	250	127.40	124.77	2.63	2%
Solar Power Tower W/O Storage 100 MW	100	152.58	148.51	4.07	3%
Solar Power Tower With Storage 100 MW 6 HRs	100	145.52	142.28	3.24	2%
Solar Power Tower With Storage 100 MW 11 HRs	100	114.06	111.64	2.42	2%
Solar Photovoltaic (Thin-Film) 100 MW	100	111.07	107.29	3.78	3%
Solar Photovoltaic (Single Axis) 100 MW	100	109.00	105.66	3.35	3%
Solar Photovoltaic (Thin-Film) 20 MW	20	121.31	107.29	14.02	12%
Solar Photovoltaic (Single Axis) 20 MW	20	117.74	105.66	12.09	10%
Wind - Class 3 100 MW	100	85.12	79.53	5.59	7%
Wind - Class 4 100 MW	100	84.31	78.53	5.77	7%

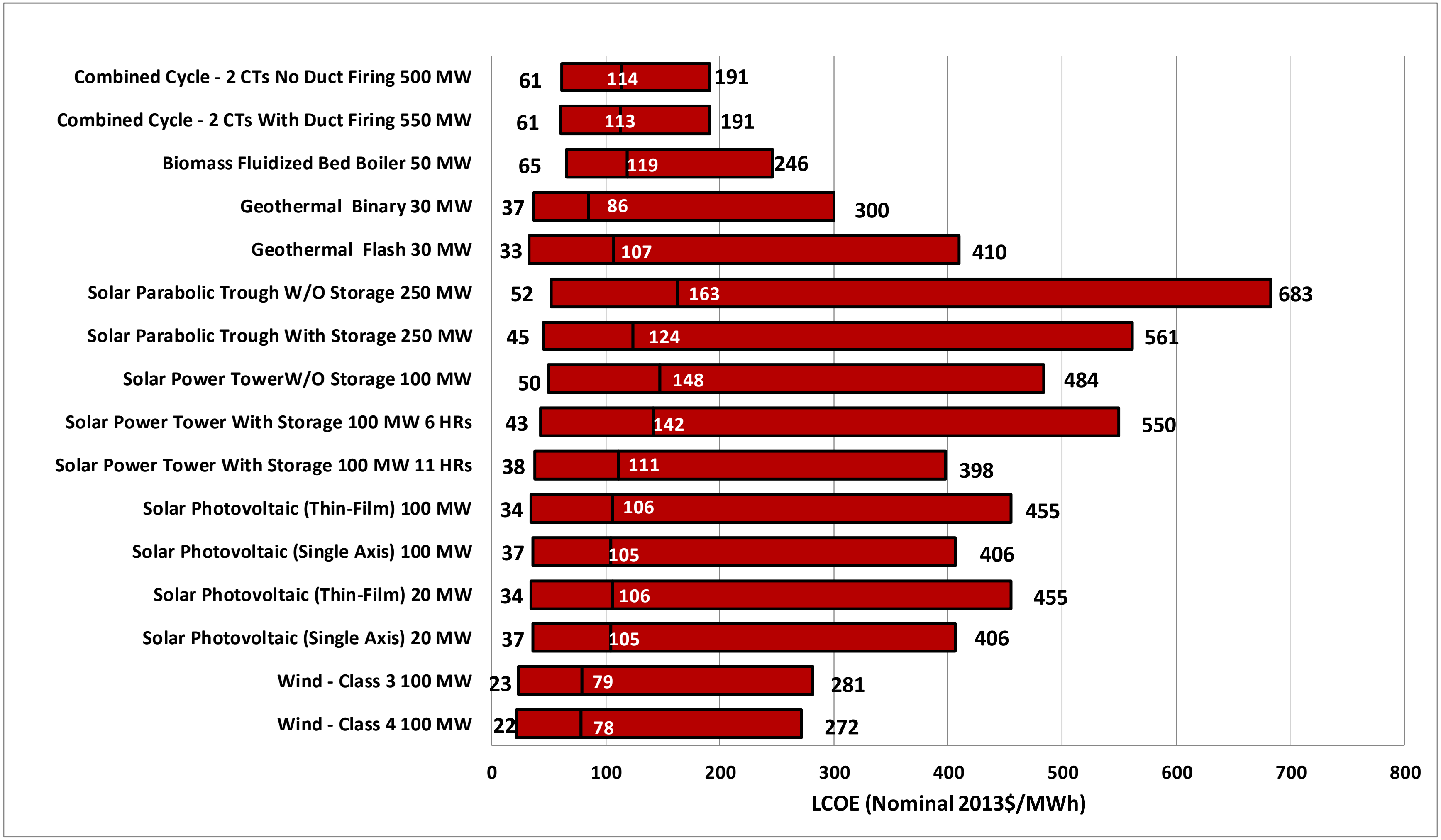
Source: Energy Commission.

Figure 61 summarizes the deterministic LCOEs at the plant busbar level. **Figure 62** summarizes the corresponding probabilistic LCOEs generated by ACAT at the busbar level.

Figure 63 compares the busbar levelized costs to the previous interconnection point LCOEs for selected technologies. Transmission can have a significant effect on the probabilistic highs and lows.

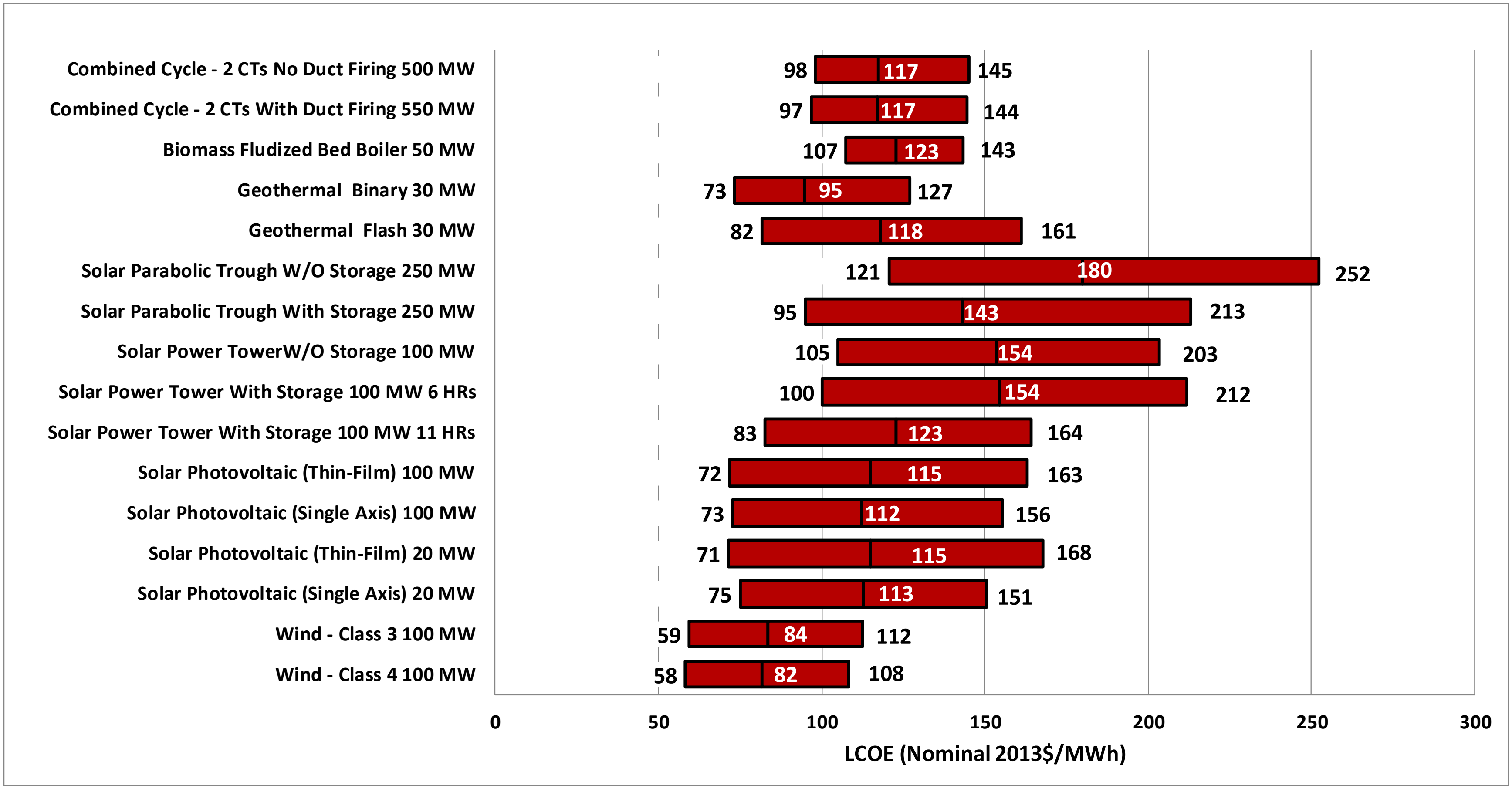
This also points out that levelized costs need to be well documented if they are to be of any real value. This is not a standard that is always adhered to in the various LCOE studies and the supporting assumptions reported in the literature.

Figure 61: Deterministic Levelized Cost Range—Busbar—Start Year=2013



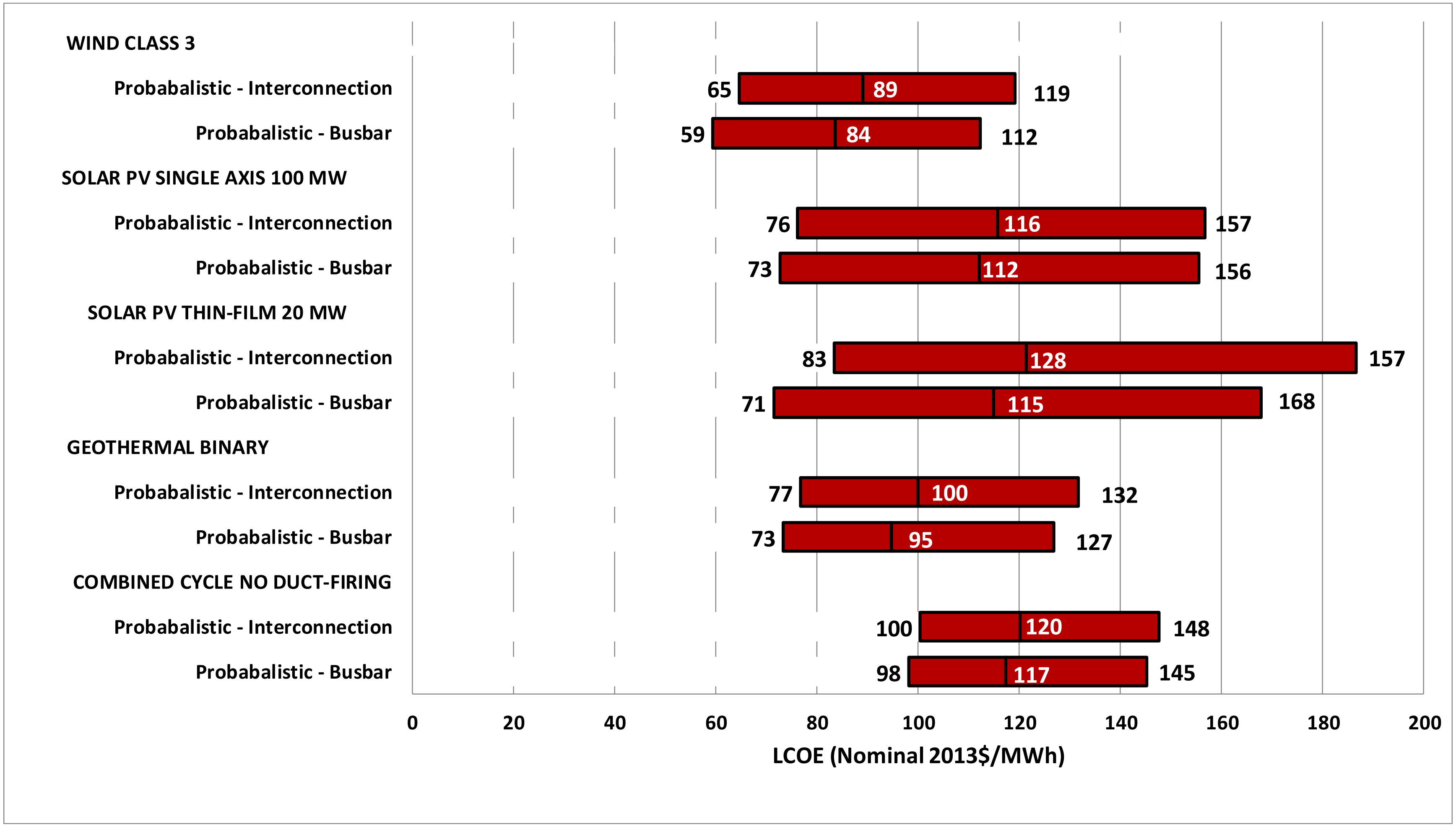
Source: Energy Commission.

Figure 62: Levelized Cost Range Using ACAT Probabilistic Method—Busbar—Start Year=2013



Source: Energy Commission.

Figure 63: Comparison of Busbar to Interconnection Point Levelized Cost of Energy—Start Year=2013



Source: Energy Commission.

Levelized Cost of Net Qualifying Capacity

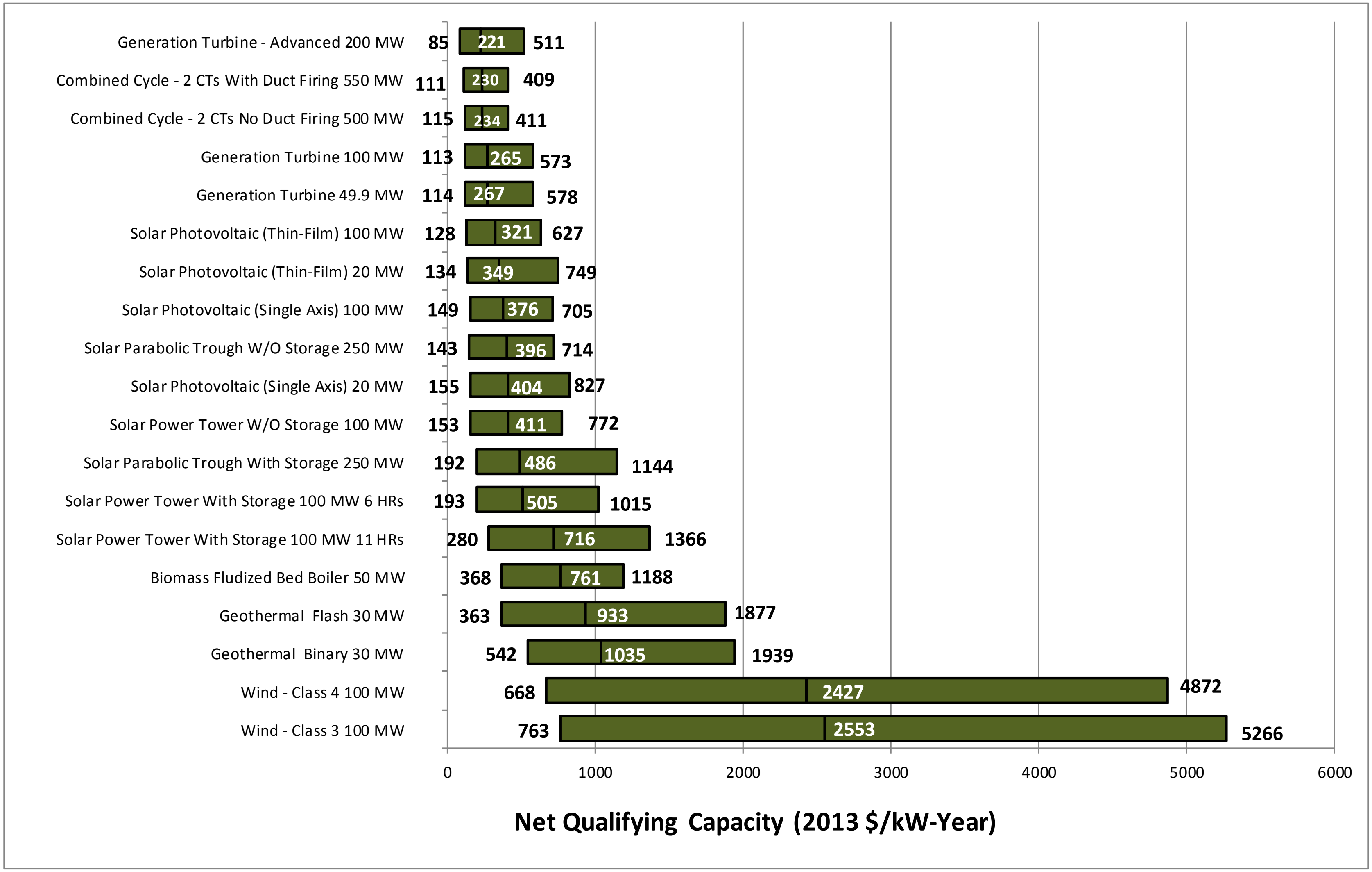
As mentioned earlier in the chapter, LCOE is only one factor taken into consideration by utilities and regulators in deciding what types and locations of new generation resources should be built. In fact, it is not the only cost factor. The LCOE values in **Figure 64** are based on the cost per unit of energy produced. This tends to make resources with high energy production look attractive. However, the electricity system in California needs more than energy. The capacity of a generation resource must be considered when electricity system planners attempt to address growth in peak demand. Peak demand is the maximum amount of demand served by the electric grid during an hour of the day.

The capacity value of resources is a key metric in ensuring that the electric system has sufficient resources during those peak hours of the day. The CPUC, working in consultation with the California ISO and the Energy Commission, establishes resource adequacy (RA) under Rulemaking R.08-10-025. As a part of this effort, the CPUC determines the net qualifying capacity (NQC) for California resources serving the California ISO control area. *NQC* is the amount of capacity for each generation plant that can be relied upon during the typical peak demand hour. This means that resources that are typically generating near full power during 4:00 p.m. to 6:00 p.m. in the summer have a higher percentage of the full capacity designated as NQC.

To illustrate the limitations of using energy as the sole metric when conducting resource planning, **Figure 64** presents estimates of cost /kW-yr. of NQC for the different technologies based on the fixed cost portion of LCOE sorted by mid case values lowest to highest.

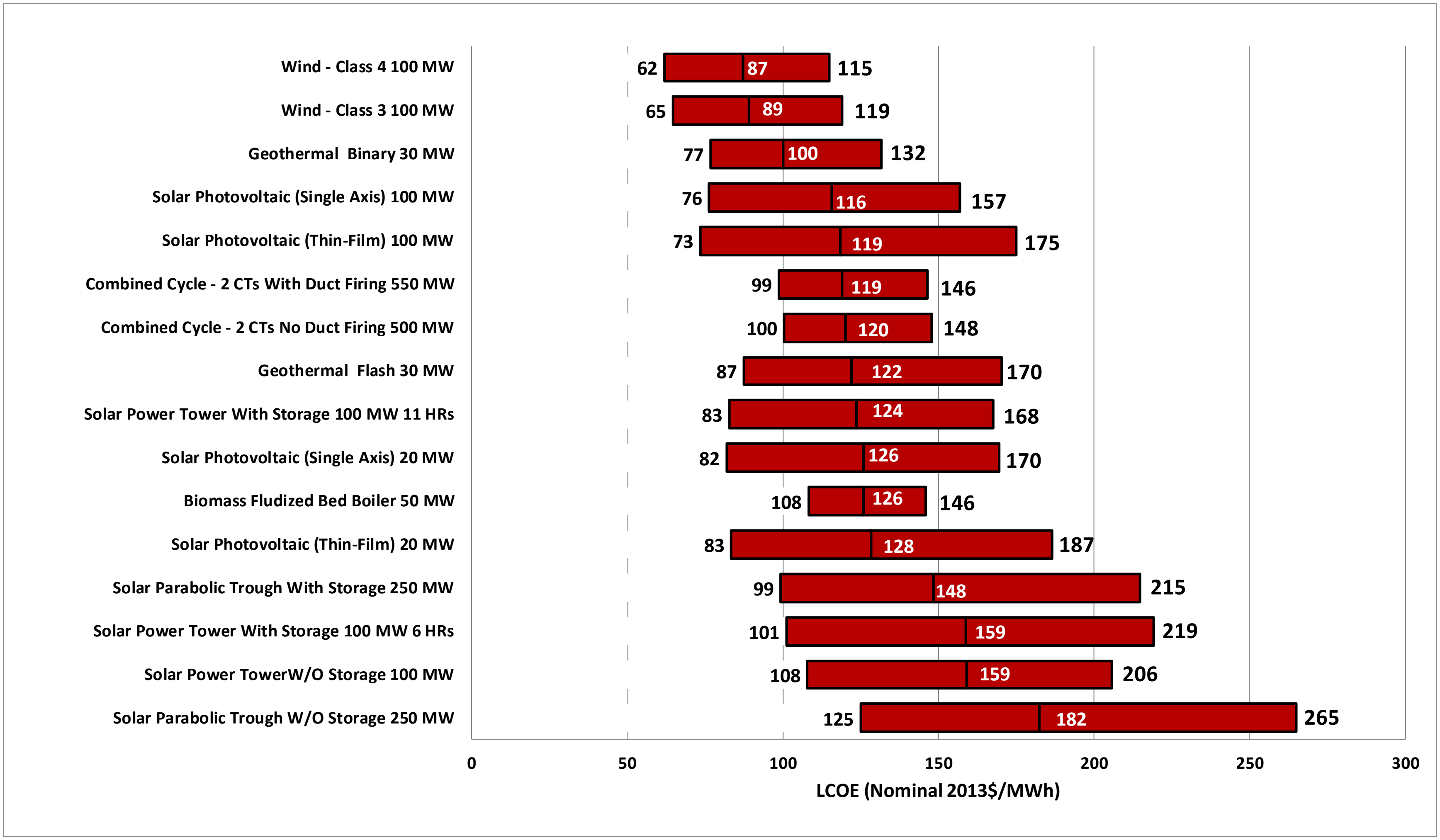
Figure 64 as compared to **Figure 65** shows the differences in relative cost ranking of technologies when the perspective is changed from cost per unit capacity to cost per unit energy. Wind technologies move from being the highest cost per unit of capacity to the lowest estimated levelized cost per unit of energy.

Figure 64: Merchant Levelized Cost of Net Qualifying Capacity—Sorted by Mid Case



Source: Energy Commission.

Figure 65: Merchant Levelized Cost of Energy Ranked by Mid Case Probabilistic



Source: Energy Commission.

CHAPTER 11: Conclusion and Next Steps

The primary goal of this project is to produce clear, understandable estimates of the costs associated with building and operating new power plants in California over the next decade. Any attempt to do so faces several challenges and limitations since the marketplace for new generation resources is rapidly evolving through the improvement of renewable technologies and changing relationships between the consumer and energy producer. For example, consumers who have traditionally relied exclusively on the utility for their electricity needs are now installing small on-site generation resources behind the meter. This is dramatically changing the overall electricity consumption patterns seen by the utility and, as a result, changing the operational characteristics that may be of value to the utility or grid operators in the foreseeable future.

Throughout this work, several key insights that may be of interest to stakeholders and policy makers presented themselves. In addition, the limitations of the project were often highlighted as stakeholders raised excellent questions and issues that unfortunately fell outside the bounds of time and resources allocated to this project. This section summarizes both the key insights as well as the areas for further investigation highlighted throughout the process. Stakeholders are invited to weigh in through written comments to this draft report and share their thoughts on how the content might be improved, as well as what new work should be explored next in understanding the cost trends of new generation.

Additional Key Insights

The insights derived from this work are as follows:

- The decline of technology costs associated with all solar technologies is expected to continue as manufacturers refine production processes and find low-cost solutions to problems.
- Wind Class 3 and 100 MW solar PV (single axis) technologies with incentives are already cost-competitive with 500 MW CC without duct firing at the developer level.
- While developer costs appear near parity of wind and solar technologies versus fossil, this study does not include the additional cost to the utility to support the integration of intermittent resources.
- The success and continued declining costs of nonPV solar technologies will depend upon the outcome of external issues and mitigation costs of those technologies.
- Wind technology is trending to increase CF by optimizing to lower wind speeds at the expense of lower peak generation capacity. It is unclear what impact this has on nameplate capacity compared to operational peak capacity.

- Increased quantities of biomass raises questions about long term procurement of fuel streams. This situation may increase the price of fuel for certain types of biomass generators, while those with secure fuel streams, like wastewater treatment plants and dairy farms, may not see a price increase.
- Long term expectations of low natural gas prices are likely to make gas-fired power technologies, such as CTs and CCs, attractive to investors in the near term. This same trend may challenge the ability of renewable technologies to compete on a cost basis with fossil technologies.
- Despite their higher levelized costs, CT power plants, based on aeroderivative designs, are being built almost exclusively in California instead of CC power plants. Presumably this is due to their operational profiles being better suited to compensate for the variable generation profiles of renewable resources.
- The cost of GHG emissions credits will likely be a major cost factor in future development of natural gas-fired resources.

Areas for Further Investigation

The project scope was ambitious. However, the areas of interest to stakeholders and policy makers are far larger than could be encompassed in this report. The following areas related to the cost of new generation in California were identified as being important and/or interesting to investigate in the future:

- How should the cost of storage technologies be calculated given the reliance on external generation sources for power?
- How might storage be most cost-effectively bundled with renewable generation to serve load in California?
- Traditional CC or CT technologies used in combined heat and power applications introduce additional complexity, including heat recovery equipment, specialized equipment that is location- and industry-dependent, and multiple forms of energy output. How do these additional factors influence the cost of technologies used in combined heat and power applications?
- Many areas of California are constrained with regard to the suitable land available to host a gas-fired power plant. What is the levelized cost of a repower project for a CC or CT on an existing site (or “brownfield”) compared to the same development on a new (or “greenfield”) site?
- As the renewable resource fleet in California ages, some of it will have to be upgraded or replaced. How might the replacement of aging renewable resources with newer technologies affect the expected costs of those projects?
- The developer of a new power plant is not strictly reliant on a single contract to provide the stream of income necessary to recover costs. Markets such as those for ancillary services and resource adequacy can provide additional streams, changing the amount a

developer might be willing to accept for a project. A study laying out these options and how they might affect the market for contracts could be of value to policy makers. Renewable resources can present challenges to utilities that must meet demand regardless of the availability of any response. An estimate of the cost of integration from the utility perspective was proposed by several stakeholders.

- Differences exist in the reported CFs between CTs owned and operated by POUs, IOUs, and merchant operators. These differences result in significant cost implications among the three classes. The reason for the empirical difference is not clear and bears further investigation.

Stakeholders' input is essential in developing, refining, and vetting this report. The authors would like to thank all stakeholders for their comments and participation. Stakeholders are encouraged to stay involved in the future.

ACRONYMS

ACRONYM	DEFINITION
$/kWh	Dollars per kilowatt hour
$/kW-yr.	Dollars per kilowatt year
$/MWh	Dollars per megawatt hour
$/MWh	Dollars per megawatt hour
/kW-year	Per kilowatt year
˚C	Celsius
˚F	Fahrenheit
AB 32	Assembly Bill 32
AC	Alternating current
ACAT	Analytica Cost of Generation Analysis Tool
AFUDC	Allowance for funds used during construction
APCD	San Joaquin Unified Air Pollution District
ARB	California Air Resources Board
ARRA	American Recovery and Reinvestment Act
BAA	Balancing authority area
BETC	Business Energy Tax Credits
BFB	Bubbling fluidized bed
BLM	Bureau of Land Management
BOE	Board of Equalization
BOS	Balance of system
Btu/kWh	British thermal units per kilowatt hour
Btu/scf	British thermal units per standard cubic foot
California Energy Commission	Energy Commission
California ISO	California Independent System Operator
CC	Combined cycle
CCTP	California Cap and Trade Program
CF	Capacity factor
CFB	Circulating fluidized bed
CO_{2e}	Carbon dioxide equivalent
COG	Cost of Generation
COG Model	Cost of Generation Model
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CREST	Cost of Renewable Spreadsheet Tool
CSP	Concentrated solar power
CT	Combustion turbine
DC	Direct current
DG	Distributed generation
DSCR	Debt service recovery ratios
DSM	Demand-side management
EERE	Energy efficiency and renewable energy
EFOR	Equivalent forced outage rates
EFORd	Equivalent forced outage rates demand
EMAC	Emission Market Assessment Committee
EPAct	Federal Energy Policy Acts

ACRONYM	DEFINITION
EPIA	European Photovoltaic Industry Association
EPRI	Electric Power Research Institute
ERC	Emission Reduction Credit
FERC	Federal Energy Regulatory Commission
FOR	Forced outage rates
GADS	Generating Availability Data System
GETEM	Geothermal Electricity Technology Evaluation Model
GHG	Greenhouse gas
HHV	Higher heating value
HRSG	Heat recovery steam generator
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
IPP	Independent power producer
ITC	Investment Tax Credit
kW	Kilowatt
LADWP	Los Angeles Department of Water & Power
LBNL	Lawrence Berkeley National Laboratory
Lbs/MMBtu	Pounds per million British thermal units
Lbs/MWh	Pounds per megawatt hour
LCOE	Levelized cost of energy
LIBOR	London Interbank Overnight Rate
LTPP	Long-Term Procurement Proceeding
MRW	MRW Consulting
MSG	Market Simulation Group
MW	Megawatt
MWh	Megawatt hour
NAMGas	North American Gas-Trade Model
NCF	Net capacity factor
NO_x	Oxides of nitrogen
NQC	Net qualifying capacity
NREL	National Renewable Energy Laboratory
NSPS	New source performance standards
NSR	New Source Review
O&M	Operations and maintenance
ODC	Other direct costs
PIER	Public Interest Energy Research
PM	Particulate matter
PPA	Power purchase agreement
PTC	Production tax credit
PURPA	Public Utility Regulatory Policy Act
PV	Photovoltaic
QFER	*Quarterly Fuels and Energy Report*
RA	Resource adequacy
RAM	Renewable Auction Mechanism
RECLAIM	Regional Clean Air Incentives Market
REPI	Renewable Energy Production Incentives
REPTC	Renewable Energy Production Tax Credits

ACRONYM	DEFINITION
ROG	Reactive organic gases
RPS	Renewables Portfolio Standard
RTC	RECLAIM Trading Credits
SC	Simple cycle
SCE	Southern California Edison
SCQAMD	South Coast Air Management District
SEGS	Solar energy generating systems
SOF	Scheduled outage factor
SONGS	San Onofre Nuclear Generating Station
SO_X	Oxides of sulfur
TDMA	Tax deduction for manufacturing activities
TES	Thermal energy storage
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Administration
VOC	Volatile organic compound
WACC	Weighted average cost of capital
WECC	Western Electricity Coordinating Council

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APPENDIX A:
Effect of Tax Benefits

This attachment quantifies the effect of the tax benefits described in Chapters 2 and 10 on LCOE. All values are for merchant developers and the mid case. These LCOEs are all point of interconnection with the existing system, not busbar costs.

