CALIFORNIA
ENERGY
COMMISSION

COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES

Draft Staff Report

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ABSTRACT

In this 2007 report of the cost of generation of electricity for California located technologies, California Energy Commission staff provides levelized costs, including the cost assumptions, for eight conventional and 20 alternative central station generation technologies. These levelized costs are useful in evaluating the financial feasibility of a generation technology and for comparing the cost of one technology against another. These cost of generation estimates represent one of the first of such efforts based substantially on empirical data collected from operating facilities. The combined cycle and simple cycle costs are the result of a comprehensive survey of actual costs from the power plant developers in California who built power plants between 2001 and 2006. The other costs are based on actual costs and surveys of expected costs from experts in the field. For this reason, staff expects these estimates to have improved accuracy relative to other such estimates. The Energy Commission's Model is also unique in that it has two features not commonly found in cost of generation models: screening curves and cost sensitivity analysis curves. The Energy Commission also uses the fixed cost data of the Model in conjunction with the variable cost information of a production cost market simulation model to produce wholesale electricity costs, which are necessary to many related resource planning studies at the Energy Commission, including Retail Electricity Price Forecasts, Global Warming Evaluations and Electric Vehicle Studies for the AB 1007 Report.

KEYWORDS

Cost of generation, levelized costs, instant cost, installed cost, fixed O&M, variable O&M, heat rate, generation technology cost, annual costs, fixed cost, variable cost, alternative technologies, combined cycle, simple cycle, integrated gasification combined cycle, coal cost, fuel cost, natural gas cost, nuclear fuel cost, heat rate degradation, financial variables, capital cost structure.

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EXECUTIVE SUMMARY

This report provides levelized cost of generation estimates for various central station generation technologies. These levelized costs are useful in evaluating the financial feasibility of a generation technology and for comparing the cost of one technology against another. Since most studies involving new generation or transmission require an assessment of costs, accurate and readily available cost of generation estimates are essential to much of the California Energy Commission's (Energy Commission) work.

Although these levelized costs are useful, care must be taken not to misuse them. It is important to keep in mind that these are nominal values, not precise estimates. They are for a specific set of assumptions that might not be completely applicable for the study in question. More precarious yet is comparing one levelized cost against another, which is useful in the case where levelized costs are of significantly different magnitudes, but problematic where levelized costs are close. Most important is the caution that these estimates do not predict how the units will actually operate in an electric system, how the units will affect the operation of one another, or their effect on system costs. Such estimates require a more sophisticated model such as a market model, which are themselves not perfect. Finally, these cost estimates do not address environmental, system diversity or risk factors which are a vital planning aspect of all resource development.

The levelized costs herein were developed using the Energy Commission's staff cost of generation model (Model). The Energy Commission's Model was first used to produce cost of generation estimates for the *2003 Integrated Energy Policy Report (2003 IEPR)*, which at that time consisted of 25 separate models. Due to the usefulness of the resulting cost estimates and many requests for this type of information, the staff revised the Model to be more compact, accurate and user-friendly. Staff combined the 25 separate cost of generation models of the 2003 version into one Model with drop-down menus. In addition, the Model has been completely reorganized to make it more flexible and more transparent.

Energy Commission staff undertook a comprehensive update of the component costs that are used as inputs to the Model. Staff revised the simple cycle and combined cycle units based on a survey of the power plant developers for all units built in California since 2001. The remaining unit costs are based on a combination of actual costs from the power plant developers and experts in the field.

The staff added a number of analytical functions to the Model. It can now produce screening curves and sensitivity curves to allow users to evaluate the effect of the various cost factors used in developing levelized costs.

The Model, working together with the Marketsym model, can now develop wholesale electricity price forecasts. This feature can estimate the fixed cost component and apply the variable cost factors from the production cost or market model to produce a wholesale electricity price forecast. Wholesale electricity price forecasts are necessary for many of the resource planning studies.

Energy Commission staff improved the documentation and now provide a comprehensive user’s guide to facilitate the use of the Model. Both the Model and the user’s guide will be made available on the web site.

INTRODUCTION

The report summarizes the cost of generation estimates, the assumptions used to develop those estimates and a description of the cost of generation model (Model), which is the tool used to develop these levelized costs.