Figure A-1 shows the merchant mid case LCOEs as reported throughout this report. These are the LCOE costs as borne by the developer, and are for technologies going online in 2013 presented in nominal 2013 $/MWh.

Figure A-2 shows the merchant mid case LCOEs with the tax benefits included. The tax deduction for manufacturing activities (TDMA) is not shown as a separate entity because it too small in magnitude to be visible on the graph.

Figure A-3 shows the same data as **Figure A-2**, except that tax benefits have been collapsed into two categories:

- Tax Deductions: Accelerated depreciation, solar exemption from ad valorem, and TDMA
- Tax Credits: Business Energy Investment Tax Credit (ITC) and Renewable Energy Production Tax Credit (PTC).

Figure A-4 shows the same data as **Figure A-3** except that the gas-fired technologies have been removed to expand the figure and better identify the magnitudes of the renewable technologies.

Figure A-5 is the same as **Figure A-4** except that all the tax benefits have been collapsed into one value.

Figure A-6 is the comparable data to **Figure A-5** for 2024.

Figure A-7 is comparable to **Figure A-5** except that the gas-fired technologies have been included and the graph is sorted by total cost.

Although these are interesting and useful snapshots in time, the LCOEs also need to be looked at in the longer time perspective. The remaining figures show the effect of tax benefits through the 2013 – 2024 time horizon. **Figure A-8** shows tax benefits for solar PV thin-film 100 MW technology, the lowest cost LCOE solar technology, and compares it to the 500 MW CC technology[64] as a reference point; it shows the solar technology with its

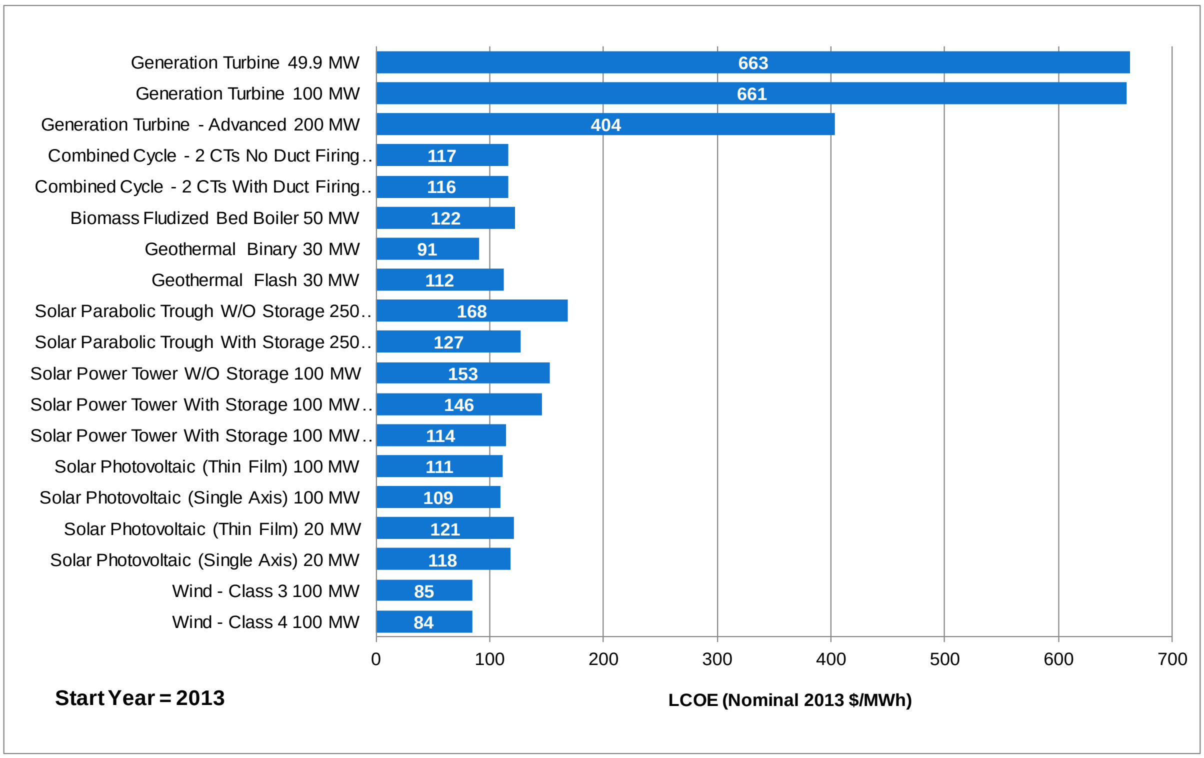
64 The CC unit has only the miniscule TDMA tax benefit and would not be visible as a variation on this graph.

present tax benefits[65] and then what it would be without any tax benefits whatsoever. Over the years, it becomes increasingly competitive until the end of the study period, when it passes the CC.

Figure A-9 shows the 20 MW solar PV thin-film technology. It shows similar characteristics to the 100 MW solar PV thin-film technology.

Figure A-10 – Figure A-14 show similar data for other technologies. The Wind 3 technology has a lower LCOE than the 500 MW combined cycle unit by 2017.

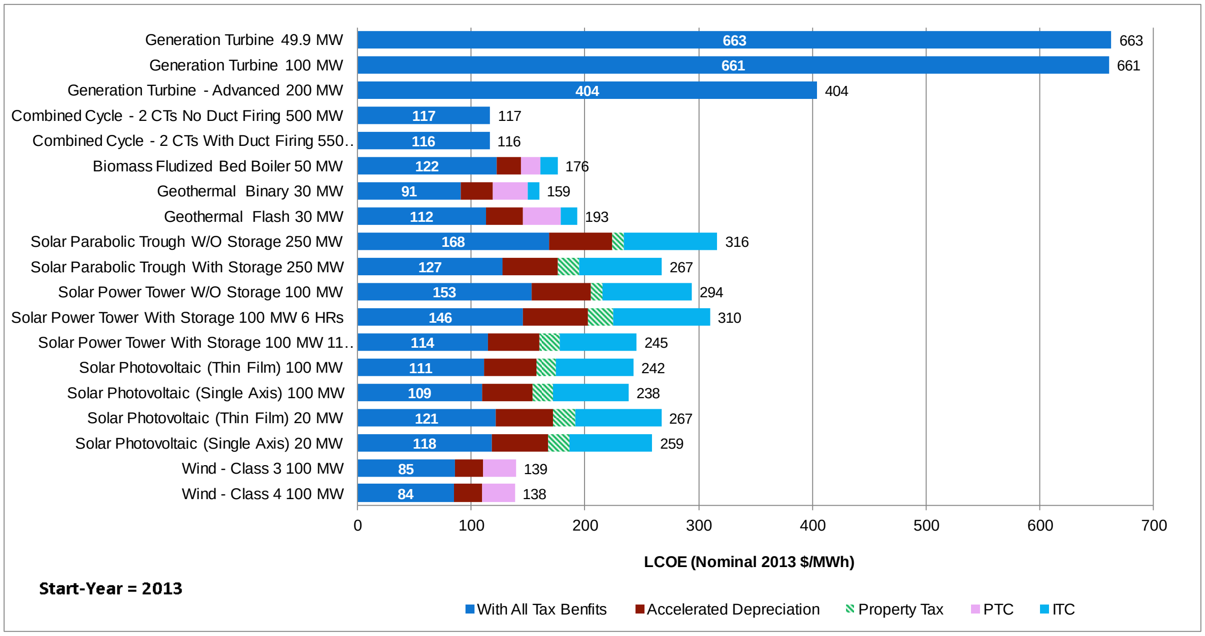
Figure A-1: Merchant Levelized Cost of Energy Values



Source: Energy Commission.

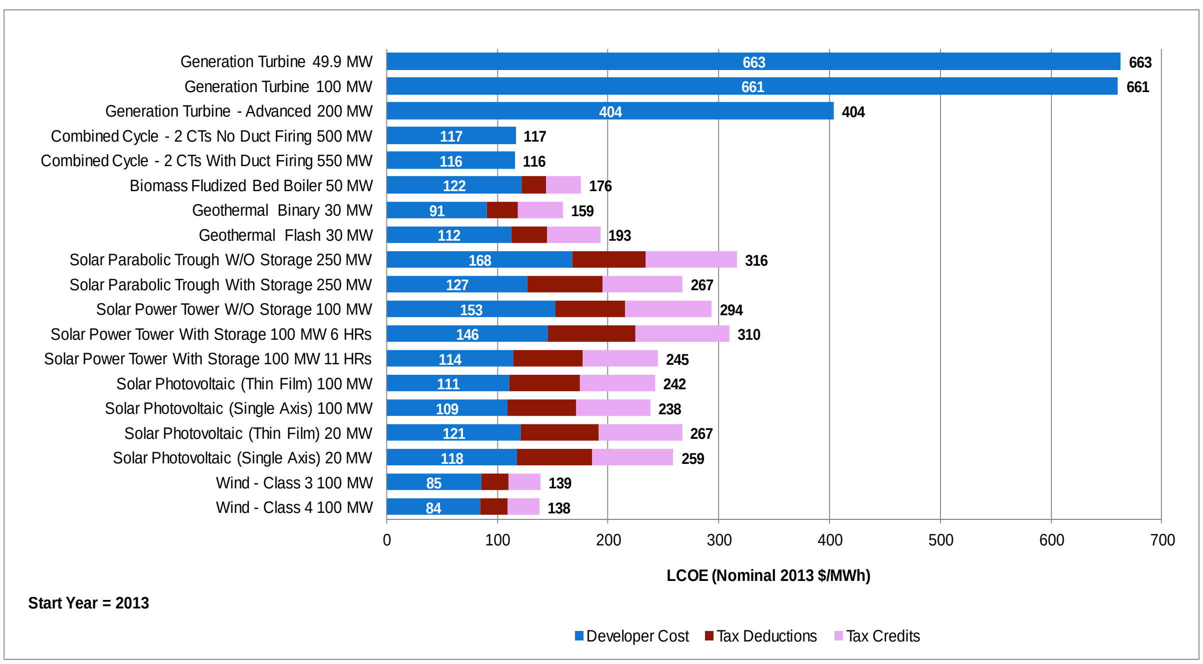
65 In 2017 the ad valorem tax exemption expires, and in 2018 the ITC tax credit expires; only accelerated depreciation and the miniscule TDMA continue.

Figure A-2: Merchant Levelized Cost of Energy Showing Both Developer Costs and Tax Benefits



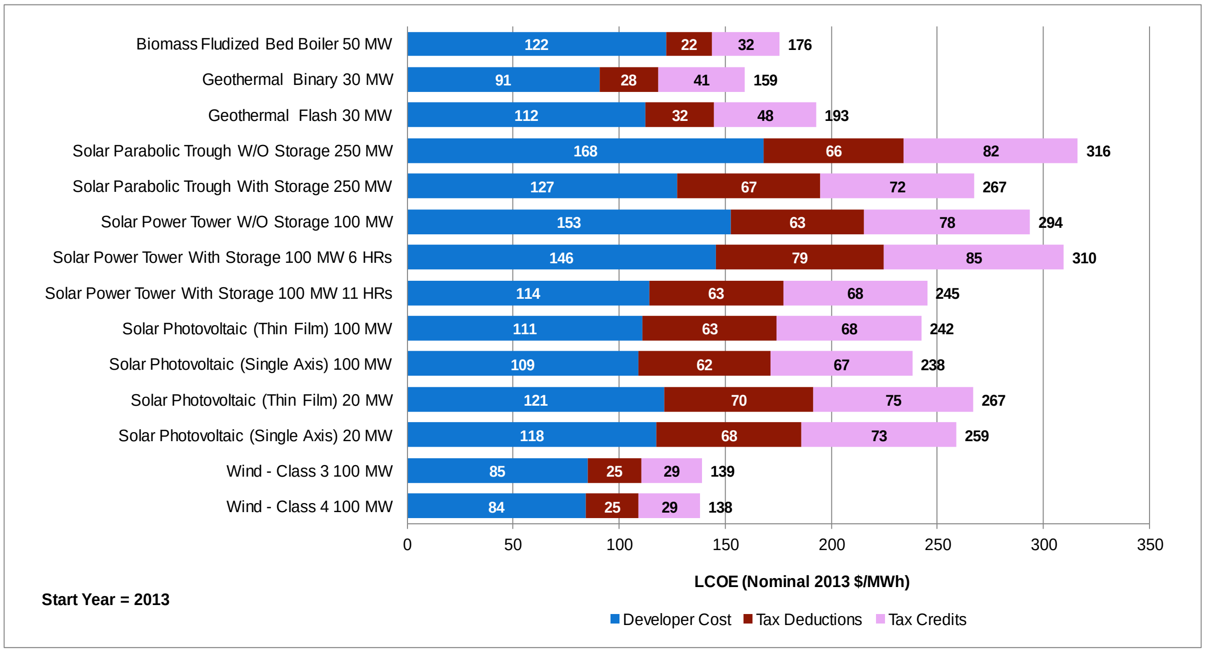
Source: Energy Commission.

Figure A-3: Merchant Tax Benefits Grouped Into the Two Main Categories: Tax Deductions and Tax Credits



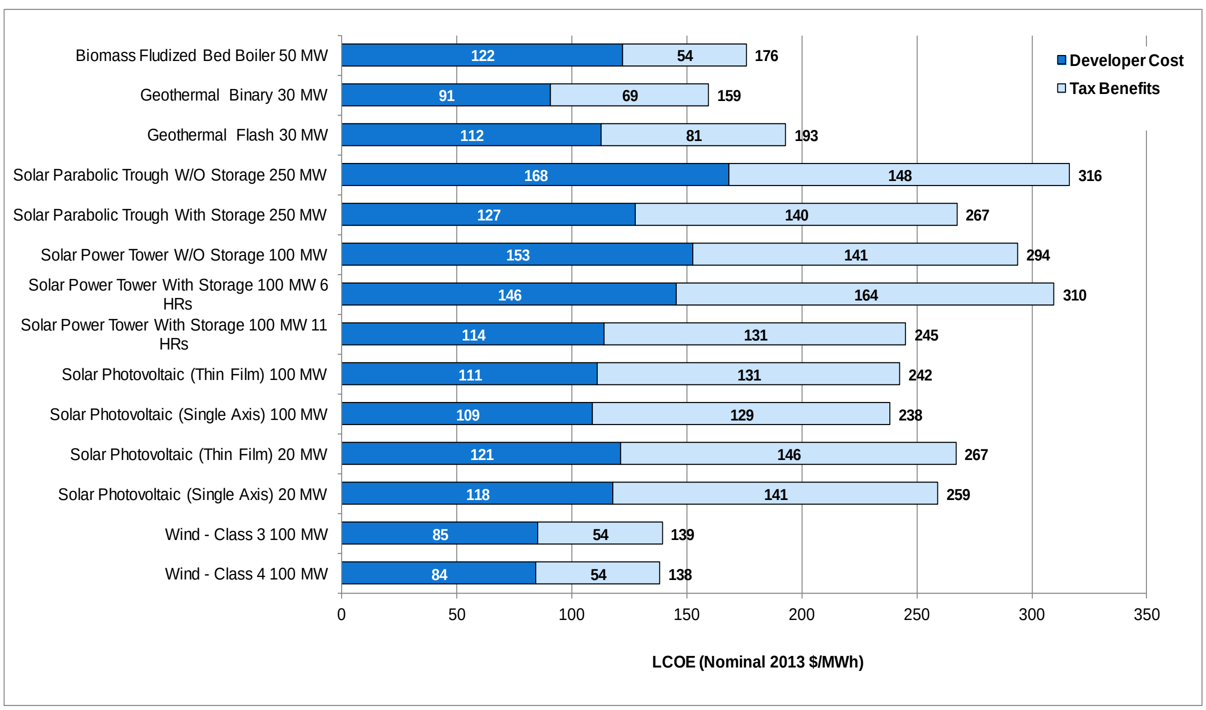
Source: Energy Commission.

Figure A-4: Same as Figure A-3 With Gas-Fired Units Removed



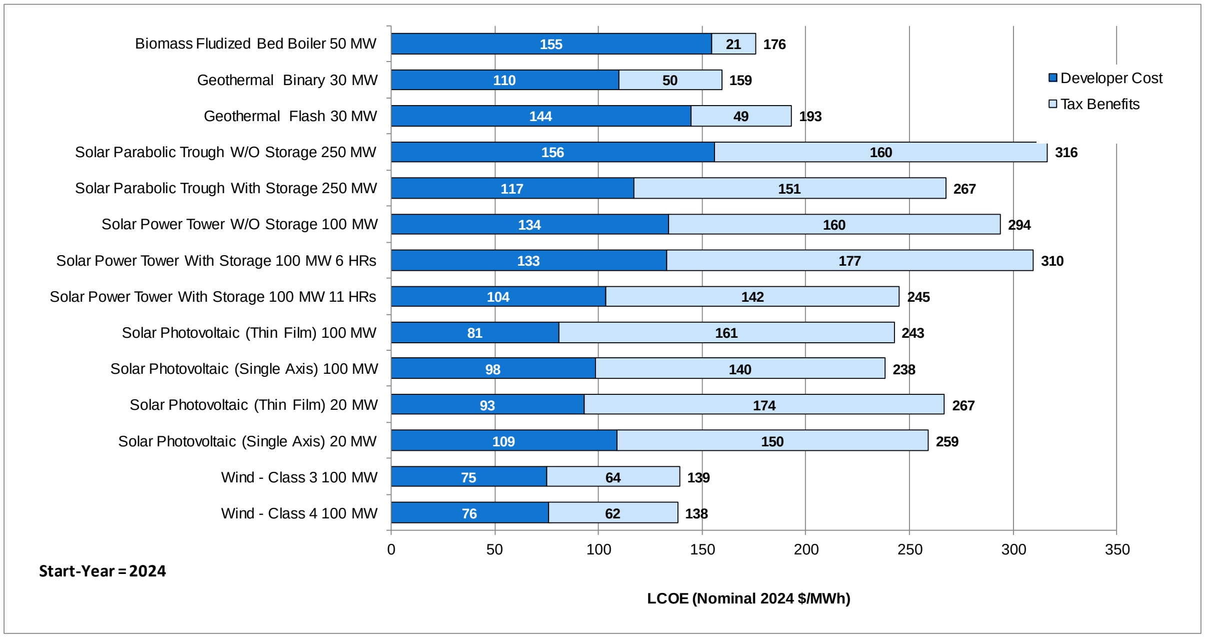
Source: Energy Commission.

Figure A-5: Developer Costs With Tax Benefit Costs Combined as One Value



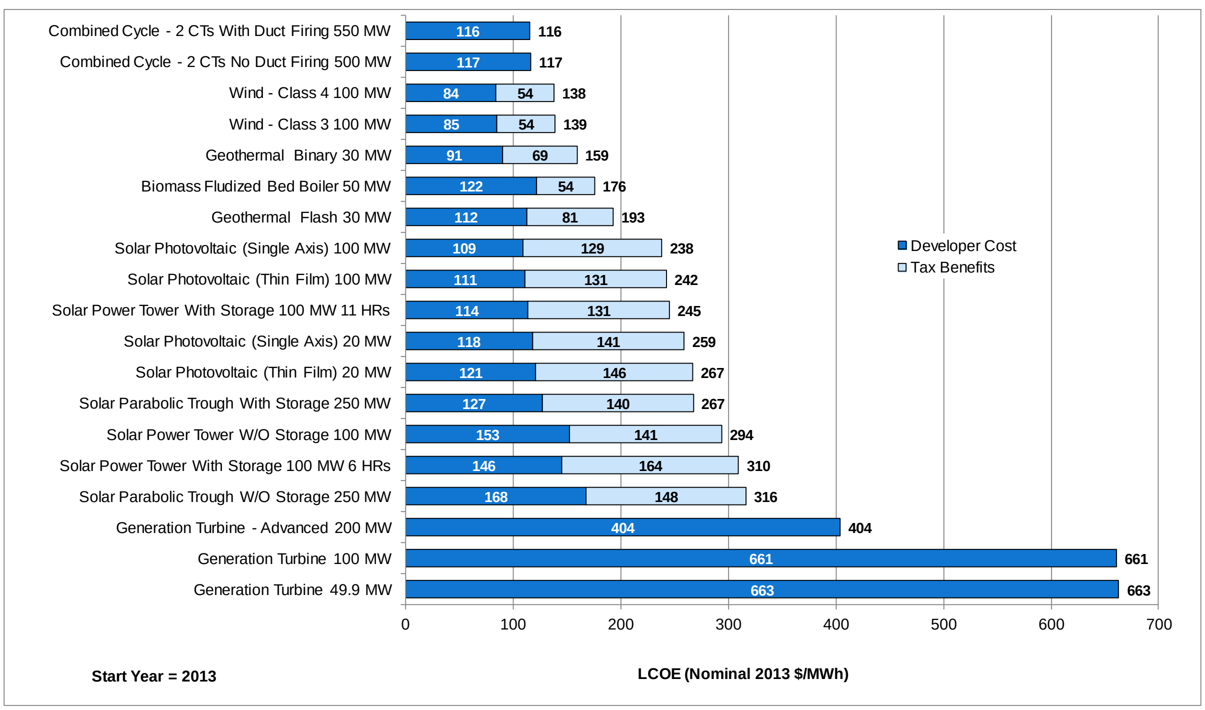
Source: Energy Commission.

Figure A-6: Merchant Developer Costs and Tax Benefit Costs Combined as One Value Start Year=2024



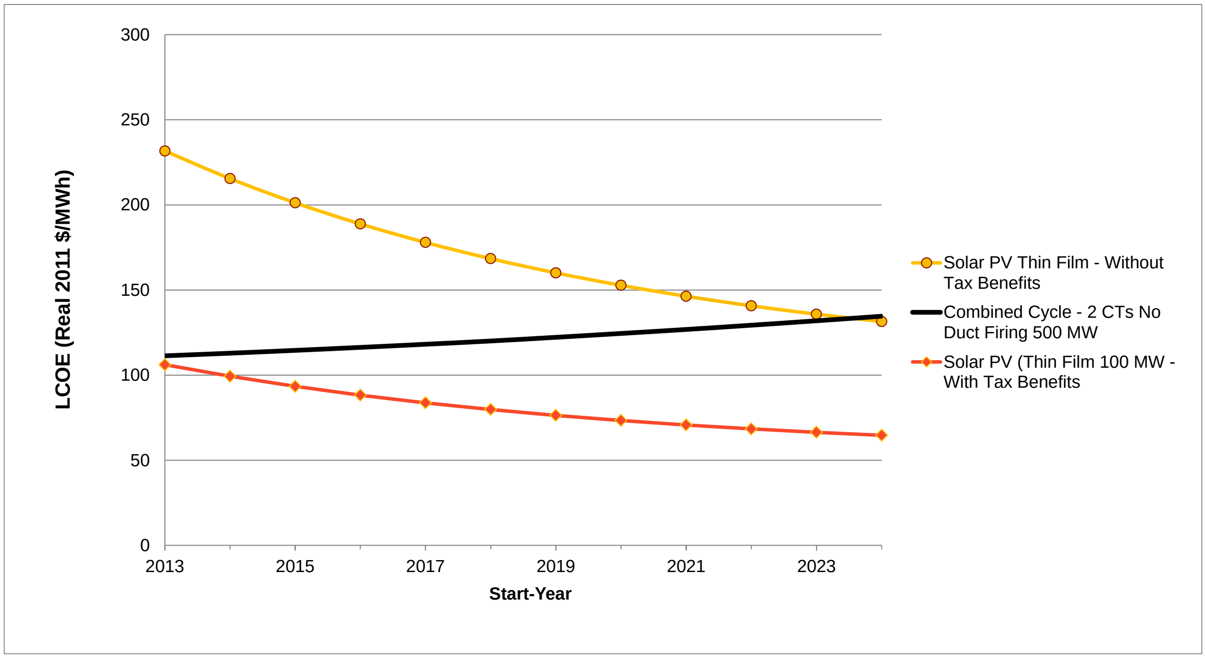
Source: Energy Commission.

Figure A-7: Sorting Costs Based on Total Cost



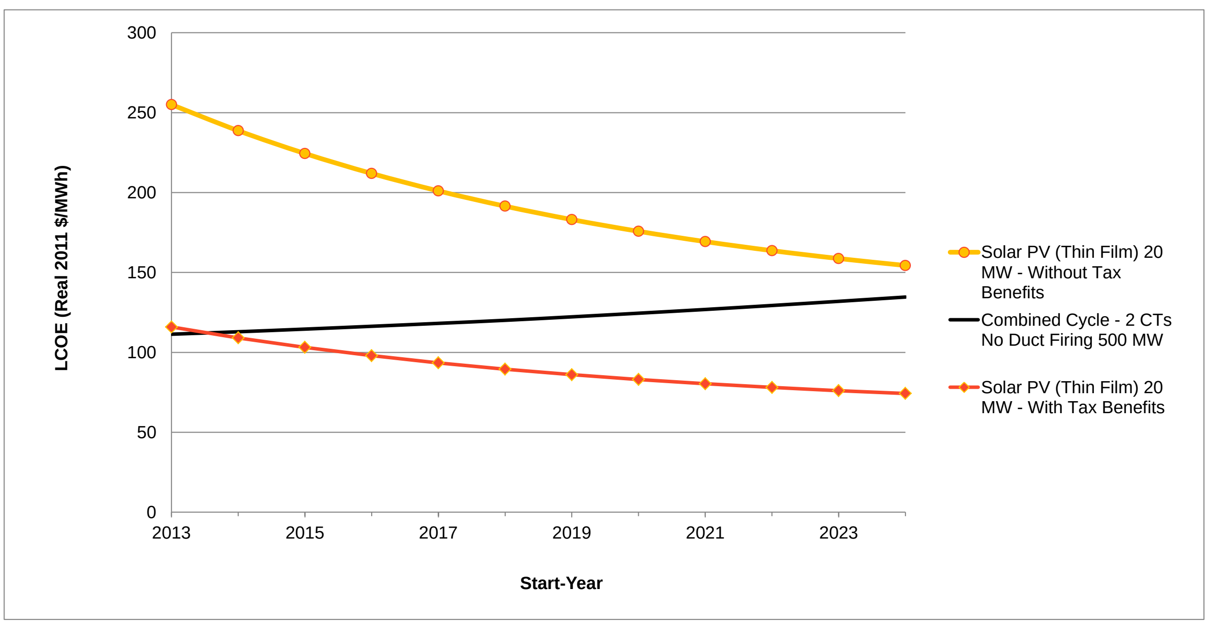
Source: Energy Commission.

Figure A-8: Effect of Tax Benefits on Solar Photovoltaic Thin-Film 100 MW vs. Combined Cycle



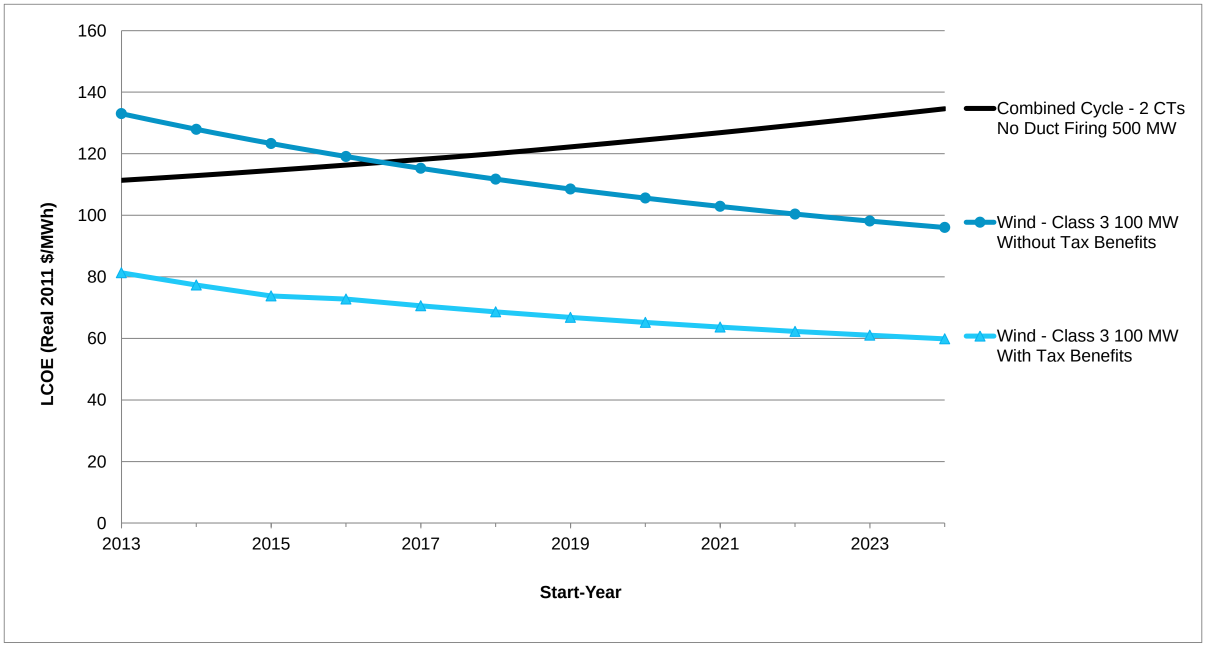
Source: Energy Commission.

Figure A-9: Effect of Tax Benefits on Solar Photovoltaic Thin-Film 20 Megawatt vs. Combined Cycle



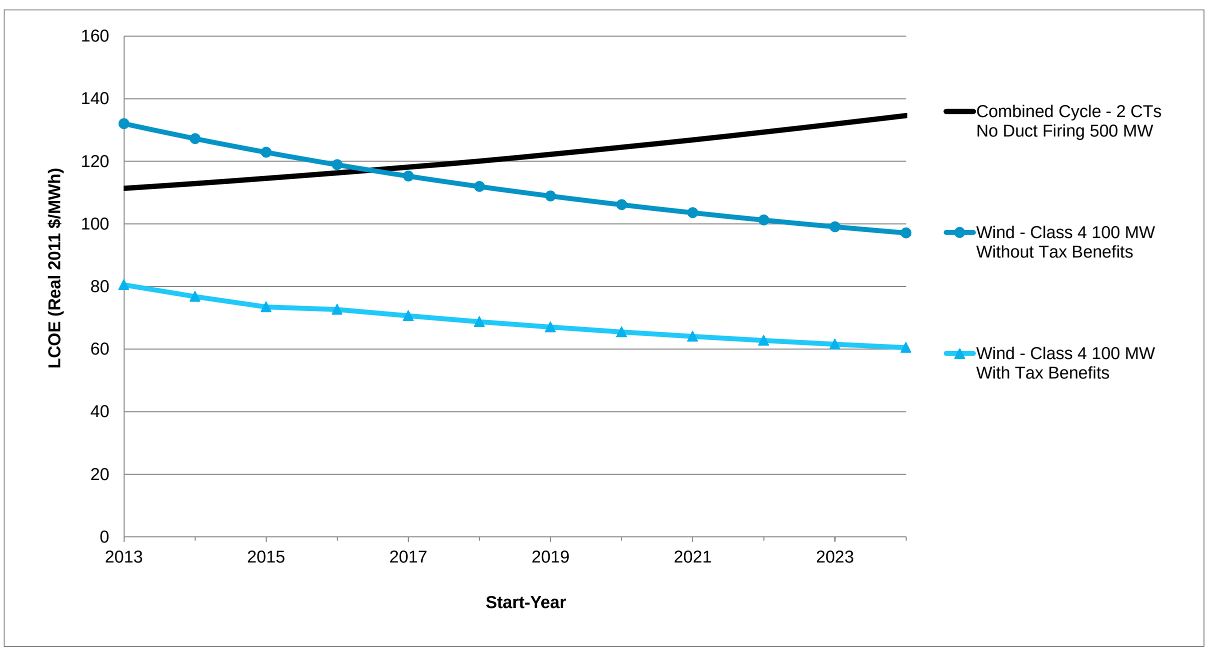
Source: Energy Commission.

Figure A-10: Effect of Tax Benefits on Wind - Class 3 vs. Combined Cycle



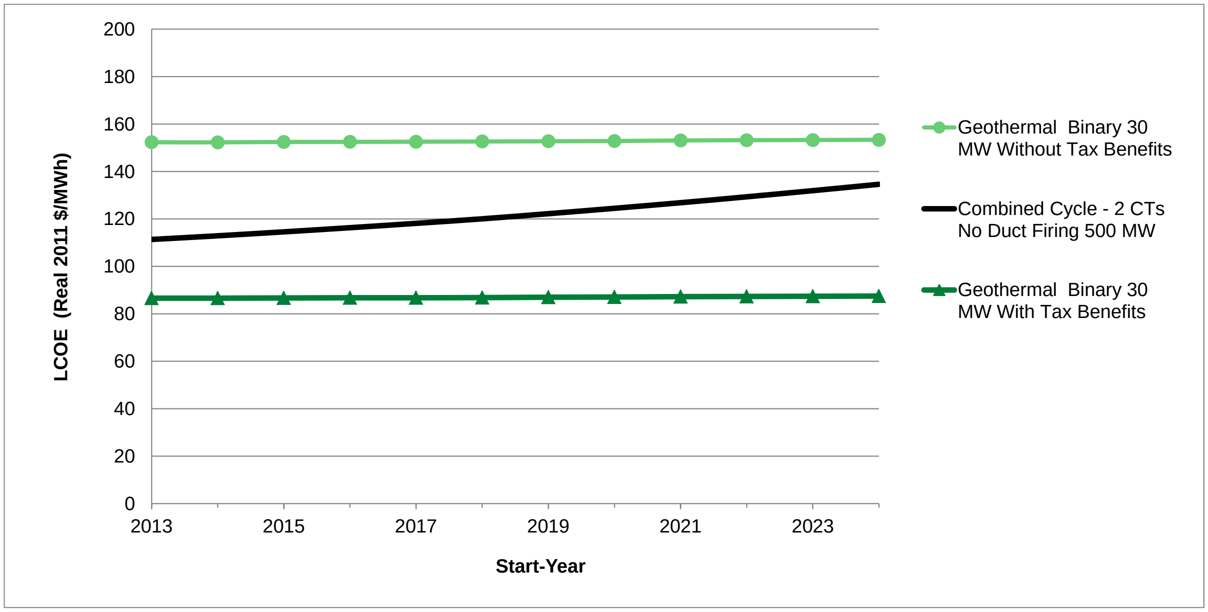
Source: Energy Commission.

Figure A-11: Effect of Tax Benefits on Wind - Class 4 vs. Combined Cycle



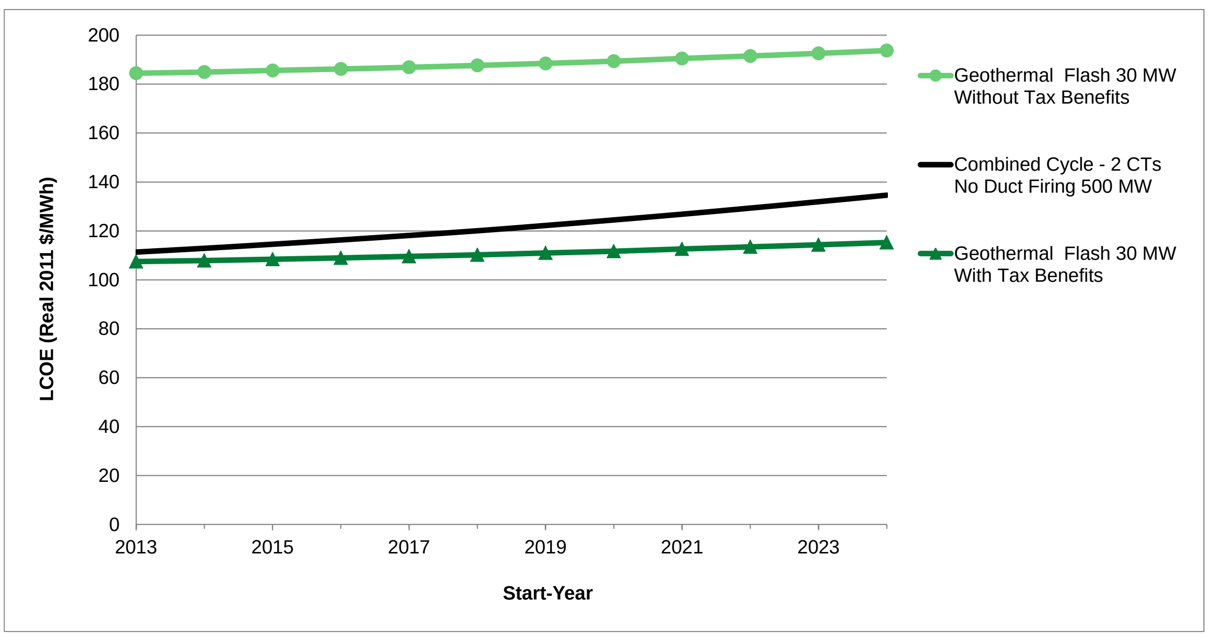
Source: Energy Commission.

Figure A-12: Effect of Tax Benefits on Geothermal Binary vs. Combined Cycle



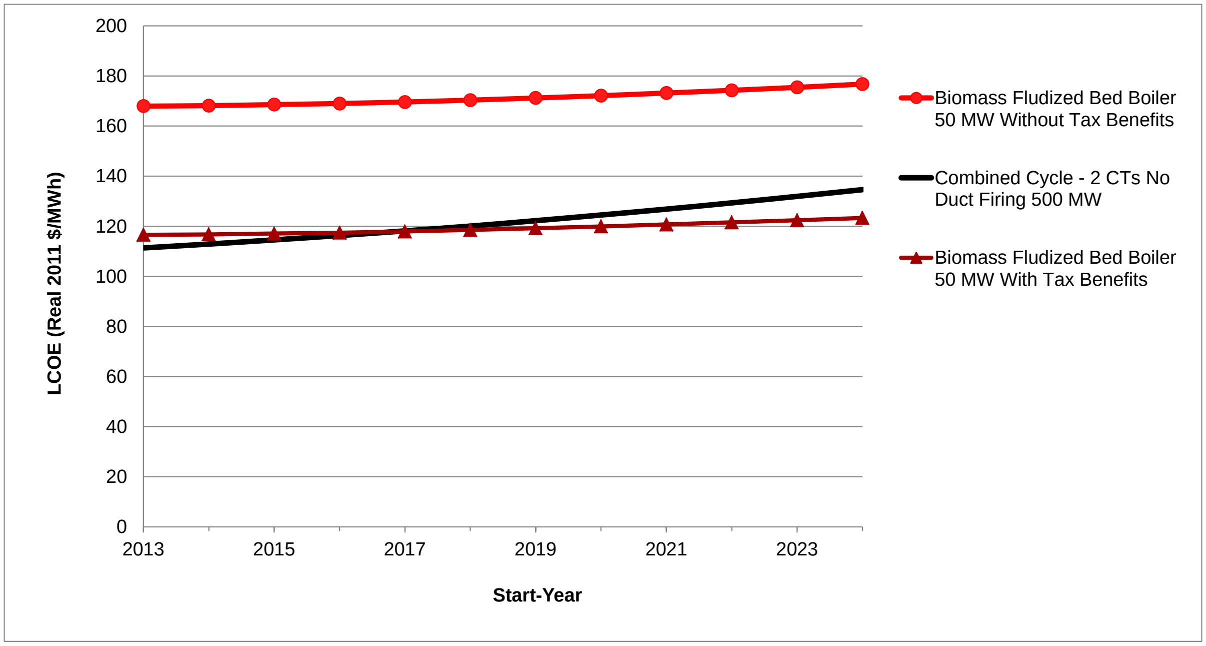
Source: Energy Commission.

Figure A-13: Effect of Tax Benefits on Geothermal Flash vs. Combined Cycle



Source: Energy Commission.

Figure A-14: Effect of Tax Benefits on Biomass vs. Combined Cycle



Source: Energy Commission.

APPENDIX B:
Gas-Fired Plants Technology Data

This appendix provides supporting information for the conventional and advanced gas-fired generation technology data assumptions provided in the *Cost of Generation Report*.

Plant Data

Plant data are the plant characteristics of the selected conventional gas-fired technologies selected for implementation in the COG Model. These data generally have 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: CT and CC. The five gas turbine technology cases selected for inclusion in the COG Model have the following basic designs:

- Conventional CT—One LM6000 Gas Turbine
- Conventional CT—Two LM6000 Gas Turbines
- Advanced CT—Two LMS100 Gas Turbines
- Conventional CC—Two F-Class Turbines
- Conventional CC with Duct Burners—Two F-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 was selected based on the general prevalence in the existing power plant fleet.

Gross Capacity (MW)

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

Table B-1: Gross Capacity Ratings for Typical Configurations

Technology Case	Gross Capacity
Conventional CT – One LM6000 Turbine	49.9 MW
Conventional CT – One LM6000 Turbine	100 MW
Advanced CT – 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

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 temperatures and that the turbines are not significantly derated by operating at high elevation.

Combined Cycle 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 obtained for the *2012 Integrated Energy Policy Report (2012 IEPR).* Fuel use and operational data for California facilities were updated as well from the Commission's *QFER* database.

For the *2012 IEPR*, as with preparing the *2007 IEPR*, staff again submitted to power plant developers/owners a data request for all the combined cycle (but not cogeneration) and CT power plants that were certified by the Energy Commission starting in 1999 and on-line since 2001 (47 total power plants). These plants are summarized in **Table B-2**, together with the in-service year and county location. This table includes all surveyed power plants, including the seven power plants that did not respond to the 2012 data requests.

Table B-2: Surveyed Power Plants[1]

Combined Cycle Plants (25)			Simple Cycle Plants (22)		
Plant Name	County	Operating	Plant Name	County	Operating
Los Medanos	Contra Costa	2001	Wildflower Larkspur[3]	San Diego	2001
Sutter	Sutter	2001	Wildflower Indigo[3]	Riverside	2001
Delta	Contra Costa	2002	Drews Alliance[3]	San Bernardino	2001
Moss Landing	Monterey	2002	Century Alliance[3]	San Bernardino	2001
La Paloma	Kern	2003	Hanford[3]	Kings	2001
High Desert	San Bernardino	2003	Calpeak Escondido[3]	San Diego	2001
MID Woodland[2,3]	Stanislaus	2003	Calpeak Border[3]	San Diego	2001
Sunrise	Kern	2003	Gilroy[3]	Santa Clara	2002
Blythe I	Riverside	2003	King City[3]	Monterey	2002
Elk Hills	Kern	2003	Henrietta	Kings	2002
Von Raesfeld[2]	Santa Clara	2005	Los Esteros	Santa Clara	2003
Metcalf	Santa Clara	2005	Tracy Peaker	San Joaquin	2003
Magnolia[2]	Los Angeles	2005	Kings River Peaker[2,3]	Fresno	2005
Malburg[2]	Los Angeles	2005	Ripon[2]	San Joaquin	2006
Pastoria	Kern	2005	Riverside[2]	Riverside	2006/11
Mountainview[4]	San Bernardino	2006	Niland[2]	Imperial	2007
Palomar[4]	San Diego	2006	Panoche	Fresno	2009
Cosumnes	Sacramento	2006	Starwood-Midway	Fresno	2009
Walnut[2]	Stanislaus	2006	Orange Grove	San Diego	2010
Roseville[2]	Placer	2007	Canyon[2]	Orange	2011
Gateway[4]	Contra Costa	2009	Mariposa	Alameda	2012
Otay Mesa	San Diego	2009	Almond[2]	Stanislaus	2012
Inland Empire	Riverside	2009/10			
Colusa[4]	Colusa	2010			
Lodi[2]	San Joaquin	2012			

Source: Energy Commission.

Notes:

1 – Not all plants surveyed responded.

2 – Muni-owned facility

3 – Emergency Siting or SPPE Cases

4 – IOU-owned facility

Capital cost information was requested from all 47 plants, while operating costs were requested from plants that began regular operations on January 1, 2011, or earlier. The data requests for the combined cycle and CT units were divided into capital costs and operating and maintenance costs, as summarized in **Table B-3**.

Table B-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 Type and Cost	Natural Gas Average Annual Price Data
Cooling Tower/Air Cooled Condenser Cost	Water Supply Source/Cost/Consumption
Water Treatment Facilities Cost (ZLD?)	Labor (Staffing and Cost)
Site Footprint and Land Cost	Nonfuel Annual Operating Costs (Consumables, regulatory etc.)
Total Construction Costs (Labor/Equipment/etc.)	Normal Annual Maintenance Costs, including Major Scheduled Overhaul Frequency/Cost
Cost of Site Preparation	Fixed versus Variable O&M Costs Definitions
Cost of Pipeline Linear Construction (natural gas, water, sewer)	
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 to the design of that plant. For example, CT 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 these data were 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 under Outage Rates.

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 SOF was derived from NERC GADS data for California generation resources:

- NERC GADS Vintage 2002 – 2007 California CCs 500 – 900 MW: 6.02 percent
- NERC GADS 2002 – 2007 California CTs 45 – 99 MW: 2.72 percent
- NERC GADS 2002 – 2007 California 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 nonoperational hours due to curtailments when developing the rate. This is particularly important for low capacity factor resources such as CT units. The EFORd values are used in the model.

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

Capacity Factor (Percentage)

The actual capacity factors (CFs) were determined for the existing California conventional LM6000 CT power plants and F-Class combined cycle power plants, based on the monthly QFER data from 2001 to 2011 for 25 CT facilities and 15 combined cycle facilities and are provided in **Table B-4** and **Table B-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 POUs; and Barre, Center, Etiwanda, and Mira Loma are IOUs. The other power plants are all merchant facilities.

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

Table B-4: Historical Capacity Factors for Simple Cycle Turbines—2001 – 2011

		Capacity Factors											
Power Plant Name	**MW**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**Avg**
Windflower Larkspur	90		1.2%	4.0%	4.7%	3.8%	2.9%	6.0%	8.0%	7.6%	6.1%	4.3%	4.4%
Windflower Indigo	135		0.3%	5.9%	6.3%	4.7%	4.4%	6.9%	9.9%	5.7%	5.4%	3.4%	4.8%
Hanford	92	3.2%	4.9%	2.2%	1.2%	4.0%	2.6%	4.4%	5.7%	7.5%	2.4%	1.3%	3.6%
Calpeak Enterprise	50									3.8%	3.9%	9.5%	5.7%
Calpeak Border	50									4.2%	2.8%	6.6%	4.5%
Gilroy	141.9		4.9%	5.4%	5.6%	4.1%	4.2%	7.2%	7.8%	4.8%	2.5%	2.6%	4.9%
King City	47.3		3.9%	4.0%	5.0%	3.7%	3.8%	5.4%	5.8%	4.0%	1.8%	1.2%	3.9%
Henrietta	98		3.4%	2.3%	1.3%	1.5%	2.2%	2.4%	5.6%	6.4%	1.8%	1.9%	2.9%
Los Esteros	192			9.4%	16.1%	15.9%	4.6%	3.9%	4.8%	4.3%	2.4%	4.0%	6.5%
Kings River Peaker	97									19.2%	4.3%	7.5%	10.4%
Starwood-Midway	120									3.2%	3.8%	7.1%	4.7%
Niland Peaker	93								9.2%	5.6%	3.7%	4.7%	5.8%
MID Ripon	100						2.0%	3.1%	3.9%	4.9%	2.5%	4.2%	3.4%
Orange Grove	95										7.7%	4.7%	6.2%
Anaheim	49.27	21.9%	29.9%	25.4%	13.1%	12.3%	12.8%	11.4%	12.0%	15.8%	9.6%	6.3%	15.5%
Barre	49							2.1%	1.1%	0.7%	1.5%	1.5%	1.4%
Center	49							1.9%	1.1%	0.8%	1.3%	1.6%	1.3%
Creed	48.1			3.3%	2.4%	2.2%	2.7%	3.1%	3.8%	2.9%	1.8%	1.2%	2.6%
Etiwanda	49							1.6%	0.9%	0.3%	1.0%	0.6%	0.9%
Feather	48.1			3.7%	3.9%	3.0%	3.7%	6.1%	6.5%	6.5%	3.2%	3.1%	4.4%
Goose Haven	48.1			3.1%	2.6%	2.5%	2.8%	3.4%	3.7%	2.8%	1.7%	1.4%	2.7%
Lambie	48.1			3.2%	3.7%	3.6%	2.8%	3.5%	3.5%	3.3%	0.3%	1.3%	2.8%
Riverview	47.3			3.7%	4.1%	4.9%	4.3%	6.4%	7.1%	4.5%	2.0%	2.7%	4.4%
Wolfskill	48.1			3.8%	5.0%	3.7%	4.0%	4.9%	6.1%	4.6%	1.8%	2.3%	4.0%
Glenarm	94.6				5.4%	2.8%	5.0%	4.5%	4.1%	12.1%	9.5%	10.2%	6.7%
Malaga	98						7.6%	15.5%	17.6%	19.0%	4.3%	7.5%	11.9%
Mira Loma	49							1.7%	1.0%	0.5%	1.1%	1.2%	1.1%
Yuba City	48.1			4.3%	4.2%	8.2%	5.2%	5.9%	8.3%	7.4%	6.7%	3.5%	6.0%
Panoche Energy Center	400									4.5%	5.9%	9.0%	6.5%

Source: Energy Commission.

Table B-5: Historical Capacity Factors for Combined Cycle Plants: 2001 – 2011

		Capacity Factors											
Power Plant Name	**MW**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**Avg**
Moss Landing Power Plant	1060		30.1%	61.4%	58.8%	55.7%	61.2%	74.5%	65.9%	50.1%	40.0%	22.8%	52.0%
High Desert Power Project	830			35.3%	57.5%	55.6%	59.8%	67.6%	70.1%	63.4%	49.9%	28.4%	54.2%
Sutter	578	37.1%	84.1%	72.7%	77.8%	55.4%	48.0%	60.7%	66.0%	52.9%	41.4%	21.8%	56.2%
Los Medanos	540	25.2%	82.5%	74.9%	82.5%	82.9%	67.8%	80.4%	71.7%	77.5%	75.9%	61.5%	71.2%
La Paloma Generating	1124			34.6%	57.2%	46.4%	57.0%	62.6%	62.6%	64.4%	53.7%	13.3%	50.2%
Delta Energy Center	840		46.0%	80.1%	85.1%	81.6%	73.6%	80.2%	73.3%	76.3%	60.8%	63.4%	72.0%
Sunrise Power	585			37.8%	72.7%	76.9%	82.1%	83.6%	82.1%	81.8%	74.3%	31.0%	69.1%
Blythe Energy LLC	520				27.9%	20.4%	24.2%	27.1%	31.3%	31.5%	28.9%	28.3%	27.4%
Elk Hills Power, LLC	550				90.9%	81.8%	78.9%	85.2%	81.1%	78.8%	85.7%	73.9%	82.0%
Metcalf Energy Center	605					44.0%	54.3%	67.0%	74.3%	64.8%	59.1%	36.2%	57.1%
Pastoria	750					38.3%	70.6%	73.5%	74.6%	75.8%	66.0%	44.3%	63.3%
Otay Mesa	590									17.8%	49.3%	47.1%	38.1%
Mountainview	1056					1.7%	55.6%	72.0%	76.4%	65.7%	69.1%	52.8%	56.2%
Palomar	546						56.4%	76.3%	82.0%	75.2%	73.0%	49.2%	68.7%
Magnolia	328					14.2%	40.9%	64.8%	71.5%	71.4%	75.8%	46.2%	55.0%
Colusa	660										1.6%	45.2%	23.4%
Cosumnes	500						57.8%	85.0%	87.6%	78.5%	85.4%	76.9%	78.5%
Gateway	619									56.9%	70.8%	60.5%	62.7%
Inland Empire Energy Center	800									50.7%	77.0%	44.5%	57.4%

Source: Energy Commission.

Table B-6: Estimated Capacity Factors

Technology Case	Owner	Estimated Capacity Factor		
		Mid	High	Low
Conventional CT (both sizes)	Merchant	5.0%	2.5%	7.5%
	POU	7.5%	4.0%	14.%
	IOU	1.0%	1.0%	1.0%
Advanced CT	Merchant	7.5%	3.8%	11.3%
	POU	11.3%	6.0%	21.0%
	IOU	1.5%	1.5%	1.5%
Conventional CC	All Owners	57%	40%	71%
Conventional CC With Duct Burners	All Owners	57%	40%	71%

Source: Energy Commission.

Note: High and low are based on cost implications not on the specific value of the CF.

The increase in both CT and CC CF seen in the 2009 report in both the *QFER* and California ISO *Annual Report on Market Issues and Performance* has reversed in recent years. The recommended CFs for both types of plants are now lower than those used in the previous version of the COG Model. The advanced CT CFs were increased 50 percent above the assumed conventional CT CFs because of an assumption of increased use due to higher efficiency and the experience of the CTs in the database.

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 were determined through the difference in the reported gross vs. reported net generation for the existing California conventional LM6000 CT power plants and F-Class CC power plants, based on the monthly *QFER* data from 2001 to 2008 for 25 CT facilities and 15 CC facilities. Based on these data, staff recommends the average-cost, high-cost, and low-cost plant-side losses shown in **Table B-7**. Staff does not have data to suggest significantly different plant-side loss factors for high-efficiency, CC facilities. The advanced CT facilities may have increased plant-side losses due to the power required for the turbine intercooling 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 recommended.

Table B-7: Summary of Recommended Plant-Side Losses (Percent)

Technology	Average	High	Low
All CC	2.9%	4.0%	2.0%
All CT	3.4%	4.2%	2.3%

Source: Energy Commission.

Heat Rate (Btu/kWh)

The actual heat rates, reported as HHV, determined for the existing California conventional LM6000 CT power plants and F-Class CC power plants, based on the monthly QFER data from 2001 to 2011 for 25 CT facilities and 15 CC facilities, are provided in **Table B-8** and **Table B-9.** The heat rates were derived using the following simple equation:

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

Table B-8: Simple Cycle Facility Heat Rates (Btu/kWh, HHV)

		Heat Rates														
Power Plant Name	**MW**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**Avg.**
Windflower Larkspur	90		9,972	10,065	10,011	10,236	10,208	10,047	10,019	10,208	9,603	10,019	10,587	10,617	10,906	**10,267**
Windflower Indigo	135		10,091	10,236	10,061	10,137	10,154	9,934	10,000	10,154	9,934	10,000	10,459	10,628	10,803	**10,250**
Hanford	92	10,295	10,263	10,279	10,127	10,675	10,220	10,798	10,137	10,220	10,798	10,216	10,571	11,049	11,377	**10,526**
Calpeak Enterprise	50									10,901	10,780	10,743	10,847	10,894	10,874	**10,872**
Calpeak Border	50									10,916	10,844	10,772	10,973	10,841	10,768	**10,861**
Gilroy	141.9		10,187	10,341	10,029	9,970	10,102	10,073	10,125	10,102	11,681	10,022	10,329	10,717	11,609	**10,348**
King City	47.3		10,109	10,075	10,191	10,259	10,156	9,749	9,862	10,178	9,749	9,862	10,174	10,584	11,908	**10,307**
Henrietta	98		10,177	10,263	10,419	10,582	10,291	10,491	10,434	10,291	10,491	10,351	10,467	10,559	11,445	**10,513**
Los Esteros	192			10,345	10,275	10,404	10,480	10,309	10,346	10,480	10,309	10,346	10,197	10,599	10,121	**10,342**
Kings River Peaker	97									*	9,999	9,957	9,875	*	*	**9,875**
Starwood-Midway	120												10,775	10,879	10,842	**10,832**
Niland Peaker	93								10,257			10,031	10,040	10,034	10,263	**10,149**
MID Ripon	100						12,749	12,494	11,629	12,749	12,494	11,908	11,438	11,746	11,526	**11,930**
Orange Grove	95													9,775	10,781	**10,278**
Anaheim	49.27	9,178	9,208	9,325	9,744	10,170	10,213	9,499	9,424	10,213	9,499	9,424	9,358	9,486	9,534	**9,558**
Barre	49							11,744	12,057		11,744	12,059	12,618	11,590	11,366	**11,875**
Center	49							10,640	10,587		10,640	10,587	12,392	12,090	11,282	**11,398**
Creed	48.1			10,124	10,075	10,170	10,749	10,251	10,247	10,749	10,280	10,247	10,211	10,355	11,870	**10,450**
Etiwanda	49							11,051	12,062		10,760	12,105	14,643	12,254	12,829	**12,568**
Feather	48.1			9,578	9,748	9,448	9,487	10,308	10,258	9,487	10,349	10,258	10,433	10,930	11,271	**10,162**
Goose Haven	48.1			10,095	10,156	10,175	10,101	10,358	10,304	10,101	10,213	10,304	10,408	10,479	12,082	**10,462**
Lambie	48.1			9,953	10,089	10,169	10,317	10,145	10,152	10,317	10,139	8,949	10,468	10,185	11,941	**10,380**
Riverview	47.3			10,235	10,015	10,069	11,585	10,101	10,217	11,585	10,109	10,217	10,162	10,532	11,720	**10,515**
Wolfskill	48.1			9,942	10,150	10,297	10,154	10,319	10,208	10,154	10,331	10,208	10,284	10,364	11,635	**10,373**
Glenarm	94.6				11,969	12,434	10,226	10,439	10,604	8,956	10,500	10,679	11,760	11,293	11,843	**11,321**
Malaga	98						9,470	9,999	9,957	8,395	9,999	9,957	9,875	9,388	9,685	**9,729**
Mira Loma	49							11,138	11,992		11,138	11,992	13,560	12,120	11,743	**12,111**
Yuba City	48.1			9,710	9,549	9,452	9,338	10,071	10,051	9,338	10,088	10,051	10,482	10,492	11,103	**10,028**
Panoche Energy Center	400												10,189	9,863	9,602	**9,884**

Source: Energy Commission.

Table B-9: Combined Cycle Facility Heat Rates (Btu/kWh, HHV)

		Heat Rates														
Power Plant Name	**MW**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**Average**
Moss Landing	1060		7,136	7,081	7,069	7,099	7,052	7,084	7,127	7,520	7,437	8,061	7,715	7,478	7,685	**7,253**
High Desert Power Project	830			7,321	7,348	7,356	7,343	7,047	7,055	7,343	7,083	7,055	7,232	6,837	7,438	**7,220**
Sutter	578	6,982	7,089	7,156	7,193	7,458	7,451	7,406	7,430	7,451	7,406	7,430	7,454	7,569	7,745	**7,357**
Los Medanos	540	6,947	7,090	7,239	7,191	7,290	7,337	7,210	7,218	7,337	7,210	7,288	7,184	7,168	7,256	**7,194**
La Paloma Generating	1124			7,198	7,133	7,234	7,167	7,166	7,172	7,167	7,165	7,172	7,184	7,213	7,272	**7,193**
Delta Energy Center	840		7,295	7,310	7,289	7,288	7,324	7,317	7,321	7,334	7,313	7,630	7,308	7,381	7,374	**7,321**
Sunrise Power	585			7,524	7,213	7,206	7,295	7,274	7,266	7,295	7,262	7,266	*	7,205	7,785	**7,346**
Blythe Energy LLC	520				7,416	7,419	7,436	7,825	7,808	7,436	7,825	7,833	7,399	7,329	7,397	**7,504**
Elk Hills Power, LLC	550				6,855	6,990	7,051	7,050	7,063	7,051	7,050	7,048	7,001	7,008	7,187	**7,025**
Metcalf Energy Center	605					7,028	7,048	7,042	6,884	7,048	7,040	6,893	7,172	7,304	7,478	**7,137**
Pastoria	750					7,230	7,050	7,062	7,032	7,050	7,187	7,025	6,951	7,026	7,206	**7,079**
Otay Mesa	590												6,968	6,960	7,290	**7,072**
Mountainview	1056					12,056	7,252	7,063	7,141	7,252	7,063	7,141	7,213	7,144	7,209	**7,868**
Palomar	546						7,069	7,038	6,959	7,069	7,042	6,959	7,016	6,973	7,135	**7,032**
Magnolia	328					7,614	7,340	7,456	7,233	7,340	7,456	7,233	7,200	7,199	7,115	**7,308**
Colusa	660													7,812	7,141	**7,476**
Cosumnes	500						7,198	7,042	7,047	7,198	7,042	7,047	7,026	6,952	7,027	**7,049**
Gateway	619												7,123	7,011	7,128	**7,087**
Inland Empire Energy Center	800												7,040	6,802	6,902	**6,915**

Source: Energy Commission.

Table B-10 provides the mid, high, and low case heat rates that were recommended for use in the COG 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.

Table B-10: Summary of Recommended Heat Rates (Btu/kWh, HHV)

Technology	Mid[a]	High[a]	Low[b]
Conventional CT[c]	10,585	11,890	9,980
Advanced CT	9,880	10,200	9,600
Conventional CC	7,250	7,480	7,030
Conventional CC W/ Duct Firing	7,250	7,480	7,030

Source: Energy Commission.

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 CT 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 CT 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.

Plant Cost Data

The plant costs data were obtained from the surveys as described in *Combined and Simple Cycle Data Collection* previously. In addition, costs are adjusted for the physical performance parameters, and the instant costs are converted to installed costs using the financial parameters described in this report. The plant cost data are now identified for average, high, and low cases; therefore, the specificity of the design has been simplified. All projects are assumed to have SCR for control of NO_x emissions and an oxidation catalyst for control of carbon monoxide emissions. Plant costs also include acquisition of ERCs, both for criteria pollutants in the capital costs and for GHGs in the annual operational costs.

Combined Cycle Capital Costs

The assumed design configuration of the two combined CC cases are 1) a 500 MW plant without duct firing that uses two F-frame turbines with one steam generator, and 2) a 500 MW plant with 50 MW of duct firing (for a total of 550 MW) that uses two F-frame turbines with one steam generator**.** The projects with announced instant or installed cost data were evaluated to determine the recommended mid, high, and low capital cost values for the three combined CC cases.

Table B-11 shows the estimated instant costs for the two CC configurations for 2011, which are in 2011 dollars. These cost estimates exclude land acquisition, environmental permitting, and air emission reductions credit acquisition, which are incorporated separately into the COG Model and usually vary for local and jurisdictional circumstances.

Table B-11: Total Instant Costs for Combined Cycle Cases

Technology Case	Mid ($kW)	High ($kW)	Low ($kW)
Conventional 500 MW CC Without Duct Firing			
Without Ancillary Costs	$841.00	$857.00	$699.00
Interconnection Costs	$61.00	$135.00	$39.00
Land Costs	$4.00	$9.00	$1.00
Licensing Costs	$46.00	$87.00	$36.00
Instant Costs With Ancillary Costs	**$951.00**	**$1,089.00**	**$775.00**
Conventional 550 MW CC With Duct Firing			
Without Ancillary Costs	$824.00	$852.00	$672.00
Interconnection Costs	$56.00	$128.00	$35.00
Land Costs	$3.00	$8.00	$1.00
Licensing Costs	$49.00	$90.00	$39.00
Instant Costs With Ancillary Costs	**$933.00**	**$1,079.00**	**$747.00**

Source: Energy Commission.

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

Simple Cycle Capital Costs

The assumed design configuration of the three CT cases are 1) a 49.9 MW plant that uses one LM6000 gas turbine with chiller air pretreatment, 2) a 100 MW plant that uses two LM6000 gas turbines with chiller air pretreatment, and 3) a 200 MW plant that uses two LMS100 gas turbines with evaporative cooler air pretreatment**.** The projects with announced instant or installed cost data were evaluated to determine the recommended mid, high, and low capital cost values for the three CT cases.

Table B-12 provides the assumed design configuration of the three CT 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 CT cases are shown in **Table B-12**.

Table B-12: Base Case Configurations—Simple Cycle

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

Source: Energy Commission.

Table B-13 shows the estimated instant costs for the three CT cases in the COG Model, which are for 2011 and are in 2011 dollars. As with the CC data, these costs estimates exclude land acquisition, environmental permitting, and air emission reductions credit acquisition, which are incorporated separately into the COG Model and usually vary for local and jurisdictional circumstances. The advanced CT case cost is based on very limited data for a different advanced gas turbine type. The significantly lower cost for the advanced CT 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 CT costs.

Table B-13: Total Instant Costs for Simple Cycle Cases

Technology Case	Mid ($/kW)	High ($/kW)	Low ($/kW)
Conventional 49.9 MW CT			
Without Ancillary Costs	$921.00	$1,100.00	$622.00
Interconnection Costs	$159.00	$403.00	$95.00
Land Costs	$8.00	$22.00	$4.00
Licensing Costs	$75.00	$75.00	$75.00
Instant Costs With Ancillary Costs	**$1,163.00**	**$1,653.00**	**$772.00**
Conventional 100 MW CT			
Without Ancillary Costs	$993.00	$1,287.00	$664.00
Interconnection Costs	$87.00	$216.00	$52.00
Land Costs	$4.00	$11.00	$2.00
Licensing Costs	$75.00	$128.00	$51.00
Instant Costs With Ancillary Costs	**$1,159.00**	**$1,642.00**	**$770.00**
Advanced 200 MW CT			
Without Ancillary Costs	$738.00	$975.00	$430.00
Interconnection Costs	$152.00	$338.00	$97.00
Land Costs	$2.00	$5.00	$1.00
Licensing Costs	$48.00	$105.00	$23.00
Instant Costs With Ancillary Costs	**$941.00**	**$1,423.00**	**$550.00**

Source: Energy Commission.

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

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 B-14** provides the average-cost, high-cost, and low-cost heat rates that were recommended for use in the COG Model.

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.

Table B-14: Summary of Recommended Construction Periods (Months)

Technology	Mid	High	Low
Conventional CC	24	36	20
Conventional CC With Duct Firing	24	36	20
Conventional CT[a]	9	16	4
Advanced CT[b]	15	20	12

Source: Energy Commission.

Note:

[a] The conventional CT 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.

Fixed and Variable Operating and Maintenance 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 nonstaffing costs. Nonstaffing costs are composed of equipment, regulatory filings, and 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. **Table B-15** and **Table B-16** summarize the fixed and variable O&M components, respectively. Fixed O&M is composed of two components: staffing costs and nonstaffing costs. Nonstaffing costs are composed of equipment, regulatory filings, and ODCs. As with the CC fixed costs, staffing costs for CT 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 historical 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

However, the variable costs for the CC plants exclude the water supply costs because the underlying water rates vary by locality or region and are computed within the model. For the CT plants, the water costs are so insignificant that they do not have an appreciable effect on the variable O&M costs.

Table B-15: Fixed Operations and Maintenance

Technology	Mid	High	Low
Small CT	$26.85	$71.09	$9.44
Conventional CT	$25.95	$69.57	$9.14
Advanced CT	$23.87	$66.11	$8.45
Conventional CC	$32.69	$77.96	$13.04
Conventional CC With Duct Firing	$32.69	$77.96	$13.04

Source: Energy Commission.

Table B-16: Variable Operations and Maintenance

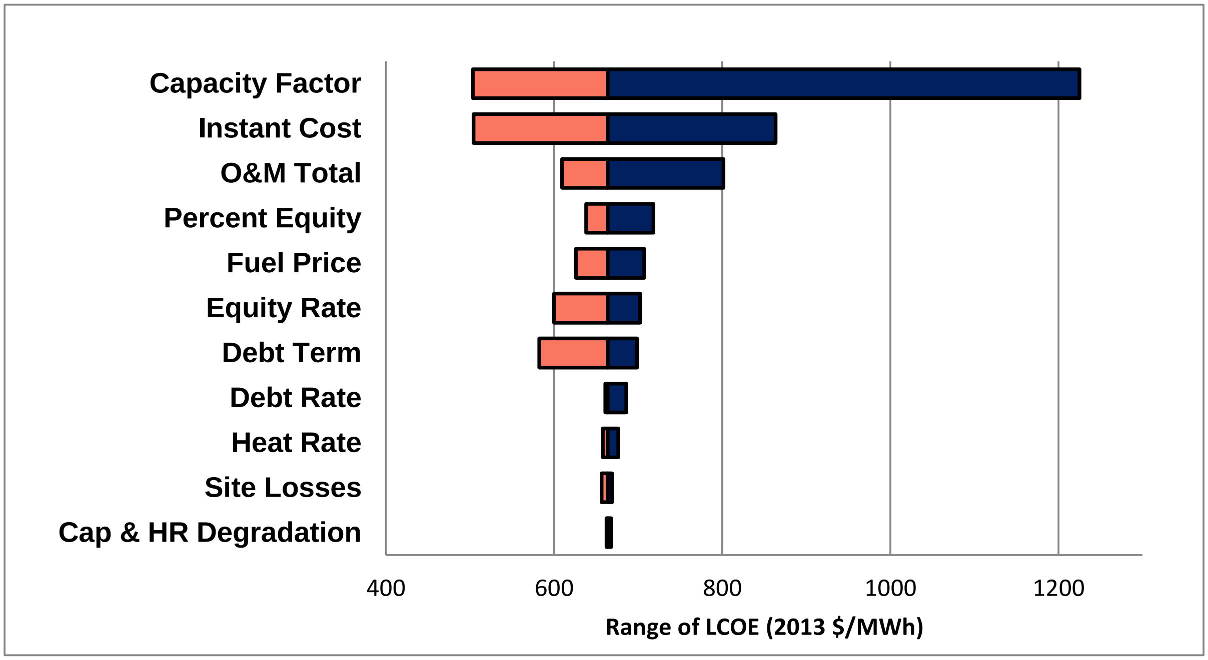
Technology	Mid	High	Low
Small CT	$0.00	$0.00	$0.00
Conventional CT	$0.00	$0.00	$0.00
Advanced CT	$0.00	$0.00	$0.00
Conventional CC	$0.58	$1.79	$0.18
Conventional CC With Duct Firing	$0.58	$1.79	$0.18

Source: Energy Commission.

APPENDIX C: Tornado Diagrams

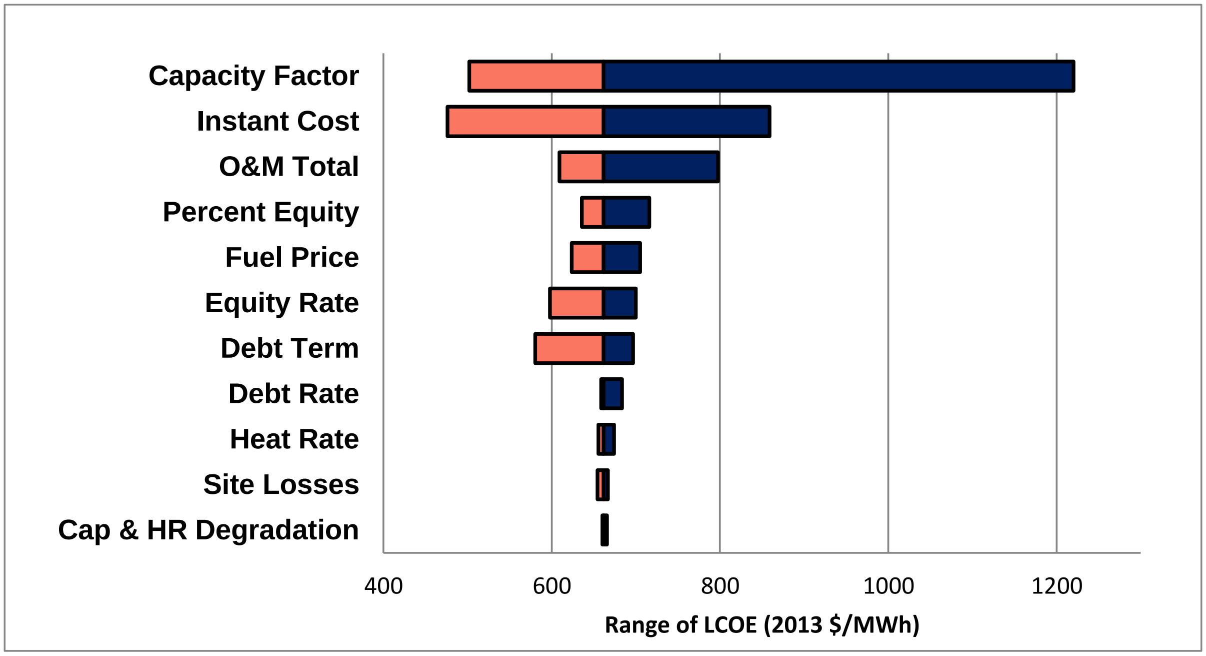
This appendix provides a complete set of tornado diagrams. All of the figures are for a start year of 2013 and are in nominal (2013) dollars. Each bar in the diagram is derived by resetting the high or low driver in the mid-cost case of the COG Model to the maximum or minimum value, respectively.

Figure C-1: Tornado Diagram—Generator Turbine 49.9 MW



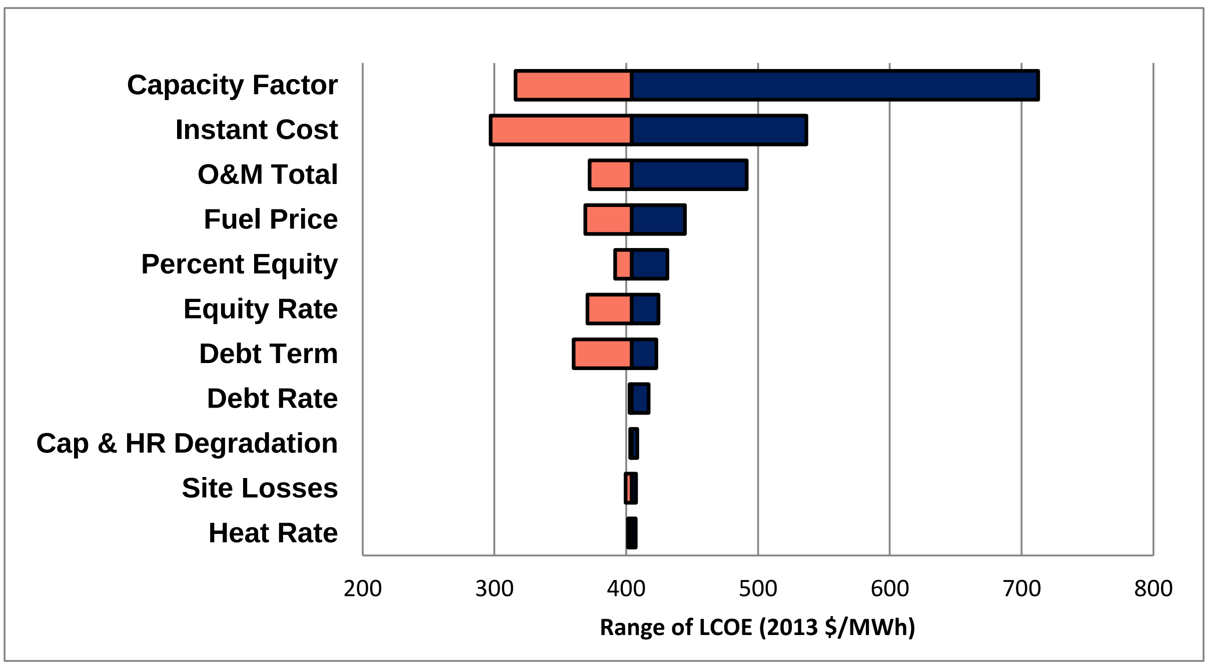
Source: Energy Commission.

Figure C-2: Tornado Diagram—Generator Turbine 100 MW



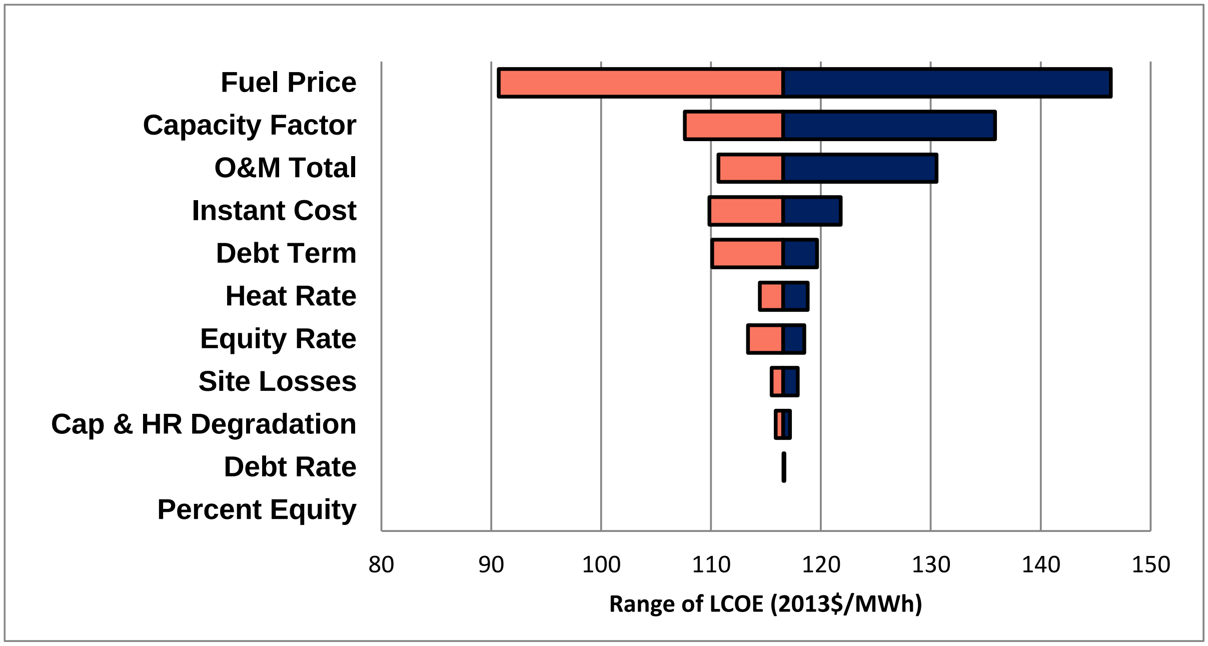
Source: Energy Commission.

Figure C-3: Tornado Diagram—Advanced Generation Turbine



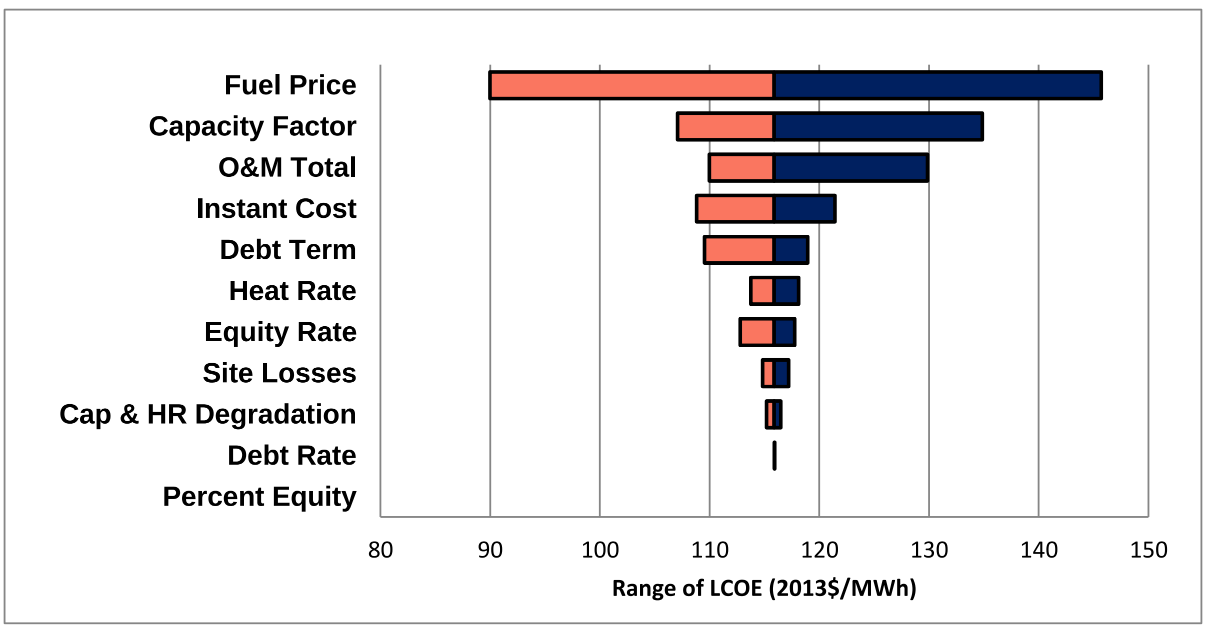
Source: Energy Commission.

Figure C-4: Tornado Diagram—Combined Cycle 500 MW



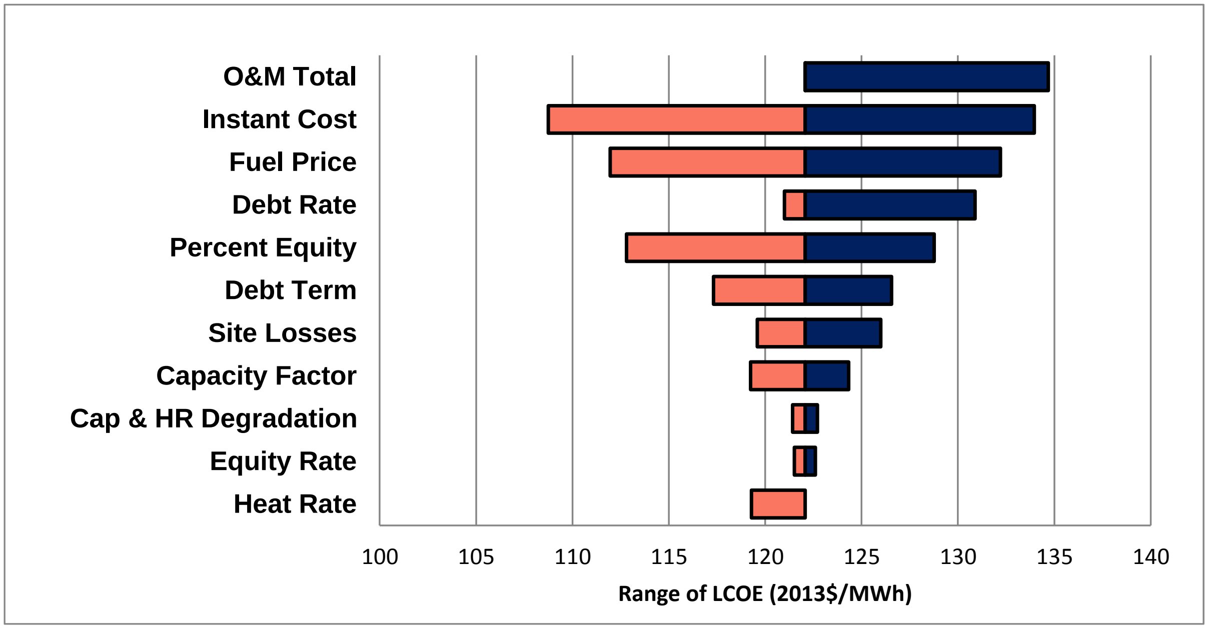
Source: Energy Commission.

Figure C-5: Tornado Diagram—Combined Cycle With Duct Firing 550 MW



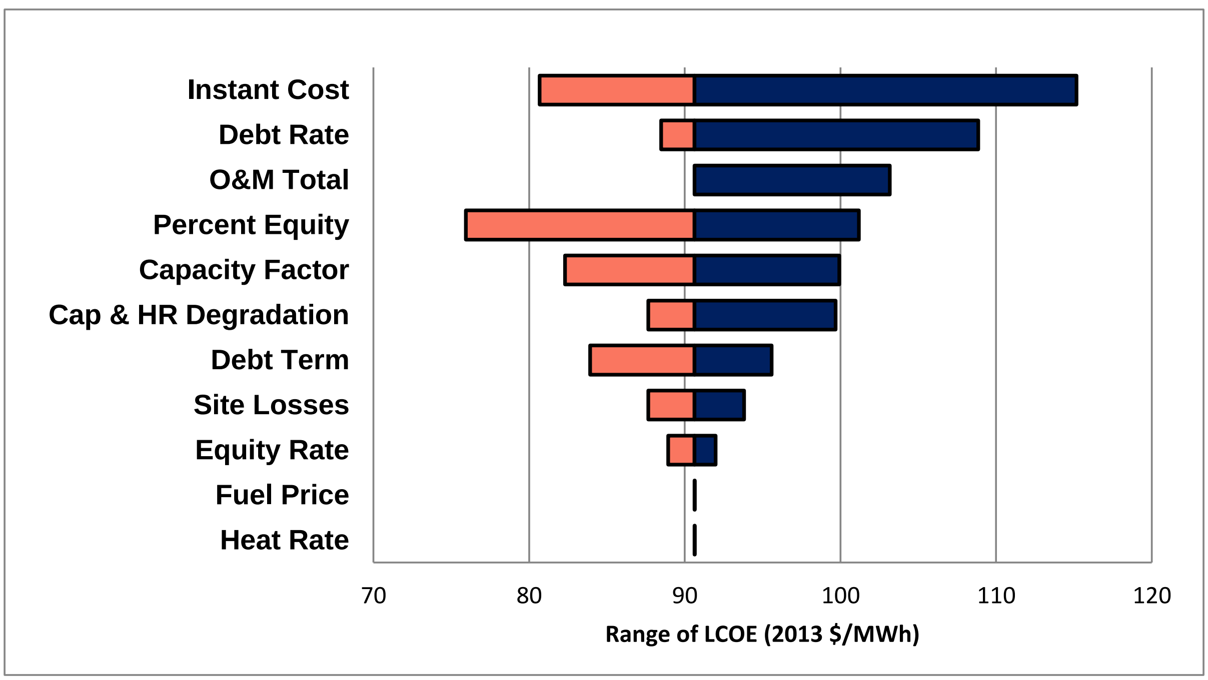
Source: Energy Commission.

Figure C-6: Tornado Diagram—Biomass Fluidized Bed 50 MW



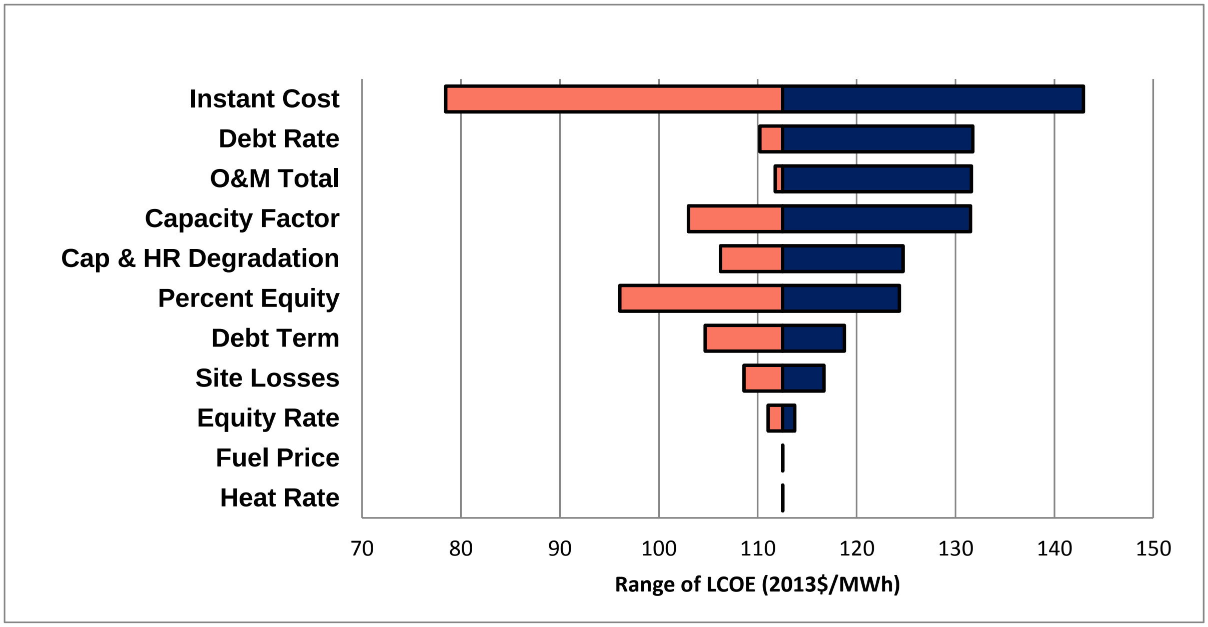
Source: Energy Commission.

Figure C-7: Tornado Diagram—Geothermal Binary 30 MW



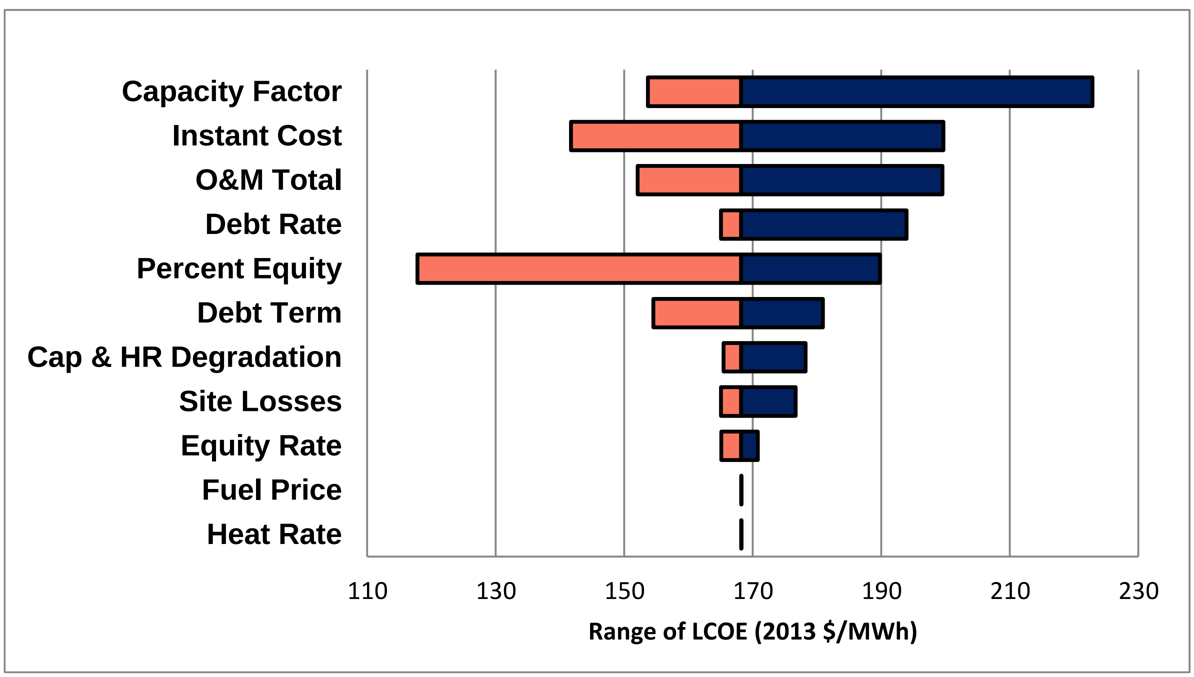
Source: Energy Commission.

Figure C-8: Tornado Diagram—Geothermal Flash 30 MW



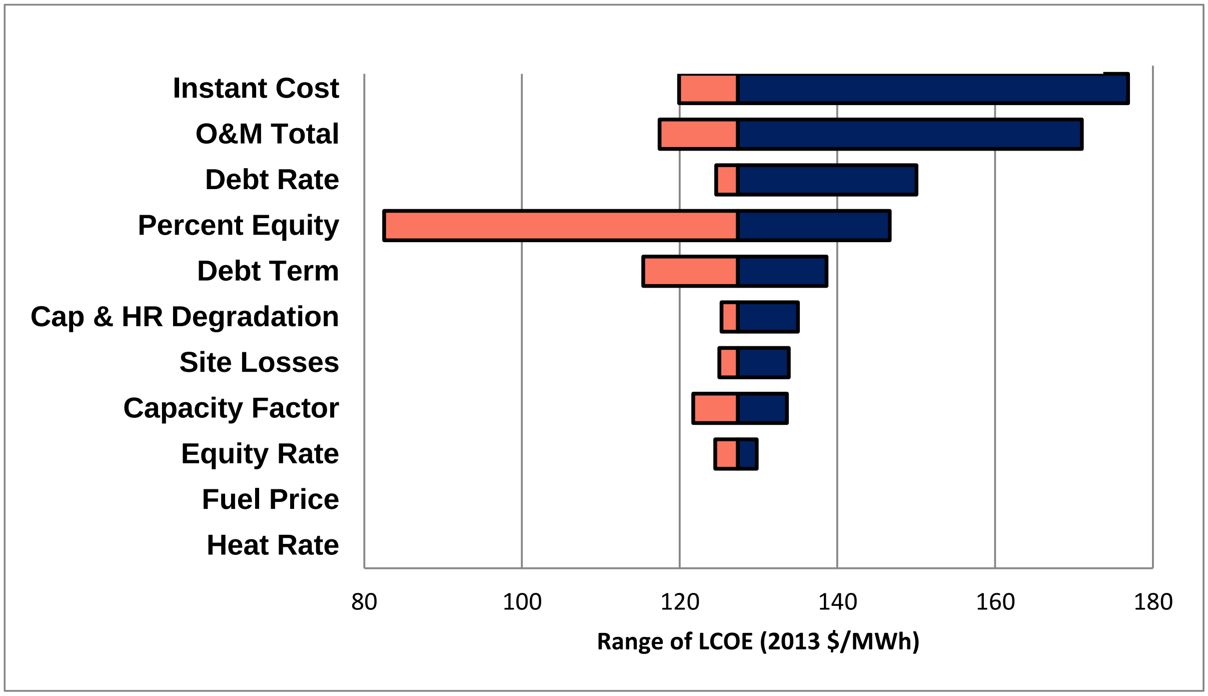
Source: Energy Commission.

Figure C-9: Tornado Diagram—Solar Parabolic Trough Without Storage 250 MW



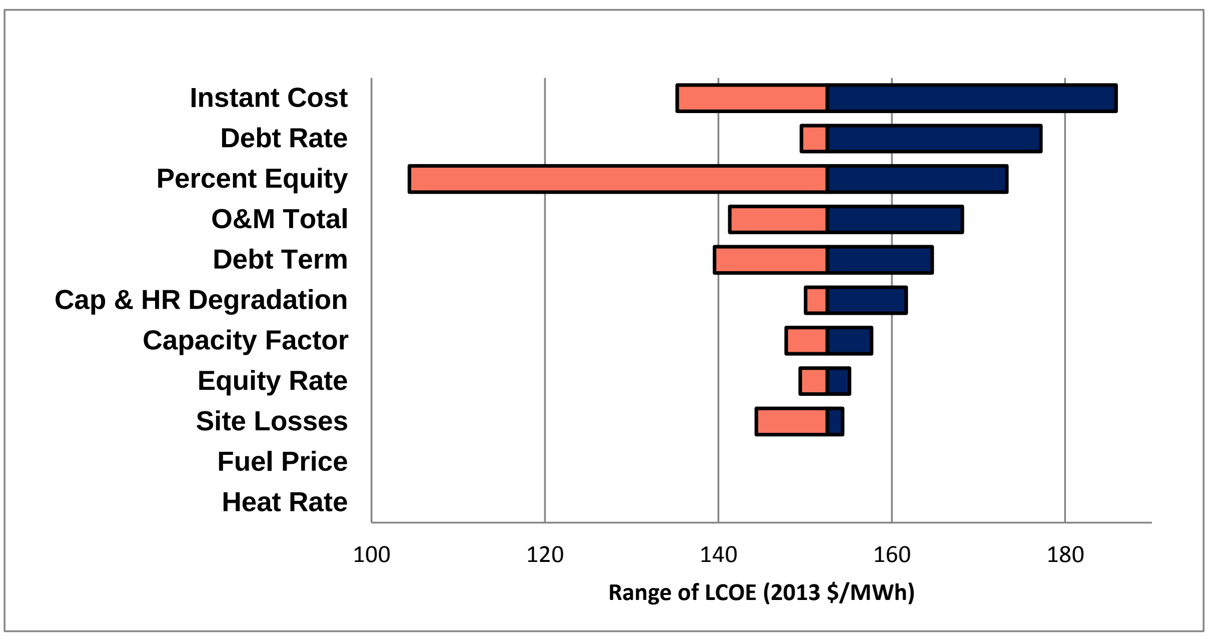
Source: Energy Commission.

Figure C-10: Tornado Diagram—Solar Parabolic Trough With Storage 250 MW



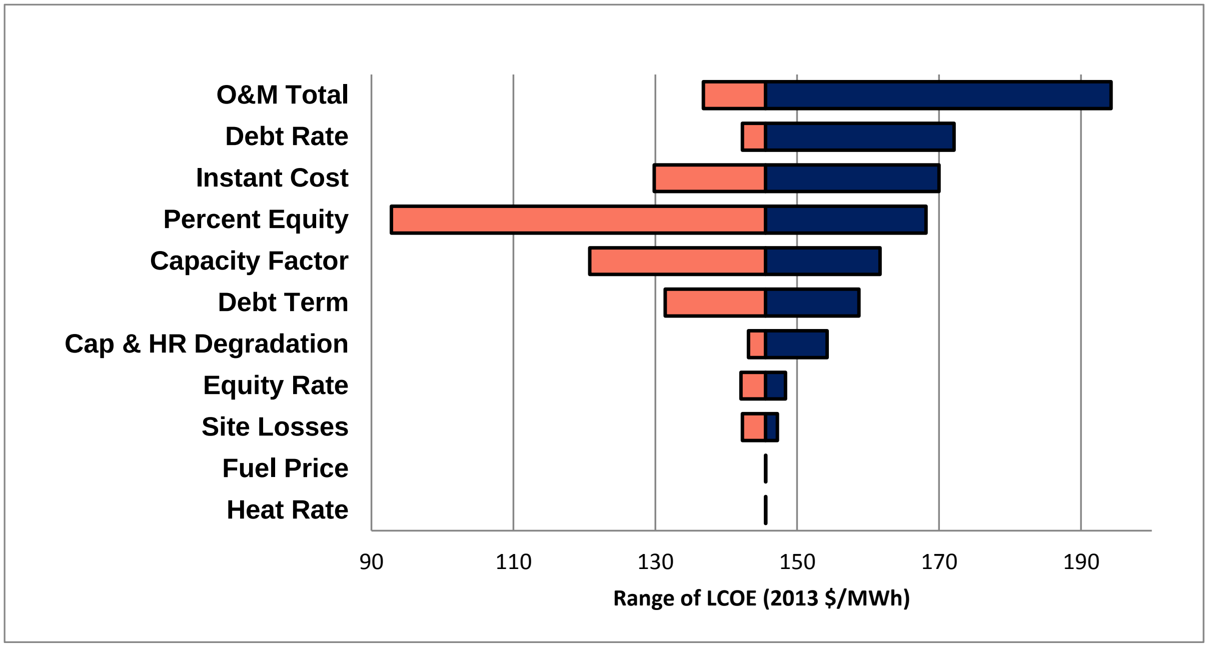
Source: Energy Commission.

Figure C-11: Tornado Diagram—Solar Tower Without Storage 100 MW



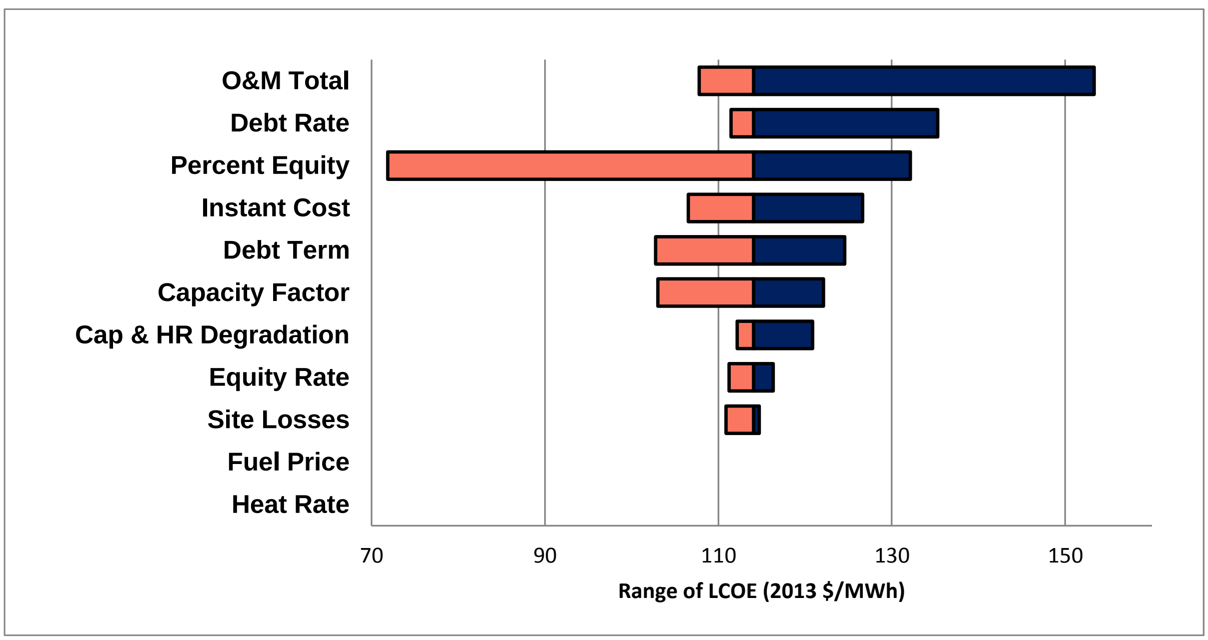
Source: Energy Commission.

Figure C-12: Tornado Diagram—Solar Tower Six Hours Storage 100 MW



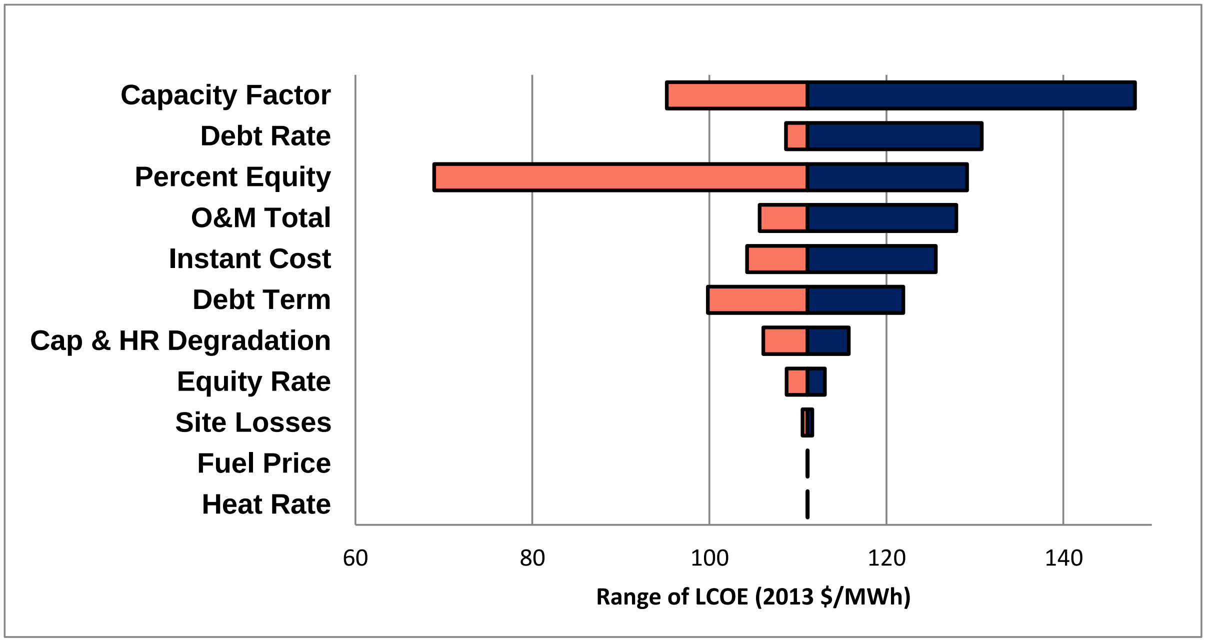
Source: Energy Commission.

Figure C-13: Tornado Diagram—Solar Tower 11 Hours Storage 100 MW



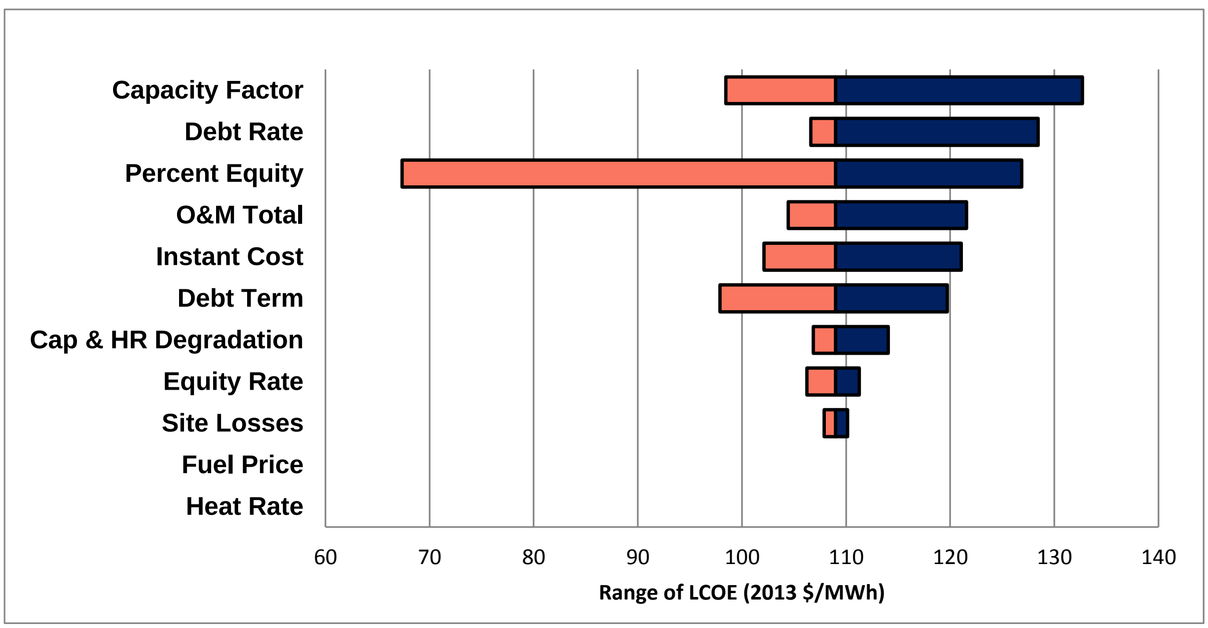
Source: Energy Commission.

Figure C-14: Tornado Diagram—Solar Photovoltaic Thin-Film 100 MW



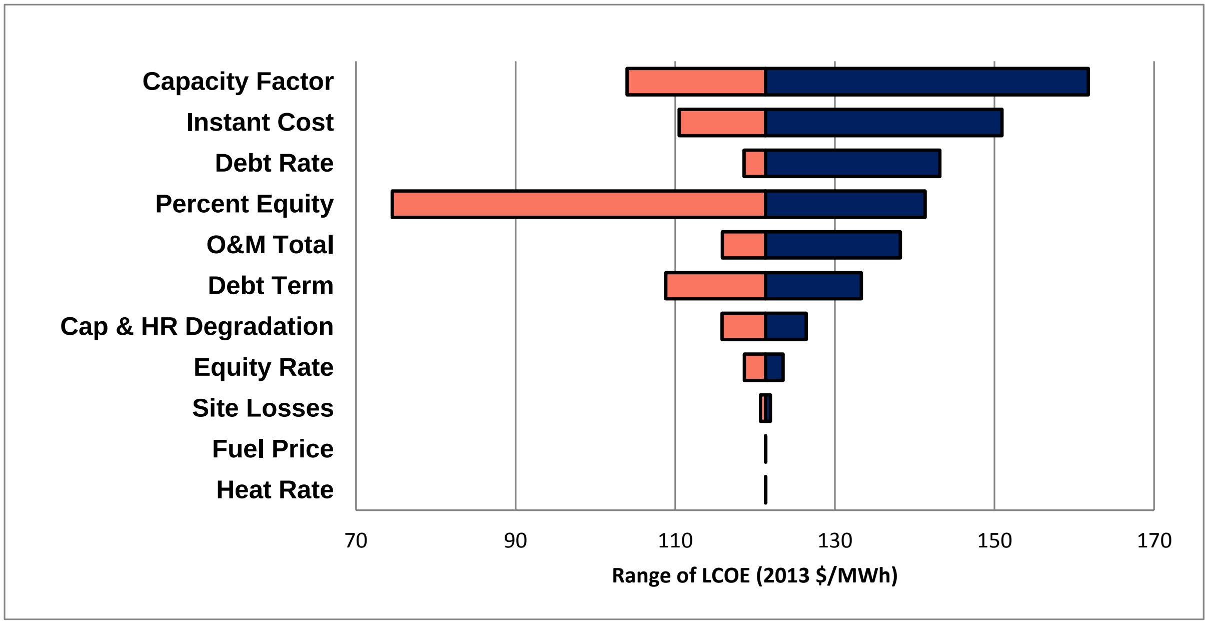
Source: Energy Commission.

Figure C-15: Tornado Diagram—Solar Photovoltaic Single Axis 100 MW



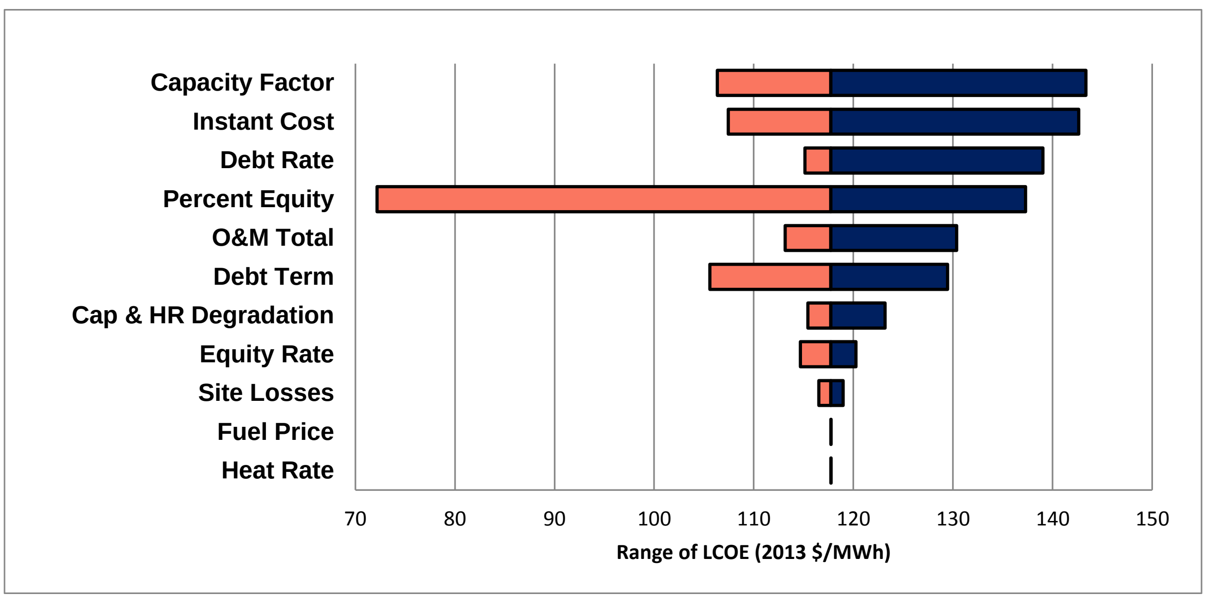
Source: Energy Commission.

Figure C-16: Tornado Diagram—Solar Photovoltaic Thin-Film 20 MW



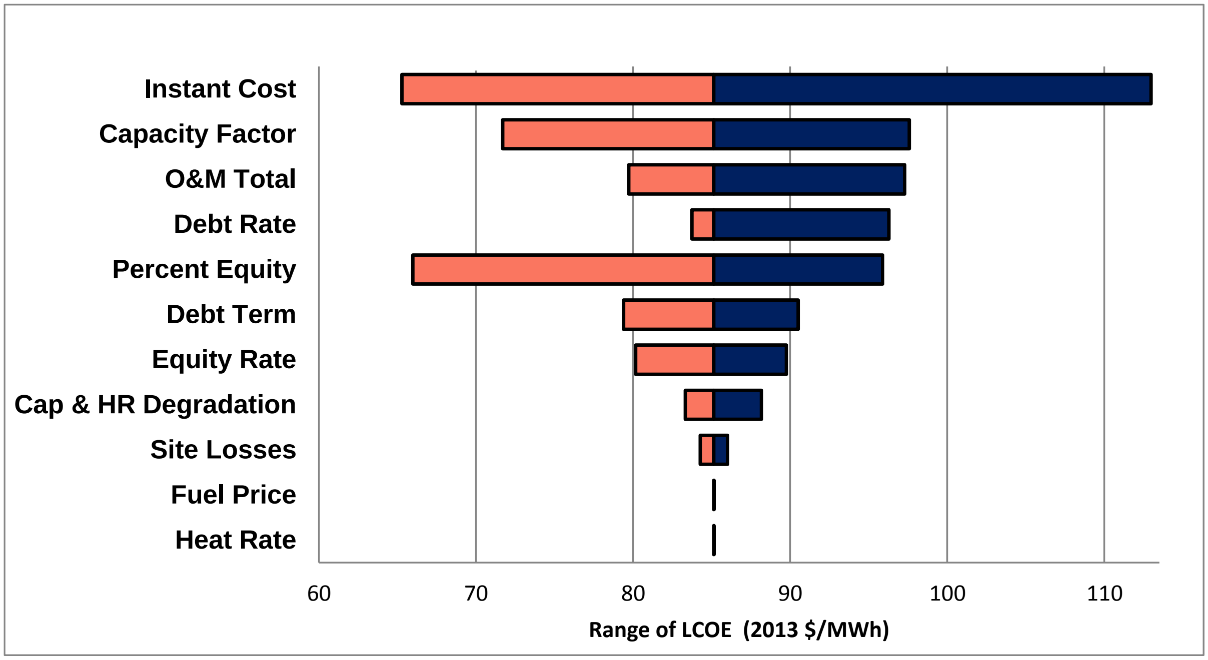
Source: Energy Commission.

Figure C-17: Tornado Diagram—Solar Photovoltaic Single Axis 20 MW



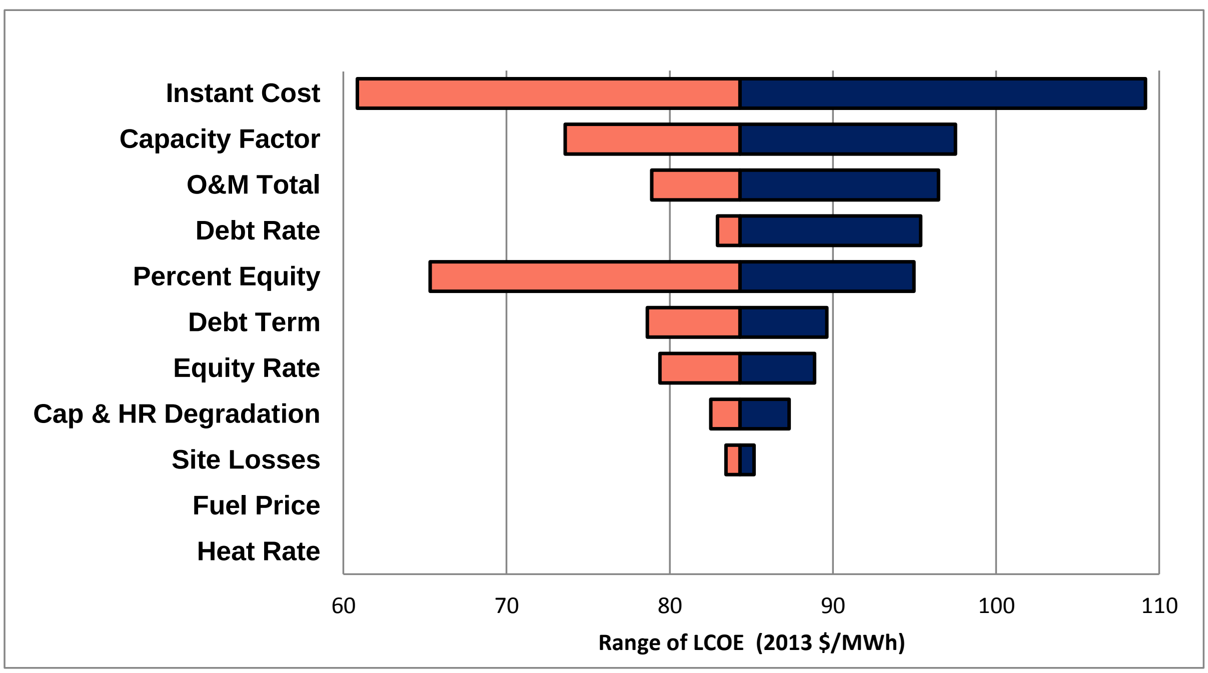
Source: Energy Commission.

Figure C-18: Tornado Diagram—Wind—Class 3 100 MW



Source: Energy Commission.

Figure C-19: Tornado Diagram—Wind—Class 4 100 MW



Source: Energy Commission.

APPENDIX D: Description of Models

Three models were used to calculate the instant, installed, and levelized costs in this report:

- The Energy Commission's COG Model
- Lumina's Analytica Model
- Analytica ACAT

Cost of Generation Model

The COG Model is used to develop three values used in the report:

- Instant Cost
- Installed Cost
- Levelized Cost

The first two costs are developed as a part of the logic that develops levelized cost.

Instant Cost

The capital cost component of instant cost is entered into the COG Model based on exogenously calculated values. It can be a single value reflecting the base year costs—this is presently 2011. Or it can be entered as a formula to capture the changing costs over the study period—most commonly for renewables such as solar that are, in general, expected to have declining costs.

The COG Model will then add ancillary costs as necessary, such as land costs, interconnection costs, and licensing costs, to get the complete instant cost. These costs are shown on the construction costs worksheet and brought forward to the input-output worksheet.

Installed Cost

Installed costs are then developed from the instant costs in the same construction costs worksheet by adding the cost of the construction loan insurance and loan fees.

Levelized Cost

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

Using the inputs on the left side of the flow chart, which is described in detail later in this appendix, the COG 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
    - Capital and Financing (including licensing costs)
    - Ad Valorem
    - Insurance
    - Fixed O&M
- Levelized variable costs
    - Fuel and Emission Costs
    - Variable O&M
- Total levelized costs (Fixed + Variable)

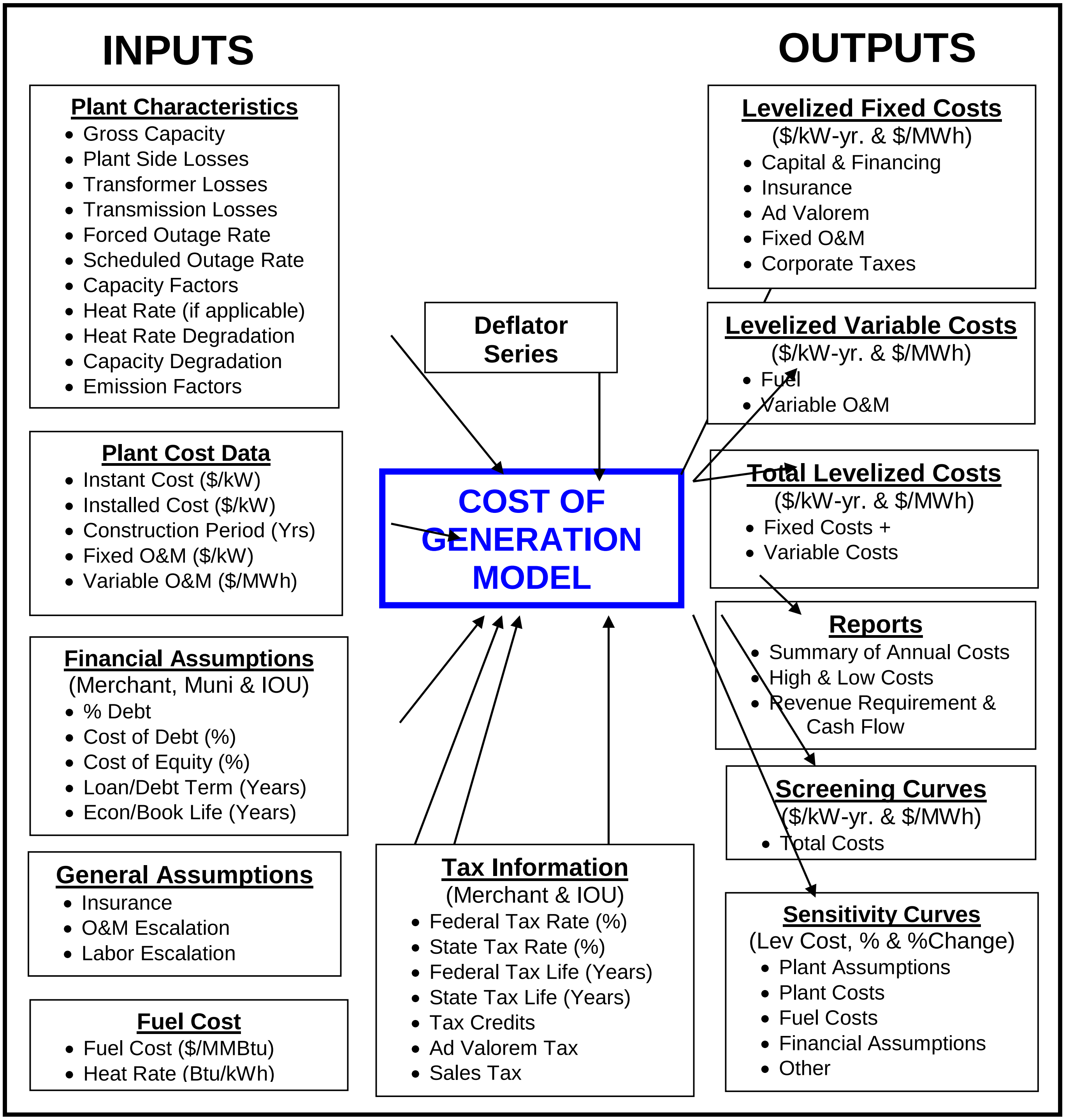
These categories are typical of most cost of generation models. These results and supporting data are used in almost any study that involves the cost of generation technologies. They can be used to evaluate the cost of a generation technology as part of a feasibility study or to compare the differences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

This COG Model is more useful than the typical model since it also provides high and low levelized costs. It also differs from 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 COG 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 COG Model can also be used to forecast the cost of wholesale electricity.

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



Source: Energy Commission.

Cost of Generation Model Structure

The COG Model is contained in an Excel workbook (spreadsheet model) that presently calculates levelized costs for 19 technologies but is designed to accommodate an almost unlimited number of additional technologies. It also includes a function for storing and recalling user-defined scenarios. This workbook consists of 30 spreadsheets (worksheets), but 2 of these are informational and do not contribute to the calculations. A summary of these worksheets is illustrated in **Figure D-2**. A flow sheet description of the COG Model can be found on the instructions worksheet of the COG Model.

One way to better understand the COG 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 that also provide preprocessing, as necessary.

Input-Output Worksheet

The input-output worksheet is where the user selects the generation technology, the type of financing, and the start year, and reads the results. **Figure D-3** shows the input selection box. Through the use of drop-down windows, the user selects the type of financing, start year of the project, the technology, and tax loss treatment. For a gas-fired technology the user also selects carbon price, gas price, and region. Once all of these selections have been made, the user presses the red execute button to activate the levelized cost macro.

Based on these selections, the macro collects the relevant data 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 **Table D-1**. The reported high-cost and low-cost LCOEs assume that all high or low assumptions occur simultaneously. This deterministic case would occur with such small probabilities that they are useful only for perspective—which explains why staff has gone to probabilistic LCOEs derived from ACAT.

Table D-2 shows the associated data assumptions that have been used. These high and low assumptions are useful from any perspective, deterministic or probabilistic. They are important to the user and should be scrutinized to make sure that they are consistent with the project for which they are being used. At the bottom of these data, there is a DSCR check to ensure that financing is realistic.

Figure D-2: Summary of Worksheets

Instructions	General Instructions & Model Description
Input-Output	User selects Assumptions - Levelized Costs are reported along with some key data values.
Annual Cost Chart	Reports annual fixed, variable and total O&M costs for selected scenario as well as the NPV for each cost stream
Screening Curve	Contains a GUI and macro that graphs the levelized cost as a function of capacity factor for any of the plant technologies.
Sensitivity Curve	Contains a GUI and macro that graph the levelized cost as a function of a percent change in various base values so as to examine the sensitivity of the output to the specified variables.
Print Tables	Presents and compares costs for all technologies and developers for up to two scenarios
Yearly Costs	User selects technologies, developers and cost cases and annual costs are presented for each selection
Changes	Tracks model modifications using version numbers
Physical Data	Plant physical data is summarized - User can override data for unique scenarios.
Financial Data	Financial & tax data are summarized - User can override data for unique scenarios
Construction Costs	Construction costs are calculated in base year dollars
O&M Costs	O&M Costs are calculated in base year dollars
Income Cash -Flow	Calculates annual costs and levelizes those costs – using cash-flow accounting
Income Rev Req	Calculates annual costs and levelizes those costs – using revenue requirement accounting
Inflation	Calculates historical & forward inflation rates based on GDP Price Deflator Series - used by income worksheets.
Financial Assumptions	Data assumptions summary of all financial data.
Renewables	Equity return calculations for renewables (wind and nonwind)
Tax Incentives	Presents information on tax incentives by technology
Transmission	Reports transmission line losses and rates
Fuel Price Forecasts	Fuel price forecast - used by the income worksheets.
Air & Water Data	Regional air emissions & water costs - used by Data 2 Worksheet.
ERC Forecasts	General assumptions summary such as inflation rates & tax rates.
SCAQMD Fees	Presents SCAQMD Rule 1304.1 In-lieu ERC Fees
Plant Type Assumptions	Summary of data assumptions summary for each plant type.
PTA - Average	Average plant type assumptions
PTA - High	High plant type assumptions
PTA - Low	Low plant type assumptions
General Assumptions	General assumptions summary such as inflation rates & tax rates.
Labor Table	Calculates the labor cost components.
Overhaul Calcs	Calculates overhaul & equipment replacement costs - used by Data 2 Worksheet.
CC HeatRate	Shows the regression and provides the heat rate factors.
WEP Forecast	Contains wholesale electricity price forecast

Source: Energy Commission.

Figure D-3: Technology Assumptions Selection Box

INPUT SELECTION	
Step 1: Select Developer and Financing	Merchant Fossil
Step 2: Select Start-Year	2013
Step 3: Select Technology	Combined Cycle - 2 CTs No Duct Firing 500 MW
Step 4: Select Tax Loss Treatment	Tax Equity Financing
FOR GAS-FIRED UNITS ONLY	
Step 5: Select Carbon Price	Carbon Price Mid
Step 6: Select Natural Gas Price	CA Average
Step 7: Select Plant Site Region	CA - Avg.
Step 8: Turbine Configuration	2
Step 9: Click the Execute Button	Execute

Source: Energy Commission.

Table D-1: Illustrative Levelized Cost Output

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

Source: Energy Commission.

Table D-2: Illustrative Data Assumptions

DATA ASSUMPTIONS ASSOCIATED WITH YOUR INPUT SELECTION

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

Merchant Fossil	Mid Case		High Case		Low Case	
Debt Service Coverage Ratios - Average	***1.52***		***2.61***		***1.37***	
Debt Service Coverage Ratios - Minimum	***1.42***		***2.48***		***1.27***	

Source: Energy Commission.

Other COG Model Features

Besides the LCOE described in **Table D-1**, the COG Model has two other functions:

- Screening Curves—Plots LCOE as a function of capacity factor.
- Sensitivity Curves—While the screening curve function addresses only the effect of capacity factor, the screening curve function addresses a wide range of variables.

Lumina's Analytica Model

Analytica is a visual software package developed by Lumina Decision Systems for creating, analyzing, and communicating quantitative decision models (Lumina, 2013). As a modeling environment, it is interesting in the way it combines hierarchical influence diagrams for visual creation and view of models, intelligent arrays for working with multidimensional data, Monte Carlo simulation for analyzing risk and uncertainty, and optimization, including linear and nonlinear programming. The design, especially the influence diagrams and treatment of uncertainty, is based on ideas from the field of decision analysis. As a computer language, it is notable in combining a declarative (nonprocedural) structure for referential transparency, array abstraction, and automatic dependency maintenance for efficient sequencing of computation.

The Analytica Cost of Generation Analysis Tool

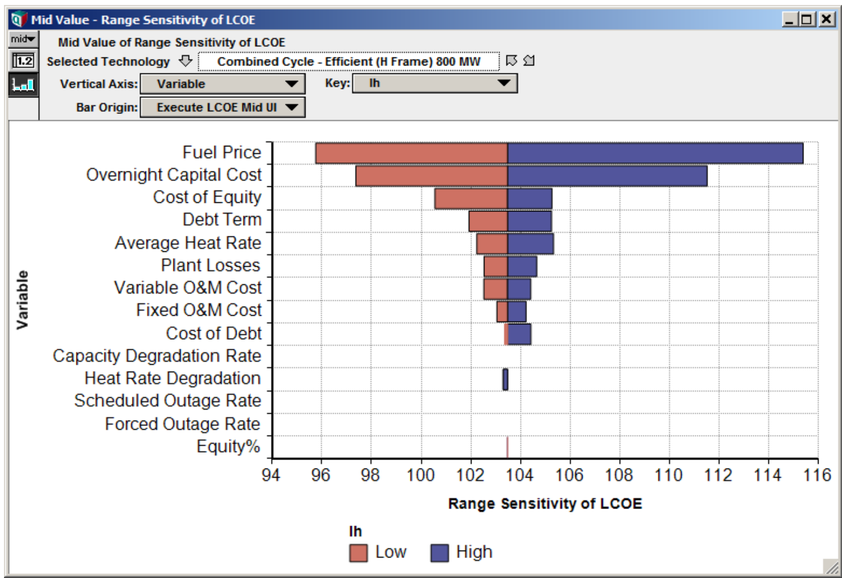
The ***ACAT*** (Sherwin and Henrion, 2013) combines the Analytica Model with the COG Model to provide probabilistic high and low LCOEs, using Monte Carlo analysis. ACAT does this by changing input cells in the COG spreadsheet to vary key input assumptions and saving the corresponding results. ACAT can perform such sensitivity analysis or Monte Carlo analysis for one, all, or a selected subset of the electricity generation technologies represented in COG.

For range sensitivity analysis, it varies each parameter from its specified low to high value while keeping the values of all the other input parameters at their mid values. It uses COG to calculate the corresponding result (LCOE) for each technology. In this way, it lets one compare the direction and magnitude of the change in the output caused the change in each input. **Figure D-4** illustrates the ACAT tornado diagram that displays the resulting range sensitivities for each parameter arranged one above the other.

For Monte Carlo analysis, ACAT fits a probability distribution to each uncertain input parameter, treating the specified low, mid, and high values as 10th, 50th, and 90th percentiles, as illustrated in **Figure D-5.** It extrapolates a minimum (0th percentile) and maximum (100th percentile) to enclose the specified low to high values, subject to specified bounds on each quantity. For example, most parameters are bounded below by zero. It then fits cubic spline distributions (see below) to the specified percentiles. ACAT then performs

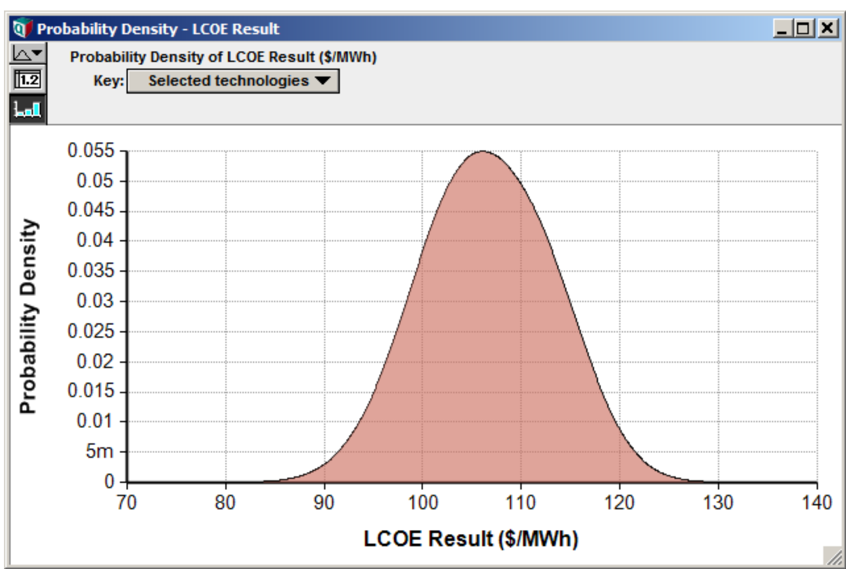
Monte Carlo by selecting values at random from each parameter distribution and setting those as inputs into COG. It obtains and stores the corresponding result for LCOE. It repeats this process a specified number of times, usually between 100 to 10,000, to generate a random sample of values from the output distribution. It then lets one display the resulting distribution as a probability density function, cumulative distribution function, or other forms.

Figure D-4: An Example Range Sensitivity Analysis (Tornado Chart) Generated by ACAT



Source: Energy Commission.

Figure D-5: An Example Probability Distribution Generated by ACAT



Source: Energy Commission.

Cubic Spline Distributions

ACAT lets you fit a uniform, triangular, or cubic spline distribution to the specified low, mid, and high values of each uncertain quantity. For this purpose, the cubic spline distribution was found to give the best result.

ACAT treats the low, mid, and high values respectively as the 10th, 50th, and 90th percentiles of the distribution (also x10, x50, and x90). By default it estimates lower and upper bounds, x0 and x100, for each quantity such that:

$$x100 - x90 = w\,(x90 - x50)$$

$$x10 - x0 = w\,(x50 - x10)$$

These calculations use a width factor w set by default to 2.0. ACAT also lets the user specify a minimum and maximum value on the possible values. For most quantities, the minimum is zero. For percentages, the maximum is at most 100 percent. The minimum and maximum override the x0 and x100 respectively if x0<minimum or x100>maximum.

The *cubic spline distribution* fits a piecewise cubic distribution to the five specified percentiles on the cumulative probability distribution. This usually gives rise to a bell-shaped curve as long as the percentiles are spaced apart, but with finite bounds unlike a normal or lognormal distribution.

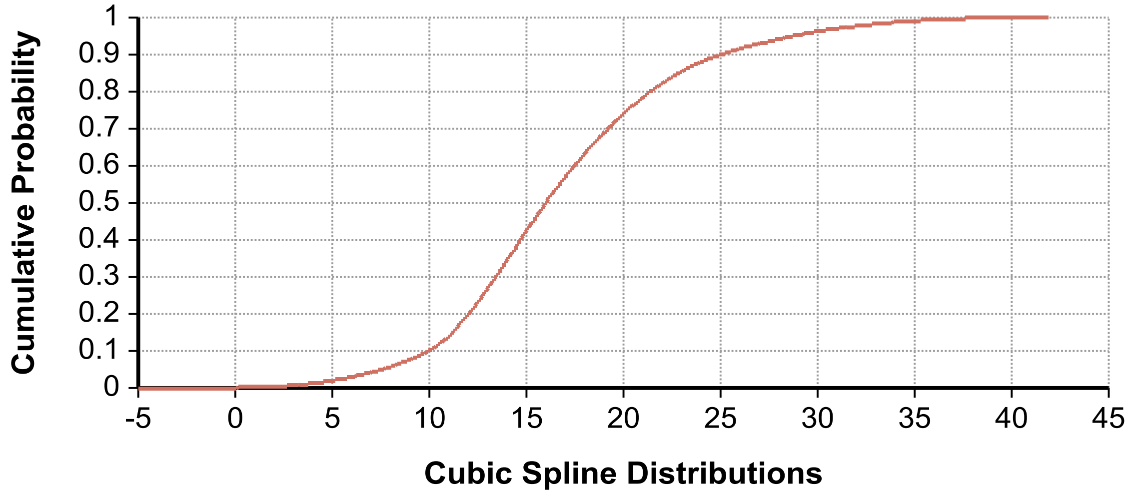
Figure D-6 and **Figure D-7** show an example cubic spline distribution fitted to the five percentiles with probabilities and values given in **Table D-3**. Note that the cumulative probability **Figure D-6** matches all the values in **Table D-3** except the 50 percent value—a good match with smooth looking curve.

Table D-3: Shows the Cumulative Probability and Corresponding Values (Percentiles) for the Specified Min, Low, Mid, High, and Maximum Values

	Probability	Value
Min	0%	0
Low	10%	10
Mid	50%	15
High	90%	25
Max	100%	45

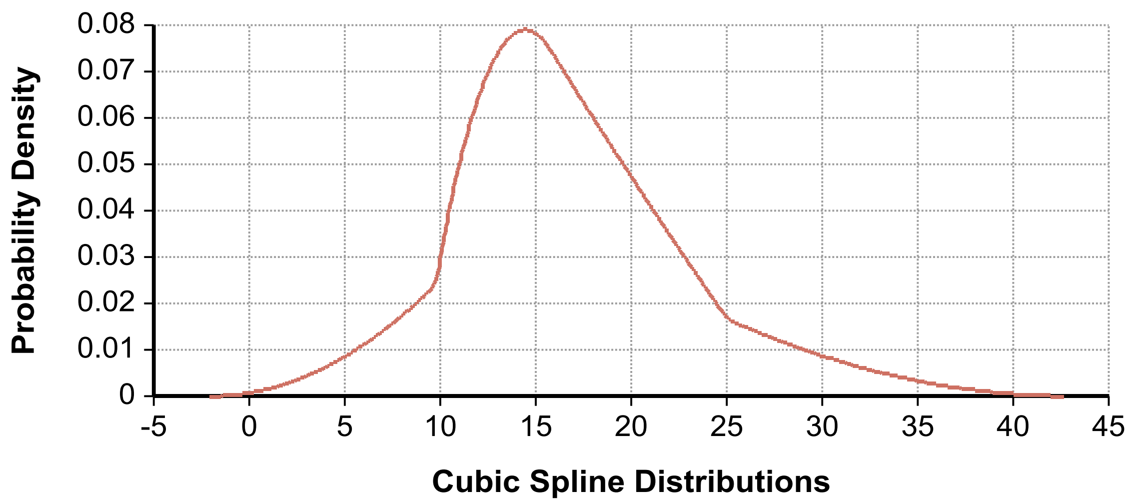
Source: Energy Commission.

Figure D-6: Cubic Spline Distribution Fitted to Points on the Cumulative Probability Distribution With Probabilities and Values Given in Table D-3



Source: Energy Commission.

Figure D-7: Cubic Spline Distribution From Table D-3 Shown as the Corresponding Probability Density Distribution

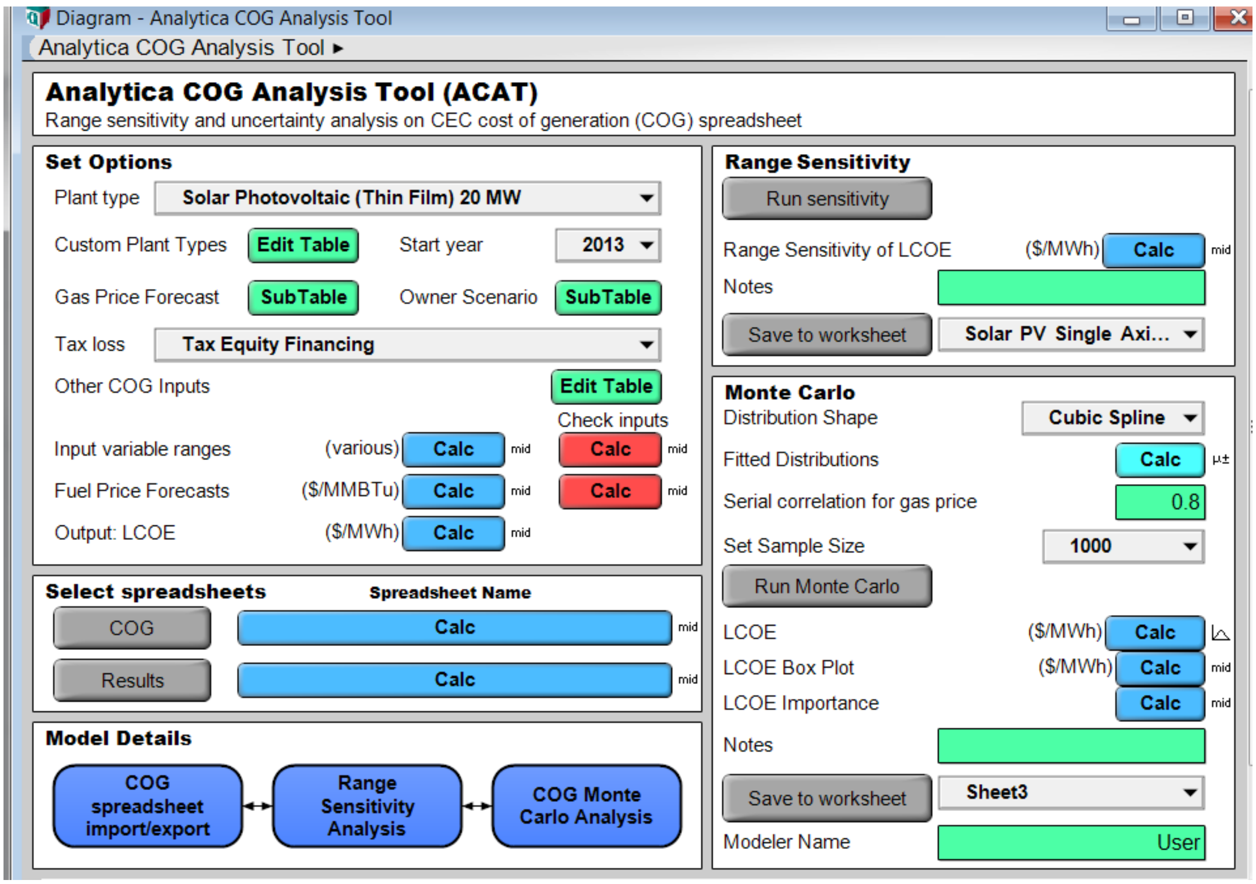


Source: Energy Commission.

If two or more of the percentiles have the same value (for example, if x10 = x50), it has a vertical step in the cumulative distribution and corresponding delta function in the density function. The shape is symmetrical if the specified percentiles are symmetrical. The spline assures a smooth slope on the cumulative distribution but may have a discontinuous slope on the density function.

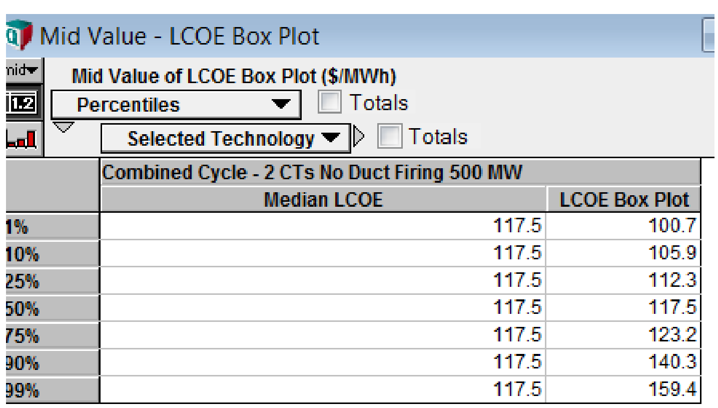
Figure D-8 shows the interface for the ACAT Model. Key features are selecting the plant type, running Monte Carlo, and reading the results from the LCOE box plot, as shown in **Figure D-9.**

Figure D-8: ACAT Interface



Source: Energy Commission.

Figure D-9: ACAT LCOE Box Plot



	Median LCOE	LCOE Box Plot
1%	117.5	100.7
10%	117.5	105.9
25%	117.5	112.3
50%	117.5	117.5
75%	117.5	123.2
90%	117.5	140.3
99%	117.5	159.4

Source: Energy Commission.

APPENDIX E:
Component Levelized Costs

This appendix summarizes component LCOE cost definitions defined in **Figure E-1** for 2013 and 2014.

Table E-1 through **Table E-6** provide a comprehensive summary of component LCOEs in $/MWh and $/kW-Year, for merchant, IOU and POU plants for the start year of 2013.

Table E-7 through **Table E-12** provide the same data for 2024.

Table E-13 and **Table E-14** summarize the total LCOE values for the above 12 tables.

Figure E-1: Definition of LCOE Components

Fixed Costs
Capital and Financing—The total cost of all equipment and construction costs, including financing the plant
Insurance—The cost of insuring the power plant
Ad Valorem—Property taxes
Fixed O&M—Staffing and other costs independent of operating hours
Corporate Taxes—State and federal taxes
Variable Costs
Fuel Cost—The cost of the fuel used
GHG Cost—Cap-and-trade allowance costs
Variable O&M—Operation and maintenance costs that are a function of operating hours
Total Costs
Total Cost = Fixed plus Variable Costs at the point of interconnection with the existing transmission system

Source: Energy Commission

Table E-1: Mid Case Component LCOEs for Merchant Plants (Nominal $/MWh)—Start-Year=2013

		$/MWh (Nominal 2013$)									
Start-Year = 2013 (Nominal $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE At Interconnection Point**
Generation Turbine 49.9 MW	49.9	325.78	22.33	32.38	85.38	94.28	**560.14**	102.66	0.00	**102.66**	**662.81**
Generation Turbine 100 MW	100	325.73	22.32	32.37	82.78	94.32	**557.52**	102.99	0.00	**102.99**	**660.52**
Generation Turbine - Advanced 200 MW	200	176.79	12.13	17.60	50.52	51.11	**308.15**	95.67	0.00	**95.67**	**403.83**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	24.16	1.63	2.36	9.13	7.98	**45.27**	70.44	0.79	**71.23**	**116.51**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	23.70	1.60	2.32	9.13	7.83	**44.58**	70.44	0.79	**71.23**	**115.81**
Biomass Fluidized Bed Boiler 50 MW	50	62.70	5.34	7.88	19.71	-24.51	**71.12**	44.06	6.86	**50.91**	**122.04**
Geothermal Binary 30 MW	30	89.16	7.64	11.27	17.90	-35.35	**90.63**	0.00	0.00	**0.00**	**90.63**
Geothermal Flash 30 MW	30	104.13	8.92	13.16	19.08	-41.24	**104.05**	8.43	0.00	**8.43**	**112.48**
Solar Parabolic Trough W/O Storage 250 MW	250	172.96	7.63	12.35	44.73	-69.49	**168.18**	0.00	0.00	**0.00**	**168.18**
Solar Parabolic Trough With Storage 250 MW	250	152.44	6.73	1.98	27.57	-61.31	**127.40**	0.00	0.00	**0.00**	**127.40**
Solar Power Tower W/O Storage 100 MW	100	165.05	7.27	11.78	34.61	-66.13	**152.58**	0.00	0.00	**0.00**	**152.58**
Solar Power Tower With Storage 100 MW 6 HRs	100	178.88	7.89	2.32	28.29	-71.86	**145.52**	0.00	0.00	**0.00**	**145.52**
Solar Power Tower With Storage 100 MW 11 HRs	100	142.95	6.31	1.86	20.32	-57.38	**114.06**	0.00	0.00	**0.00**	**114.06**
Solar Photovoltaic (Thin Film) 100 MW	100	143.71	6.38	1.88	17.62	-58.51	**111.07**	0.00	0.00	**0.00**	**111.07**
Solar Photovoltaic (Single Axis) 100 MW	100	141.04	6.22	1.83	16.54	-56.64	**109.00**	0.00	0.00	**0.00**	**109.00**
Solar Photovoltaic (Thin Film) 20 MW	20	159.27	7.06	2.08	17.69	-64.79	**121.31**	0.00	0.00	**0.00**	**121.31**
Solar Photovoltaic (Single Axis) 20 MW	20	154.22	6.80	2.00	16.61	-61.90	**117.74**	0.00	0.00	**0.00**	**117.74**
Wind - Class 3 100 MW	100	80.24	6.85	10.02	0.00	-24.19	**72.92**	0.00	12.20	**12.20**	**85.12**
Wind - Class 4 100 MW	100	79.56	6.80	9.94	0.00	-24.19	**72.10**	0.00	12.20	**12.20**	**84.31**

Source: Energy Commission.

Table E-2: Mid Case Component LCOEs for IOU Plants (Nominal $/MWh)—Start-Year=2013

		$/MWh (Nominal 2013$)									
Start-Year = 2013 (Nominal $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE At Interconnection Point**
Generation Turbine 49.9 MW	49.9	1367.58	63.87	116.88	420.87	146.15	**2115.35**	100.19	0.00	**100.19**	**2215.54**
Generation Turbine 100 MW	100	1367.22	63.85	116.85	408.06	146.26	**2102.25**	100.51	0.00	**100.51**	**2202.75**
Generation Turbine - Advanced 200 MW	200	746.64	34.87	63.81	248.47	79.96	**1173.76**	93.15	0.00	**93.15**	**1266.91**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	20.22	0.94	1.73	9.04	2.83	**34.76**	69.00	0.79	**69.78**	**104.54**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	19.83	0.93	1.70	9.04	2.78	**34.27**	69.00	0.79	**69.78**	**104.05**
Biomass Fluidized Bed Boiler 50 MW	50	66.36	3.10	5.67	19.78	-4.49	**90.41**	44.24	6.88	**51.12**	**141.53**
Geothermal Binary 30 MW	30	96.01	4.48	8.21	17.97	-6.46	**120.21**	0.00	0.00	**0.00**	**120.21**
Geothermal Flash 30 MW	30	111.73	5.22	9.55	19.17	-7.52	**138.15**	8.57	0.00	**8.57**	**146.72**
Solar Parabolic Trough W/O Storage 250 MW	250	189.83	4.43	2.43	44.83	-12.79	**228.73**	0.00	0.00	**0.00**	**228.73**
Solar Parabolic Trough With Storage 250 MW	250	167.42	3.91	1.43	27.63	-11.26	**189.12**	0.00	0.00	**0.00**	**189.12**
Solar Power Tower W/O Storage 100 MW	100	180.99	4.23	2.32	34.68	-12.18	**210.04**	0.00	0.00	**0.00**	**210.04**
Solar Power Tower With Storage 100 MW 6 HRs	100	196.38	4.59	1.68	28.35	-13.20	**217.79**	0.00	0.00	**0.00**	**217.79**
Solar Power Tower With Storage 100 MW 11 HRs	100	156.89	3.66	1.34	20.36	-10.54	**171.72**	0.00	0.00	**0.00**	**171.72**
Solar Photovoltaic (Thin Film) 100 MW	100	157.90	3.69	1.35	17.66	-10.60	**170.00**	0.00	0.00	**0.00**	**170.00**
Solar Photovoltaic (Single Axis) 100 MW	100	154.07	3.60	1.32	16.58	-10.34	**165.22**	0.00	0.00	**0.00**	**165.22**
Solar Photovoltaic (Thin Film) 20 MW	20	174.94	4.09	1.50	17.73	-11.74	**186.51**	0.00	0.00	**0.00**	**186.51**
Solar Photovoltaic (Single Axis) 20 MW	20	168.44	3.93	1.44	16.65	-11.31	**179.16**	0.00	0.00	**0.00**	**179.16**
Wind - Class 3 100 MW	100	84.47	3.95	7.22	0.00	-3.05	**92.58**	0.00	12.16	**12.16**	**104.74**
Wind - Class 4 100 MW	100	83.79	3.91	7.16	0.00	-3.03	**91.84**	0.00	12.16	**12.16**	**103.99**

Source: Energy Commission.

Table E-3: Mid Case Component LCOEs for POU Plants (Nominal $/MWh)—Start-Year=2013

Start-Year = 2013 (Nominal $)	Size MW	$/MWh (Nominal 2013$) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Credits & In-lieu	Fixed Costs	Fuel	Variable O&M	Variable Cost	Total LCOE At Interconnection Point
Generation Turbine 49.9 MW	49.9	110.80	15.47	13.81	59.56	0.00	**199.65**	111.95	0.00	**111.95**	**311.60**
Generation Turbine 100 MW	100	110.77	15.47	13.81	57.75	0.00	**197.80**	112.31	0.00	**112.31**	**310.11**
Generation Turbine - Advanced 200 MW	200	59.89	8.36	7.46	35.33	0.00	**111.05**	104.57	0.00	**104.57**	**215.62**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	12.05	1.68	1.50	9.55	0.00	**24.79**	76.74	0.83	**77.57**	**102.35**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	11.83	1.65	1.47	9.55	0.00	**24.51**	76.74	0.83	**77.57**	**102.08**
Biomass Fluidized Bed Boiler 50 MW	50	38.79	5.42	4.83	20.86	-0.60	**69.30**	47.00	7.24	**54.24**	**123.54**
Geothermal Binary 30 MW	30	52.73	7.36	6.57	19.14	-0.82	**84.98**	0.00	0.00	**0.00**	**84.98**
Geothermal Flash 30 MW	30	62.61	8.74	7.80	20.40	-0.97	**98.59**	10.91	0.00	**10.91**	**109.50**
Solar Parabolic Trough W/O Storage 250 MW	250	112.03	7.82	2.09	47.72	-1.73	**167.93**	0.00	0.00	**0.00**	**167.93**
Solar Parabolic Trough With Storage 250 MW	250	98.80	6.90	1.23	29.41	-1.53	**134.81**	0.00	0.00	**0.00**	**134.81**
Solar Power Tower W/O Storage 100 MW	100	106.81	7.46	2.00	36.92	-1.65	**151.53**	0.00	0.00	**0.00**	**151.53**
Solar Power Tower With Storage 100 MW 6 HRs	100	115.89	8.09	1.44	30.18	-1.79	**153.81**	0.00	0.00	**0.00**	**153.81**
Solar Power Tower With Storage 100 MW 11 HRs	100	92.59	6.47	1.15	21.68	-1.43	**120.45**	0.00	0.00	**0.00**	**120.45**
Solar Photovoltaic (Thin Film) 100 MW	100	95.90	6.70	1.20	19.00	-1.48	**121.30**	0.00	0.00	**0.00**	**121.30**
Solar Photovoltaic (Single Axis) 100 MW	100	92.70	6.47	1.16	17.67	-1.43	**116.57**	0.00	0.00	**0.00**	**116.57**
Solar Photovoltaic (Thin Film) 20 MW	20	106.24	7.42	1.32	19.07	-1.64	**132.42**	0.00	0.00	**0.00**	**132.42**
Solar Photovoltaic (Single Axis) 20 MW	20	101.35	7.08	1.26	17.74	-1.57	**125.86**	0.00	0.00	**0.00**	**125.86**
Wind - Class 3 100 MW	100	50.46	7.05	6.29	0.00	-0.78	**63.01**	0.00	12.79	**12.79**	**75.80**
Wind - Class 4 100 MW	100	50.05	6.99	6.24	0.00	-0.77	**62.50**	0.00	12.79	**12.79**	**75.29**

Source: Energy Commission.

Table E-4: Mid Case Component LCOEs for Merchant Plants (Nominal $/kW-Year)—Start-Year=2013

Start-Year = 2013 (Nominal $)	Size MW	$/kW-Year (Nominal 2013$) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	Fixed Costs	Fuel	Variable O&M	Variable Cost	Total LCOE At Interconnection Point
Generation Turbine 49.9 MW	49.9	135.49	9.29	13.47	35.51	39.21	**232.96**	42.70	0.00	**42.70**	**275.66**
Generation Turbine 100 MW	100	135.04	9.25	13.42	34.32	39.10	**231.14**	42.70	0.00	**42.70**	**273.83**
Generation Turbine - Advanced 200 MW	200	110.47	7.58	10.99	31.57	31.94	**192.55**	59.78	0.00	**59.78**	**252.33**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	114.37	7.72	11.19	43.23	37.77	**214.28**	333.39	3.75	**337.14**	**551.42**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	112.18	7.57	10.98	43.23	37.04	**211.00**	333.39	3.75	**337.14**	**548.14**
Biomass Fluidized Bed Boiler 50 MW	50	417.37	35.58	52.48	131.18	-163.18	**473.43**	293.28	45.64	**338.92**	**812.34**
Geothermal Binary 30 MW	30	552.25	47.33	69.82	110.86	-218.94	**561.31**	0.00	0.00	**0.00**	**561.31**
Geothermal Flash 30 MW	30	604.85	51.82	76.44	110.86	-239.56	**604.41**	48.95	0.00	**48.95**	**653.36**
Solar Parabolic Trough W/O Storage 250 MW	250	339.28	14.97	24.23	87.75	-136.31	**329.92**	0.00	0.00	**0.00**	**329.92**
Solar Parabolic Trough With Storage 250 MW	250	485.22	21.42	6.30	87.75	-195.17	**405.52**	0.00	0.00	**0.00**	**405.52**
Solar Power Tower W/O Storage 100 MW	100	370.46	16.33	26.43	77.68	-148.43	**342.48**	0.00	0.00	**0.00**	**342.48**
Solar Power Tower With Storage 100 MW 6 HRs	100	518.08	22.86	6.73	81.93	-208.13	**421.46**	0.00	0.00	**0.00**	**421.46**
Solar Power Tower With Storage 100 MW 11 HRs	100	576.35	25.42	7.48	81.93	-231.33	**459.85**	0.00	0.00	**0.00**	**459.85**
Solar Photovoltaic (Thin Film) 100 MW	100	266.68	11.83	3.48	32.69	-108.58	**206.11**	0.00	0.00	**0.00**	**206.11**
Solar Photovoltaic (Single Axis) 100 MW	100	312.12	13.77	4.05	36.61	-125.34	**241.22**	0.00	0.00	**0.00**	**241.22**
Solar Photovoltaic (Thin Film) 20 MW	20	294.37	13.05	3.84	32.69	-119.74	**224.21**	0.00	0.00	**0.00**	**224.21**
Solar Photovoltaic (Single Axis) 20 MW	20	339.93	14.99	4.41	36.61	-136.43	**259.52**	0.00	0.00	**0.00**	**259.52**
Wind - Class 3 100 MW	100	171.31	14.64	21.39	0.00	-51.65	**155.69**	0.00	26.05	**26.05**	**181.75**
Wind - Class 4 100 MW	100	163.34	13.96	20.40	0.00	-49.67	**148.03**	0.00	25.05	**25.05**	**173.08**

Source: Energy Commission.

Table E-5: Mid Case Component LCOEs for IOU Plants (Nominal $/kW-Year)—Start-Year=2013

		$/kW-Year (Nominal 2013$)									
Start-Year = 2013 (Nominal $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel	Variable O&M	**Variabl e Cost**	**Total LCOE At Interconnec tion Point**
Generation Turbine 49.9 MW	49.9	114.27	5.34	9.77	35.17	12.21	**176.76**	8.37	0.00	**8.37**	**185.13**
Generation Turbine 100 MW	100	113.88	5.32	9.73	33.99	12.18	**175.10**	8.37	0.00	**8.37**	**183.47**
Generation Turbine - Advanced 200 MW	200	93.95	4.39	8.03	31.26	10.06	**147.69**	11.72	0.00	**11.72**	**159.41**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	95.78	4.47	8.19	42.82	13.40	**164.66**	326.83	3.72	**330.54**	**495.20**
Combined Cycle - 2 CTs With Duct Firing 550 MV	550	93.94	4.39	8.03	42.82	13.14	**162.32**	326.83	3.72	**330.54**	**492.86**
Biomass Fluidized Bed Boiler 50 MW	50	441.65	20.63	37.75	131.63	-29.90	**601.75**	294.44	45.79	**340.23**	**941.97**
Geothermal Binary 30 MW	30	594.18	27.75	50.78	111.24	-39.99	**743.97**	0.00	0.00	**0.00**	**743.97**
Geothermal Flash 30 MW	30	648.52	30.29	55.43	111.24	-43.62	**801.85**	49.77	0.00	**49.77**	**851.61**
Solar Parabolic Trough W/O Storage 250 MW	250	372.24	8.69	4.77	87.90	-25.09	**448.52**	0.00	0.00	**0.00**	**448.52**
Solar Parabolic Trough With Storage 250 MW	250	532.69	12.44	4.55	87.90	-35.83	**601.76**	0.00	0.00	**0.00**	**601.76**
Solar Power Tower W/O Storage 100 MW	100	406.09	9.48	5.21	77.81	-27.33	**471.26**	0.00	0.00	**0.00**	**471.26**
Solar Power Tower With Storage 100 MW 6 HRs	100	568.53	13.28	4.86	82.07	-38.21	**630.53**	0.00	0.00	**0.00**	**630.53**
Solar Power Tower With Storage 100 MW 11 HR	100	632.28	14.76	5.40	82.07	-42.48	**692.04**	0.00	0.00	**0.00**	**692.04**
Solar Photovoltaic (Thin Film) 100 MW	100	292.80	6.84	2.50	32.74	-19.66	**315.22**	0.00	0.00	**0.00**	**315.22**
Solar Photovoltaic (Single Axis) 100 MW	100	340.82	7.96	2.91	36.67	-22.88	**365.48**	0.00	0.00	**0.00**	**365.48**
Solar Photovoltaic (Thin Film) 20 MW	20	323.10	7.54	2.76	32.74	-21.69	**344.46**	0.00	0.00	**0.00**	**344.46**
Solar Photovoltaic (Single Axis) 20 MW	20	371.11	8.67	3.17	36.67	-24.91	**394.71**	0.00	0.00	**0.00**	**394.71**
Wind - Class 3 100 MW	100	180.45	8.43	15.42	0.00	-6.52	**197.78**	0.00	25.97	**25.97**	**223.75**
Wind - Class 4 100 MW	100	172.11	8.04	14.71	0.00	-6.22	**188.64**	0.00	24.97	**24.97**	**213.61**

Source: Energy Commission.

Table E-6: Mid Case Component LCOEs for POU Plants (Nominal $/kW-Year)—Start-Year=2013

		$/kW-Year (Nominal 2013$)									
Start-Year = 2013 (Nominal $)	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Credits & In-lieu	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE At Interconnection Point**
Generation Turbine 49.9 MW	49.9	68.66	9.59	8.56	37.00	0.00	**123.81**	69.54	0.00	**69.54**	**193.34**
Generation Turbine 100 MW	100	68.43	9.56	8.53	35.76	0.00	**122.27**	69.54	0.00	**69.54**	**191.81**
Generation Turbine - Advanced 200 MW	200	55.70	7.78	6.94	32.89	0.00	**103.31**	97.36	0.00	**97.36**	**200.67**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	56.73	7.92	7.07	45.05	0.00	**116.77**	361.97	3.90	**365.87**	**482.63**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	55.69	7.78	6.94	45.05	0.00	**115.45**	361.97	3.90	**365.87**	**481.32**
Biomass Fluidized Bed Boiler 50 MW	50	257.37	35.95	32.08	138.49	-3.98	**459.90**	312.09	48.05	**360.13**	**820.03**
Geothermal Binary 30 MW	30	322.47	45.04	40.19	117.03	-4.99	**519.74**	0.00	0.00	**0.00**	**519.74**
Geothermal Flash 30 MW	30	358.98	50.14	44.74	117.03	-5.55	**565.33**	62.58	0.00	**62.58**	**627.91**
Solar Parabolic Trough W/O Storage 250 MW	250	217.09	15.16	4.06	92.48	-3.36	**325.42**	0.00	0.00	**0.00**	**325.42**
Solar Parabolic Trough With Storage 250 MW	250	310.67	21.69	3.87	92.48	-4.80	**423.90**	0.00	0.00	**0.00**	**423.90**
Solar Power Tower W/O Storage 100 MW	100	236.83	16.54	4.43	81.86	-3.66	**336.00**	0.00	0.00	**0.00**	**336.00**
Solar Power Tower With Storage 100 MW 6 HRs	100	331.57	23.15	4.13	86.34	-5.13	**440.07**	0.00	0.00	**0.00**	**440.07**
Solar Power Tower With Storage 100 MW 11 HRs	100	368.75	25.75	4.60	86.34	-5.70	**479.73**	0.00	0.00	**0.00**	**479.73**
Solar Photovoltaic (Thin Film) 100 MW	100	173.90	12.14	2.17	34.45	-2.69	**219.97**	0.00	0.00	**0.00**	**219.97**
Solar Photovoltaic (Single Axis) 100 MW	100	202.41	14.14	2.52	38.58	-3.13	**254.52**	0.00	0.00	**0.00**	**254.52**
Solar Photovoltaic (Thin Film) 20 MW	20	191.89	13.40	2.39	34.45	-2.97	**239.16**	0.00	0.00	**0.00**	**239.16**
Solar Photovoltaic (Single Axis) 20 MW	20	220.41	15.39	2.75	38.58	-3.41	**273.72**	0.00	0.00	**0.00**	**273.72**
Wind - Class 3 100 MW	100	107.02	14.95	13.34	0.00	-1.66	**133.65**	0.00	27.12	**27.12**	**160.77**
Wind - Class 4 100 MW	100	102.07	14.26	12.72	0.00	-1.58	**127.47**	0.00	26.07	**26.07**	**153.55**

Source: Energy Commission.

Table E-7: Mid Case Component LCOEs for Merchant Plants (Nominal $/MWh)—Start-Year=2024

Start-Year = 2024	Size MW	$/MWh (Nominal 2024$) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE at Interconnection Point**
Generation Turbine 49.9 MW	49.9	424.82	28.96	42.25	107.35	122.84	**726.22**	158.02	0.00	**158.02**	**884.24**
Generation Turbine 100 MW	100	424.87	28.96	42.25	104.08	122.93	**723.10**	158.53	0.00	**158.53**	**881.62**
Generation Turbine - Advanced 200 MW	200	221.32	15.11	22.04	63.52	63.92	**385.91**	147.26	0.00	**147.26**	**533.17**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	31.14	2.09	3.05	11.48	10.28	**58.04**	108.42	1.00	**109.42**	**167.46**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	30.82	2.07	3.02	11.48	10.17	**57.56**	108.42	1.00	**109.42**	**166.97**
Biomass Fludized Bed Boiler 50 MW	50	77.40	6.56	9.73	24.78	-30.28	**88.20**	57.06	8.62	**65.69**	**153.89**
Geothermal Binary 30 MW	30	106.98	9.12	13.53	22.51	-42.46	**109.68**	0.00	0.00	**0.00**	**109.68**
Geothermal Flash 30 MW	30	126.31	10.77	15.97	24.00	-50.08	**126.96**	17.07	0.00	**17.07**	**144.03**
Solar Parabolic Trough W/O Storage 250 MW	250	151.96	6.67	10.87	47.87	-61.26	**156.10**	0.00	0.00	**0.00**	**156.10**
Solar Parabolic Trough With Storage 250 MW	250	133.70	5.87	1.74	29.50	-53.92	**116.90**	0.00	0.00	**0.00**	**116.90**
Solar Power Tower W/O Storage 100 MW	100	145.07	6.36	10.35	30.01	-58.16	**133.63**	0.00	0.00	**0.00**	**133.63**
Solar Power Tower With Storage 100 MW 6 HRs	100	156.86	6.89	2.04	30.15	-63.16	**132.78**	0.00	0.00	**0.00**	**132.78**
Solar Power Tower With Storage 100 MW 11 HRs	100	125.10	5.49	1.63	21.66	-50.33	**103.56**	0.00	0.00	**0.00**	**103.56**
Solar Photovoltaic (Thin Film) 100 MW	100	91.15	4.03	1.19	22.15	-37.46	**81.07**	0.00	0.00	**0.00**	**81.07**
Solar Photovoltaic (Single Axis) 100 MW	100	118.80	5.22	1.54	20.81	-47.88	**98.49**	0.00	0.00	**0.00**	**98.49**
Solar Photovoltaic (Thin Film) 20 MW	20	109.44	4.84	1.43	22.24	-44.85	**93.11**	0.00	0.00	**0.00**	**93.11**
Solar Photovoltaic (Single Axis) 20 MW	20	134.38	5.90	1.75	20.89	-54.11	**108.81**	0.00	0.00	**0.00**	**108.81**
Wind - Class 3 100 MW	100	66.03	5.61	8.31	0.00	-20.22	**59.74**	0.00	15.27	**15.27**	**75.01**
Wind - Class 4 100 MW	100	66.87	5.69	8.41	0.00	-20.47	**60.50**	0.00	15.27	**15.27**	**75.77**

Source: Energy Commission.

Table E-8: Mid Case Component LCOEs for IOU Plants (Nominal $/MWh)—Start-Year=2024

		$/MWh (Nominal 2024$)									
Start-Year = 2024	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE at Interconnection Point**
Generation Turbine 49.9 MW	49.9	1785.36	83.38	152.59	529.26	190.87	**2741.47**	154.44	0.00	**154.44**	**2895.90**
Generation Turbine 100 MW	100	1785.41	83.38	152.59	513.16	191.06	**2725.60**	154.93	0.00	**154.93**	**2880.53**
Generation Turbine - Advanced 200 MW	200	935.74	43.70	79.98	312.47	100.21	**1472.09**	143.59	0.00	**143.59**	**1615.68**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	26.07	1.22	2.23	11.37	3.65	**44.54**	106.36	0.99	**107.35**	**151.88**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	25.80	1.21	2.21	11.37	3.61	**44.19**	106.36	0.99	**107.35**	**151.54**
Biomass Fludized Bed Boiler 50 MW	50	81.94	3.83	7.00	24.87	-5.55	**112.09**	57.32	8.65	**65.97**	**178.06**
Geothermal Binary 30 MW	30	115.23	5.38	9.85	22.60	-7.76	**145.31**	0.00	0.00	**0.00**	**145.31**
Geothermal Flash 30 MW	30	135.59	6.33	11.59	24.10	-9.12	**168.49**	17.36	0.00	**17.36**	**185.85**
Solar Parabolic Trough W/O Storage 250 MW	250	166.99	3.90	2.14	47.96	-11.27	**209.72**	0.00	0.00	**0.00**	**209.72**
Solar Parabolic Trough With Storage 250 MW	250	146.98	3.43	1.26	29.56	-9.90	**171.34**	0.00	0.00	**0.00**	**171.34**
Solar Power Tower W/O Storage 100 MW	100	159.13	3.72	2.04	30.07	-10.71	**184.24**	0.00	0.00	**0.00**	**184.24**
Solar Power Tower With Storage 100 MW 6 HRs	100	172.35	4.02	1.47	30.22	-11.59	**196.47**	0.00	0.00	**0.00**	**196.47**
Solar Power Tower With Storage 100 MW 11 HRs	100	137.41	3.21	1.17	21.71	-9.24	**154.26**	0.00	0.00	**0.00**	**154.26**
Solar Photovoltaic (Thin Film) 100 MW	100	100.46	2.35	0.86	22.21	-6.77	**119.10**	0.00	0.00	**0.00**	**119.10**
Solar Photovoltaic (Single Axis) 100 MW	100	129.95	3.03	1.11	20.85	-8.74	**146.20**	0.00	0.00	**0.00**	**146.20**
Solar Photovoltaic (Thin Film) 20 MW	20	120.51	2.81	1.03	22.30	-8.11	**138.54**	0.00	0.00	**0.00**	**138.54**
Solar Photovoltaic (Single Axis) 20 MW	20	146.94	3.43	1.26	20.93	-9.88	**162.68**	0.00	0.00	**0.00**	**162.68**
Wind - Class 3 100 MW	100	69.91	3.26	5.97	0.00	-2.53	**76.61**	0.00	15.29	**15.29**	**91.90**
Wind - Class 4 100 MW	100	70.79	3.31	6.05	0.00	-2.57	**77.58**	0.00	15.29	**15.29**	**92.88**

Source: Energy Commission.

Table E-9: Mid Case Component LCOEs for POU Plants (Nominal $/MWh)—Start-Year=2024

		$/MWh (Nominal 2024$)									
Start-Year = 2024	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Credits & In-lieu	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE at Interconnection Point**
Generation Turbine 49.9 MW	49.9	144.09	19.98	17.96	74.80	0.00	**256.84**	171.36	0.00	**171.36**	**428.20**
Generation Turbine 100 MW	100	144.10	19.98	17.96	72.53	0.00	**254.57**	171.91	0.00	**171.91**	**426.48**
Generation Turbine - Advanced 200 MW	200	74.91	10.39	9.34	44.37	0.00	**139.00**	160.06	0.00	**160.06**	**299.06**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	15.49	2.15	1.93	11.99	0.00	**31.57**	117.47	1.04	**118.50**	**150.07**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	15.34	2.13	1.91	11.99	0.00	**31.38**	117.47	1.04	**118.50**	**149.88**
Biomass Fludized Bed Boiler 50 MW	50	47.85	6.64	5.96	26.19	-0.74	**85.90**	61.23	9.09	**70.32**	**156.23**
Geothermal Binary 30 MW	30	63.28	8.78	7.89	24.03	-0.98	**103.00**	0.00	0.00	**0.00**	**103.00**
Geothermal Flash 30 MW	30	75.93	10.53	9.46	25.62	-1.17	**120.38**	22.05	0.00	**22.05**	**142.43**
Solar Parabolic Trough W/O Storage 250 MW	250	98.55	6.83	1.84	50.99	-1.52	**156.69**	0.00	0.00	**0.00**	**156.69**
Solar Parabolic Trough With Storage 250 MW	250	86.74	6.02	1.08	31.43	-1.34	**123.92**	0.00	0.00	**0.00**	**123.92**
Solar Power Tower W/O Storage 100 MW	100	93.91	6.51	1.76	31.97	-1.45	**132.69**	0.00	0.00	**0.00**	**132.69**
Solar Power Tower With Storage 100 MW 6 HRs	100	101.71	7.05	1.27	32.12	-1.57	**140.58**	0.00	0.00	**0.00**	**140.58**
Solar Power Tower With Storage 100 MW 11 HRs	100	81.09	5.62	1.01	23.08	-1.25	**109.55**	0.00	0.00	**0.00**	**109.55**
Solar Photovoltaic (Thin Film) 100 MW	100	61.01	4.23	0.76	23.86	-0.94	**88.91**	0.00	0.00	**0.00**	**88.91**
Solar Photovoltaic (Single Axis) 100 MW	100	78.19	5.42	0.97	22.19	-1.21	**105.56**	0.00	0.00	**0.00**	**105.56**
Solar Photovoltaic (Thin Film) 20 MW	20	73.18	5.07	0.91	23.95	-1.13	**101.99**	0.00	0.00	**0.00**	**101.99**
Solar Photovoltaic (Single Axis) 20 MW	20	88.41	6.13	1.10	22.28	-1.37	**116.56**	0.00	0.00	**0.00**	**116.56**
Wind - Class 3 100 MW	100	41.76	5.79	5.20	0.00	-0.65	**52.11**	0.00	16.06	**16.06**	**68.17**
Wind - Class 4 100 MW	100	42.29	5.86	5.27	0.00	-0.65	**52.77**	0.00	16.06	**16.06**	**68.83**

Source: Energy Commission.

Table E-10: Mid Case Component LCOEs for Merchant Plants (Nominal $/kW-Year)—Start-Year=2024

		$/kW-Year (Nominal 2024$)									
Start-Year = 2024	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE at Interconnection Point**
Generation Turbine 49.9 MW	49.9	176.68	12.05	17.57	44.64	51.09	**302.03**	65.72	0.00	**65.72**	**367.76**
Generation Turbine 100 MW	100	176.14	12.01	17.52	43.15	50.96	**299.78**	65.72	0.00	**65.72**	**365.50**
Generation Turbine - Advanced 200 MW	200	138.29	9.44	13.77	39.69	39.94	**241.14**	92.02	0.00	**92.02**	**333.15**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	147.38	9.89	14.43	54.36	48.64	**274.70**	513.16	4.72	**517.88**	**792.57**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	145.85	9.79	14.28	54.36	48.14	**272.41**	513.16	4.72	**517.88**	**790.29**
Biomass Fluidized Bed Boiler 50 MW	50	515.23	43.68	64.80	164.98	-201.59	**587.10**	379.85	57.40	**437.24**	**1024.35**
Geothermal Binary 30 MW	30	662.57	56.49	83.80	139.42	-262.98	**679.29**	0.00	0.00	**0.00**	**679.29**
Geothermal Flash 30 MW	30	733.70	62.54	92.76	139.42	-290.92	**737.50**	99.15	0.00	**99.15**	**836.66**
Solar Parabolic Trough W/O Storage 250 MW	250	298.09	13.09	21.31	93.90	-120.18	**306.21**	0.00	0.00	**0.00**	**306.21**
Solar Parabolic Trough With Storage 250 MW	250	425.59	18.70	5.54	93.90	-171.63	**372.09**	0.00	0.00	**0.00**	**372.09**
Solar Power Tower W/O Storage 100 MW	100	325.63	14.27	23.24	67.35	-130.55	**299.95**	0.00	0.00	**0.00**	**299.95**
Solar Power Tower With Storage 100 MW 6 HRs	100	454.31	19.95	5.91	87.33	-182.94	**384.56**	0.00	0.00	**0.00**	**384.56**
Solar Power Tower With Storage 100 MW 11 HRs	100	504.38	22.14	6.55	87.33	-202.90	**417.51**	0.00	0.00	**0.00**	**417.51**
Solar Photovoltaic (Thin Film) 100 MW	100	169.14	7.48	2.22	41.11	-69.51	**150.44**	0.00	0.00	**0.00**	**150.44**
Solar Photovoltaic (Single Axis) 100 MW	100	262.90	11.55	3.42	46.04	-105.96	**217.95**	0.00	0.00	**0.00**	**217.95**
Solar Photovoltaic (Thin Film) 20 MW	20	202.27	8.94	2.65	41.11	-82.88	**172.08**	0.00	0.00	**0.00**	**172.08**
Solar Photovoltaic (Single Axis) 20 MW	20	296.18	13.01	3.85	46.04	-119.26	**239.82**	0.00	0.00	**0.00**	**239.82**
Wind - Class 3 100 MW	100	141.10	12.00	17.75	0.00	-43.20	**127.65**	0.00	32.62	**32.62**	**160.27**
Wind - Class 4 100 MW	100	137.39	11.68	17.29	0.00	-42.06	**124.30**	0.00	31.37	**31.37**	**155.67**

Source: Energy Commission.

Table E-11: Mid Case Component LCOEs for IOU Plants (Nominal $/kW-Year)—Start-Year=2024

		$/kW-Year (Nominal 2024$)									
Start-Year = 2024	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel	Variable O&M	**Variable Cost**	**Total LCOE at Interconnection Point**
Generation Turbine 49.9 MW	49.9	149.18	6.97	12.75	44.22	15.95	**229.07**	12.90	0.00	**12.90**	**241.98**
Generation Turbine 100 MW	100	148.71	6.95	12.71	42.74	15.91	**227.02**	12.90	0.00	**12.90**	**239.93**
Generation Turbine - Advanced 200 MW	200	117.74	5.50	10.06	39.32	12.61	**185.23**	18.07	0.00	**18.07**	**203.29**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	123.51	5.77	10.56	53.84	17.29	**210.96**	503.80	4.68	**508.48**	**719.44**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	122.22	5.71	10.45	53.84	17.10	**209.33**	503.80	4.68	**508.48**	**717.81**
Biomass Fluidized Bed Boiler 50 MW	50	545.32	25.47	46.61	165.53	-36.93	**746.00**	381.49	57.58	**439.07**	**1185.07**
Geothermal Binary 30 MW	30	713.16	33.31	60.95	139.89	-48.00	**899.30**	0.00	0.00	**0.00**	**899.30**
Geothermal Flash 30 MW	30	786.97	36.75	67.26	139.89	-52.95	**977.93**	100.78	0.00	**100.78**	**1078.71**
Solar Parabolic Trough W/O Storage 250 MW	250	327.45	7.65	4.20	94.05	-22.10	**411.25**	0.00	0.00	**0.00**	**411.25**
Solar Parabolic Trough With Storage 250 MW	250	467.68	10.92	4.00	94.05	-31.49	**545.16**	0.00	0.00	**0.00**	**545.16**
Solar Power Tower W/O Storage 100 MW	100	357.03	8.34	4.58	67.47	-24.03	**413.39**	0.00	0.00	**0.00**	**413.39**
Solar Power Tower With Storage 100 MW 6 HRs	100	498.97	11.65	4.26	87.48	-33.57	**568.80**	0.00	0.00	**0.00**	**568.80**
Solar Power Tower With Storage 100 MW 11 HRs	100	553.78	12.93	4.73	87.48	-37.24	**621.69**	0.00	0.00	**0.00**	**621.69**
Solar Photovoltaic (Thin Film) 100 MW	100	186.28	4.35	1.59	41.18	-12.55	**220.85**	0.00	0.00	**0.00**	**220.85**
Solar Photovoltaic (Single Axis) 100 MW	100	287.45	6.71	2.46	46.12	-19.33	**323.41**	0.00	0.00	**0.00**	**323.41**
Solar Photovoltaic (Thin Film) 20 MW	20	222.56	5.20	1.90	41.18	-14.98	**255.86**	0.00	0.00	**0.00**	**255.86**
Solar Photovoltaic (Single Axis) 20 MW	20	323.73	7.56	2.77	46.12	-21.76	**358.42**	0.00	0.00	**0.00**	**358.42**
Wind - Class 3 100 MW	100	149.34	6.97	12.76	0.00	-5.42	**163.66**	0.00	32.67	**32.67**	**196.33**
Wind - Class 4 100 MW	100	145.42	6.79	12.43	0.00	-5.27	**159.36**	0.00	31.41	**31.41**	**190.77**

Source: Energy Commission.

Table E-12: Mid Case Component LCOEs for POU Plants (Nominal $/kW-Year)—Start-Year=2024

Start-Year = 2024	Size MW	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Credits & In-lieu	Fixed Costs	Fuel	Variable O&M	Variable Cost	Total LCOE at Interconnection Point
		$/kW-Year (Nominal 2024$)									
Generation Turbine 49.9 MW	49.9	89.50	12.41	11.15	46.46	0.00	**159.53**	106.44	0.00	**106.44**	**265.97**
Generation Turbine 100 MW	100	89.22	12.37	11.12	44.91	0.00	**157.62**	106.44	0.00	**106.44**	**264.06**
Generation Turbine - Advanced 200 MW	200	69.74	9.67	8.69	41.31	0.00	**129.41**	149.03	0.00	**149.03**	**278.44**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	73.09	10.14	9.11	56.57	0.00	**148.90**	554.06	4.89	**558.96**	**707.86**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	72.37	10.04	9.02	56.57	0.00	**148.00**	554.06	4.89	**558.96**	**706.96**
Biomass Fludized Bed Boiler 50 MW	50	317.71	44.06	39.60	173.92	-4.91	**570.38**	406.58	60.34	**466.92**	**1037.30**
Geothermal Binary 30 MW	30	387.04	53.68	48.24	146.97	-5.99	**629.94**	0.00	0.00	**0.00**	**629.94**
Geothermal Flash 30 MW	30	435.55	60.41	54.28	146.97	-6.74	**690.48**	126.49	0.00	**126.49**	**816.96**
Solar Parabolic Trough W/O Storage 250 MW	250	190.97	13.24	3.57	98.81	-2.95	**303.64**	0.00	0.00	**0.00**	**303.64**
Solar Parabolic Trough With Storage 250 MW	250	272.75	18.91	3.40	98.81	-4.22	**389.66**	0.00	0.00	**0.00**	**389.66**
Solar Power Tower W/O Storage 100 MW	100	208.22	14.44	3.89	70.88	-3.22	**294.22**	0.00	0.00	**0.00**	**294.22**
Solar Power Tower With Storage 100 MW 6 HRs	100	291.00	20.18	3.63	91.91	-4.50	**402.22**	0.00	0.00	**0.00**	**402.22**
Solar Power Tower With Storage 100 MW 11 HRs	100	322.96	22.40	4.03	91.91	-4.99	**436.30**	0.00	0.00	**0.00**	**436.30**
Solar Photovoltaic (Thin Film) 100 MW	100	110.63	7.67	1.38	43.26	-1.71	**161.24**	0.00	0.00	**0.00**	**161.24**
Solar Photovoltaic (Single Axis) 100 MW	100	170.72	11.84	2.13	48.45	-2.64	**230.50**	0.00	0.00	**0.00**	**230.50**
Solar Photovoltaic (Thin Film) 20 MW	20	132.18	9.17	1.65	43.26	-2.04	**184.21**	0.00	0.00	**0.00**	**184.21**
Solar Photovoltaic (Single Axis) 20 MW	20	192.26	13.33	2.40	48.45	-2.97	**253.47**	0.00	0.00	**0.00**	**253.47**
Wind - Class 3 100 MW	100	88.57	12.28	11.04	0.00	-1.37	**110.52**	0.00	34.06	**34.06**	**144.58**
Wind - Class 4 100 MW	100	86.24	11.96	10.75	0.00	-1.33	**107.62**	0.00	32.75	**32.75**	**140.37**

Source: Energy Commission.

Table E-13: Summary of Total Mid Case LCOEs — Start-Year 2013

Start-Year = 2013 (Nominal $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Generation Turbine 49.9 MW	49.9	275.66	662.81	66.28	185.13	2215.54	221.55	193.34	311.60	31.16
Generation Turbine 100 MW	100	273.83	660.52	66.05	183.47	2202.75	220.28	191.81	310.11	31.01
Generation Turbine - Advanced 200 MW	200	252.33	403.83	40.38	159.41	1266.91	126.69	200.67	215.62	21.56
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	551.42	116.51	11.65	495.20	104.54	10.45	482.63	102.35	10.24
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	548.14	115.81	11.58	492.86	104.05	10.40	481.32	102.08	10.21
Biomass Fluidized Bed Boiler 50 MW	50	812.34	122.04	12.20	941.97	141.53	14.15	820.03	123.54	12.35
Geothermal Binary 30 MW	30	561.31	90.63	9.06	743.97	120.21	12.02	519.74	84.98	8.50
Geothermal Flash 30 MW	30	653.36	112.48	11.25	851.61	146.72	14.67	627.91	109.50	10.95
Solar Parabolic Trough W/O Storage 250 MW	250	329.92	168.18	16.82	448.52	228.73	22.87	325.42	167.93	16.79
Solar Parabolic Trough With Storage 250 MW	250	405.52	127.40	12.74	601.76	189.12	18.91	423.90	134.81	13.48
Solar Power Tower W/O Storage 100 MW	100	342.48	152.58	15.26	471.26	210.04	21.00	336.00	151.53	15.15
Solar Power Tower With Storage 100 MW 6 HRs	100	421.46	145.52	14.55	630.53	217.79	21.78	440.07	153.81	15.38
Solar Power Tower With Storage 100 MW 11 HRs	100	459.85	114.06	11.41	692.04	171.72	17.17	479.73	120.45	12.05
Solar Photovoltaic (Thin Film) 100 MW	100	206.11	111.07	11.11	315.22	170.00	17.00	219.97	121.30	12.13
Solar Photovoltaic (Single Axis) 100 MW	100	241.22	109.00	10.90	365.48	165.22	16.52	254.52	116.57	11.66
Solar Photovoltaic (Thin Film) 20 MW	20	224.21	121.31	12.13	344.46	186.51	18.65	239.16	132.42	13.24
Solar Photovoltaic (Single Axis) 20 MW	20	259.52	117.74	11.77	394.71	179.16	17.92	273.72	125.86	12.59
Wind - Class 3 100 MW	100	181.75	85.12	8.51	223.75	104.74	10.47	160.77	75.80	7.58
Wind - Class 4 100 MW	100	173.08	84.31	8.43	213.61	103.99	10.40	153.55	75.29	7.53

Source: Energy Commission.

Table E-14: Summary of Total Mid Case LCOEs — Start-Year 2024

Start-Year = 2024 (Nominal $)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Generation Turbine 49.9 MW	49.9	367.76	884.24	88.42	241.98	2895.90	289.59	265.97	428.20	42.82
Generation Turbine 100 MW	100	365.50	881.62	88.16	239.93	2880.53	288.05	264.06	426.48	42.65
Generation Turbine - Advanced 200 MW	200	333.15	533.17	53.32	203.29	1615.68	161.57	278.44	299.06	29.91
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	792.57	167.46	16.75	719.44	151.88	15.19	707.86	150.07	15.01
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	790.29	166.97	16.70	717.81	151.54	15.15	706.96	149.88	14.99
Biomass Fludized Bed Boiler 50 MW	50	1024.35	153.89	15.39	1185.07	178.06	17.81	1037.30	156.23	15.62
Geothermal Binary 30 MW	30	679.29	109.68	10.97	899.30	145.31	14.53	629.94	103.00	10.30
Geothermal Flash 30 MW	30	836.66	144.03	14.40	1078.71	185.85	18.59	816.96	142.43	14.24
Solar Parabolic Trough W/O Storage 250 MW	250	306.21	156.10	15.61	411.25	209.72	20.97	303.64	156.69	15.67
Solar Parabolic Trough With Storage 250 MW	250	372.09	116.90	11.69	545.16	171.34	17.13	389.66	123.92	12.39
Solar Power Tower W/O Storage 100 MW	100	299.95	133.63	13.36	413.39	184.24	18.42	294.22	132.69	13.27
Solar Power Tower With Storage 100 MW 6 HRs	100	384.56	132.78	13.28	568.80	196.47	19.65	402.22	140.58	14.06
Solar Power Tower With Storage 100 MW 11 HRs	100	417.51	103.56	10.36	621.69	154.26	15.43	436.30	109.55	10.95
Solar Photovoltaic (Thin Film) 100 MW	100	150.44	81.07	8.11	220.85	119.10	11.91	161.24	88.91	8.89
Solar Photovoltaic (Single Axis) 100 MW	100	217.95	98.49	9.85	323.41	146.20	14.62	230.50	105.56	10.56
Solar Photovoltaic (Thin Film) 20 MW	20	172.08	93.11	9.31	255.86	138.54	13.85	184.21	101.99	10.20
Solar Photovoltaic (Single Axis) 20 MW	20	239.82	108.81	10.88	358.42	162.68	16.27	253.47	116.56	11.66
Wind - Class 3 100 MW	100	160.27	75.01	7.50	196.33	91.90	9.19	144.58	68.17	6.82
Wind - Class 4 100 MW	100	155.67	75.77	7.58	190.77	92.88	9.29	140.37	68.83	6.88

Source: Energy Commission.

APPENDIX F: Summary of Comments

On May 20, 2014, the Energy Commission posted a draft staff report titled *Estimated Cost of New Renewable and Fossil Generation in California*. On June 10, 2014, a notice of availability was sent to the *IEPR* listserver to solicit comments on the report. Stakeholders were asked to submit comments to the Energy Commission by June 27, 2014. The Energy Commission received comments from SCE, PG&E, and the Large-Scale Solar Association. In addition, Michael Wheeler of Recurrant Energy provided comments directly to staff via email on June 23, 2014.

As a result of these comments, staff undertook an extensive review of the issues raised by stakeholders. This section is a summary of the comments received by the Energy Commission, along with the responses by staff to each comment. Changes to the report text are not marked in the body of the report; however, the major changes were made to solar PV and the wind technologies, resulting in major reductions to costs.

Energy Commission staff are indebted to the many thoughtful and helpful comments provided by stakeholders. It remains the ongoing commitment of the Energy Commission to produce high-quality, relevant technical work that is valuable to all stakeholders.

Comment Number	Commenter	Comment	Staff Response
1	**Southern California Edison**	The generation technologies studied in the report have varying levels of availability during times of system stress. Excluding these differences will underestimate the cost of energy from resources, such as wind and solar, with relatively lower availability during times of system stress.	See page 2 of report: "The authors have also limited the scope of this report to estimating the costs to the developer rather than to the utility or ratepayer." The individual developer is not responsible for procuring energy for periods when renewable resources are unavailable.
2		Without any associated storage technology, wind and solar resources cannot optimize energy production relative to market prices. Excluding these differences will overestimate the cost of energy from dispatchable resources, such as simple-cycle and combined cycle combustion turbines.	See above response to comment 1. Any attempt to estimate the cost of renewable energy from the utility perspective is outside the scope of the Report.
3		Intermittent, must-take resources require additional balancing services (i.e. regulation and following) to ensure that system load and generation are balanced at all times. Excluding these differences will underestimate the cost of energy from intermittent resources, such as wind or solar.	See above response to comment 1.
4		P. 97 at PP 2 "Costs that include these ancillary costs can be found in Table 25". No defined or implied definition of "ancillary costs". Explain what "ancillary costs" what they include and the source cost figures.	Ancillary costs as defined in this report are interconnection costs, land costs, and licensing costs. This table and all similar tables have been revised to delineate these costs.
5		P. 107 "Instant costs are for equipment and construction only and do not include costs such as land and permitting costs, which would increase mid costs by about 2 percent" – No supporting reference for the 2% figure. Explain the basis for the stated 2% figure.	Instant costs have been updated for clarification.
6		P. 111 "Instant costs are for equipment and construction only and do not include costs such as land and permitting costs, which would increase mid costs by about 3 percent. This accounts for the differences with the Table 30 values" – No supporting reference for the 3% figure. Explain the basis for the stated 3% figure.	See response to comment 5.

Comment Number	Commenter	Comment	Staff Response
7		Table B-3 “Water treatment facilities cost (ZLD?)” Costs between the two treatment systems can vary significantly. Was the requested cost for process water treatment or a ZLD system?	Table B-3 is informational, only. It delineates the data that was collected. The previous 2007 and 2009 efforts were for specific configurations. The present approach does not rely on specific physical configurations. The mid, high, and low-cost cases are now based on an average, 90 percentile, and 10 percentile cases, respectively, of known total capital costs irrespective of their physical configuration.
8		Table B-3 “Total Capital Cost of Facility” (TCCF). No mention of major electrical systems (GSU, electrical breaker, switchgear, switchyard), HRSG, Catalyst, or Balance of Plant which represents significant project costs. – Explain if this equipment cost is included in the TCCF	See response to comment 7.
9		Table B-4/B-5 Avg. Capacity Factors (CF) – Average CF calculated as a simple average of annual CFs – A weighted average will reflect the variances between respective years CF.	The forecasts of mid, high, and low CFs rely on a number of factors – not just these averages. This difference in procedure would not have changed the estimate.
10		Table B-8 Avg. Heat Rate (HR) – Average HR calculated as a simple average of the annual HR – A weighted average will reflect the variances between respective years CF	See response to comment 9.
11		Table B-14 – The paragraph above the table references three combined cycle cases – The correct reference should be to simple cycle cases. – Delete cite to combined cycle cases and cite simple cycle cases.	Staff agrees and has corrected this error as suggested.
12		Page D-1 “The COG Model will then add ancillary costs as necessary, such as land costs and licensing costs, to get the complete instant cost.” – Meaning of “ancillary” and “complete instant” costs is unclear. – What are “ancillary costs” and “complete instant costs.”	See reply to comment 4. “Complete” in complete instant costs was added to emphasize the inclusion of ancillary costs. Instant costs are also referred to as overnight costs.

Comment Number	Commenter	Comment	Staff Response
13		SCE recommends changes to the report to reflect cost factors that are included in their previous comments that would reflect costs as perceived by the utility rather than just the developer.	This is a point well taken but outside of the intended scope of the Report. Any attempt to estimate the cost to the utility would represent a new and different project scope.
14	**Pacific Gas and Electric**	Some of the costs estimates and trends seem to be out-of-step with current trends going forward, especially for solar PV and wind.	Staff agrees and has revised the wind and solar PV cost trends to better reflect these trends.
15		PG&E encourages the CEC to provide timely updates on cost of existing technologies as well as those of likely emerging resources.	Staff appreciates the support from PG&E on the continued updating of this work.
16		Information on the operational flexibility capability of all resources would be useful.	The operational flexibility capabilities of new and proposed units is the subject of other public proceedings before the CPUC at this time. Energy Commission staff will continue to monitor those proceedings and gather information as appropriate.
17		To facilitate further stakeholder review, the CEC may wish to create a COG model Working Group and provide an overview of the key enhancements to the COG model and specific areas where feedback is most needed.	Energy Commission staff agrees that a group of key stakeholders with interest in the ongoing nature of the work could be helpful. Staff will explore this possibility, among others, in the future.
18		Merchant Installed Capital Cost of Solar PV: Although the price of modules and inverters may continue to decline as technological advances are made and incentives continue, the cost of labor, materials, available land and other costs will increase with inflation.	Energy Commission staff would need some source material to share this viewpoint with PG&E.
19		The report ignores distribution level generation, such as 5-20MW solar that can be financed, constructed, and interconnected more quickly to meet locational demands.	This is outside of the scope of the COG Model. Incorporating the key cost elements of distribution-level resources would require an entirely different model due to the differences in financing and taxes.
20		Projects must be Financeable: The model calculation and inputs should be aligned with the financial models and parameters required by investors to ensure the projects are financeable and can be built.	The terms and parameters of these financial models are assumed to be captured in the actual costs of projects recently constructed. The COG Model is calibrated using actual cost data.

Comment Number	Commenter	Comment	Staff Response
21		CCGT: PG&E's understanding is that the combined cycle cost estimates do not include dry cooling. Given the scarcity of water in California, this is recommended.	The previous 2007 and 2009 efforts were for specific physical configurations. The present approach does not rely on specific physical configurations. The mid, high, and low-cost cases are now based on an average, 90 percentile, and 10 percentile cases, respectively, of known total capital costs irrespective of their physical configuration.
22		Gas Turbine: PG&E finds that the range used for the high and low estimates for capital costs for 49.9 and 100 MW gas turbines to be too extreme.	The report includes two range estimates. One, called the deterministic range, includes estimates of all values pushed to their cost extremes. This creates high and low values that bracket the realm of possibility. A second, probabilistic, range is far more narrow and discussed in Chapter 10.
23		The report should include additional documentation on the derivation of the cost of advanced gas turbine and it's comparability to the cost of conventional gas turbines.	The report shares what information the Commission can make publicly available. Information gathered via survey is confidential, and can only be shared in the aggregate. Discussions of derivation could indirectly expose individual developers' costs.
24		PG&E strongly disagrees with the draft report's assertion that because the IOU's may self-schedule, IOU resources are effectively removed from competition. This simply is not true. This discussion is out of scope for the report and should be removed.	The statement of page 9 of the Draft Report is technically correct. The point is raised to address the issue of why IOU owned CT resources operate with significantly lower capacity factors than either Merchant or POU resources. Staff added clarity to the statement in the final report to remove any confusion about why the point was raised.
25		PG&E recommends adding a section to the report on the proper use of the costs estimates, cautions, caveats, and how other costs such as integration costs, system operational flexibility requirements, and environmental costs need to be taken into consideration in resource investment decisions.	This report and the COG Model are from the standpoint of the developer. Appropriate caveats are included in the report. System operations and other externalities are beyond of the scope of this report and the COG Model.

Comment Number	Commenter	Comment	Staff Response
26	**Large-Scale Solar Association**	In the LSA's view the ranges and scenarios in the report distort actual and likely solar costs.	Solar costs were revised for this final report.
27		LSA recommends the CEC consider other methodologies such as those used by LBNL in its projections of solar pricing trends or E3's recent capital cost review of power generation technologies report.	Energy Commission staff worked closely with Mark Bollinger of LBNL to ensure that all renewable costs are calibrated correctly to the California-specific data available to him.
28		Input assumptions for solar costs in the report are not sufficiently transparent. The draft report is not clear what sources the contractors used or which years formed the basis for the solar cost assumptions.	Staff used publicly available to update solar PV costs. Solar thermal costs, where publicly available data was not available, used contractor blended information from a number of sources, such that the cost scenarios are not direct copies of any individual study. Background sources are listed in the bibliography of the report. However, staff has also tried in the final report to clarify sources where possible.
29		LSA recommends the Draft report be amended to provide further detail on the cost assumptions used and work to incorporate the most up-to-date information available. This includes clarifying how projects were selected for the various scenarios.	Individual projects were not used to create scenarios. Instead, an aggregate of all available information was used to produce the scenarios in the report.
30		It would be helpful to understand why the Draft Report finds that installed costs are always higher than instant costs.	Installed Costs are equal to Instant Costs plus the financing of the construction. By this definition, Installed Costs have to be greater than Instant Costs.
31		LSA would like to further understand how the Transmission Access Charge (TAC) assumptions in chapter 3 were used in developing the solar cost ranges under the various scenarios. The TAC is only applicable to projects if the generation is not used within the CAISO or in cases where generation is wheeled-through CAISO and used by another balancing authority.	The Transmission Access Charge has been removed in this Final Report.
32		The land cost assumptions are also not transparent in the draft report.	Staff has added detail to delineate these costs in the Final Report.

Comment Number	Commenter	Comment	Staff Response
33		The Draft Report does not appear to accurately calculate the different land and installed capacity needs for fixed-tilt and thin-film projects, which generally need more land and installed capacity to generate the same output.	The authors appreciate the comment. The estimates in the NREL study *Land-Use Requirements for Solar Power Plants in the United States* run counter to the view of stakeholders. However, the impact of the study's assumptions to instant and levelized costs are minimal (less than 1% at most). The Report maintains consistency in its assumptions to minimize variability in its estimates. Staff recognizes this as an area for further improvement when additional data becomes available.
34		The draft report appears to conflate cost and capacity factors to derive the high and low cost scenarios for solar thermal (as seen on page 86). Using a low net capacity factor with high capital cost is incorrect. NCF is a function primarily of direct normal insolation and the solar multiple. DNI is unrelated to capital costs while the solar multiple IS correlated with capital costs, rather than anti-correlated as could be interpreted from the table on page 86. LSA recommends: • Assuming a single DNI scenario across the low, mid, high to produce NCF • Assuming that the solar multiple is optimized to produce the lowest LCOW for a given configuration at the assumed solar cost, or • Reduce the differential between the high and low NCF's by picking an excellent and good DNI site, respectively, rather than a poor site, which is not a realistic assumption since CSP will not be constructed in a poor DNI location	Staff agrees, which is why a probabilistic analysis is used instead of a deterministic method. An explanation of how we combine cost factors to form probabilistic estimates can be found in Chapter 10, LCOE Estimates. Figure 55 shows the deterministic approach where all low cost factors are combined and all high cost factors are combined. However, this is presented only to make the argument that this is unrealistic. Figure 56 shows our proposed technique, which is a probabilistic assessment. Figures 58 and 59 show the same relationship but at the busbar, where most of the assessments in the various literatures present their estimates.
35		It would be helpful to note in Chapter 5 that Solar Thermal projects will be built based on net system costs. This does not only take into account the levelized cost of energy but also a projects energy, ancillary services and resource adequacy values over time.	The COG Model only determines how much revenue is needed to be financially feasible, which is partially dependent on the developers capital structure (the amount of debt and equity). It does not make any assumptions about where the revenue comes from.

Comment Number	Commenter	Comment	Staff Response
36	Michael Wheeler	From page 56 – Disagrees that most PV that is under construction or under development is fixed tilt. It may be that of currently installed PV the majority of MW are fixed, but newer BOS costs for single axis tracking makes it the standard. Suggests revising this assumption.	Staff notes the feedback and has removed the language in question.
37		P. 56 – Would not characterize the state of the industry as being mostly thin-film. There will continue to be both thin-film and crystalline technologies used. Also, a thin-film characterization for the industry could inflate fears about toxic cadmium.	Staff notes the feedback and has removed the language in question.
38		P. 57 – After stating that most plants are fixed tilt and thin film, the chart describes the industry only by project size. Why not share the data about mounting ratios and panel technologies here too.	No stakeholder disagrees at this point that thin-film and fixed tilt technologies dominate the market. Breakdowns of this on a national basis are available from NREL if desired.
39		P. 60 – Would like additional granularity on the X-axis on the chart – especially since the difference between $5 and $0.5 is pretty significant and where the learning curve crosses $1 matters to this discussion a lot.	The chart was not produced by the Energy Commission, and therefore we do not have the data to add granularity.
40		P. 63 – The instant cost methodology appears to be flawed. Only when costs are kept to an absolute minimum across all categories can projects be successfully built. In no case can a project have high costs across all of categories and be built. So the high cost scenario will never take place.	A better understanding of how we combine cost factors can be found in Chapter 10, LCOE Estimates. Figure 55 shows the deterministic approach where all low cost factors are combined and all high cost factors are combined. However, this is presented only to make the argument that this is unrealistic. Figure 56 shows our proposed technique, which is a probabilistic assessment. Figures 58 and 59 show the same relationship but at the busbar, where most of the assessments in the various literatures present their estimates.

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41		P. 68 - The reader would seem to be led to believe that all thin-film projects are fixed and never tracking, something that is not correct.	Staff agrees that thin-film project can also be tracking. However, the Report assumes that thin-film projects are fixed. Thin-film tracking projects are not analyzed in the COG Model.
42		P. 150 – The capital cost of PV shown here is VERY high.	Staff has reviewed and significantly revised the solar PV data in the report. This includes changing all values in the report to be stated on and AC basis.
43		P. 151 – The current representation makes it look like solar costs will double post 2017.	Staff reviewed market activities and have revised the assumption that the solar tax incentives will expire in 2017. This is based on the fact that developers are still signing contracts that would indicate they expect the incentives to continue.