The report is organized as follows:

- Chapter 1 reports the levelized cost estimates – the output of the Model. It provides the levelized cost estimates for 8 standard technologies and 20 alternative technologies. The levelized costs, as well as the component costs, are provided for three classes of developers: merchant, independently owned utilities (IOU) and publicly owned utilities (municipal utilities).

- Chapter 2 summarizes the inputs to the Model: data assumptions and the collection and analysis process for the improved data. It also compares the effect of the present assumptions to those used in the 2003 IEPR forecast, as well as comparing the present estimates to the EIA estimates.

- Chapter 3 provides a general description of the Energy Commission's Model, provides instructions on how to use the Model and also describes the various new features of the Model that are unique to the Energy Commission's Model, such as screening and sensitivity curves.

- Appendix A provides a summary of people who provided information for this report to facilitate contact points for those interested in aspects of this work.

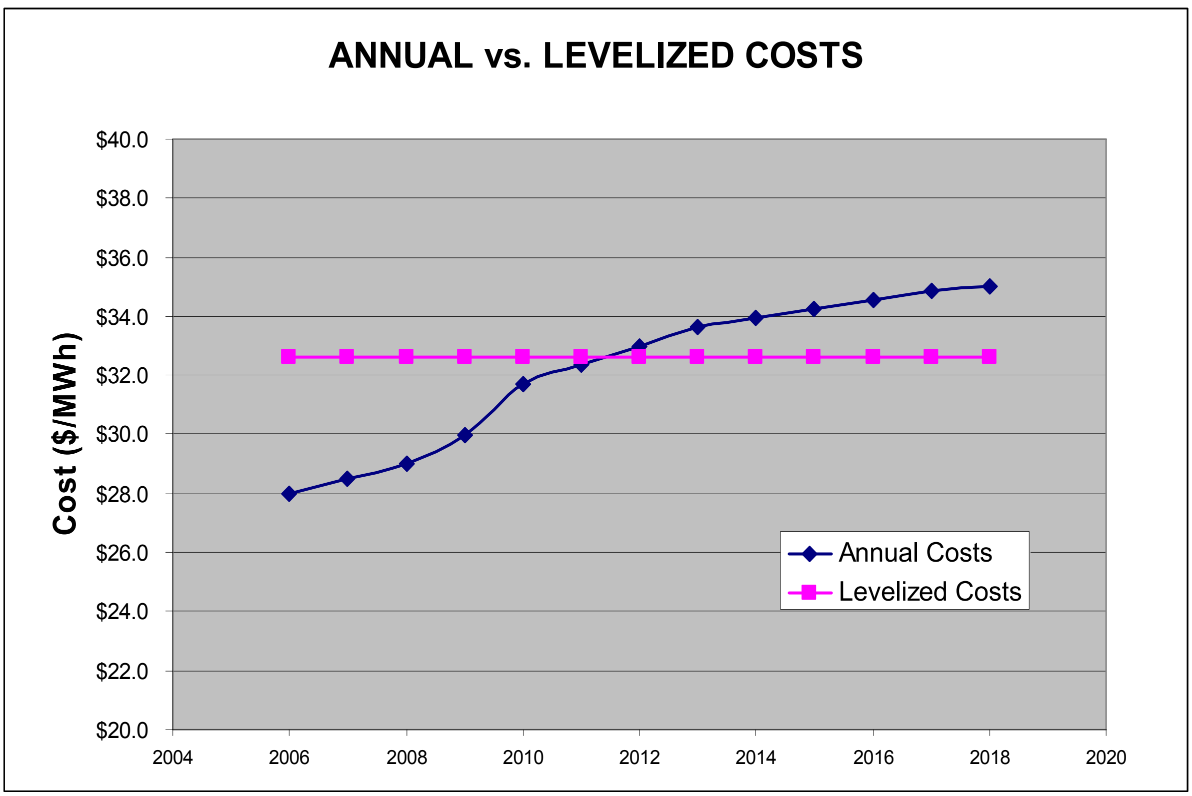
CHAPTER 1: SUMMARY OF TECHNOLOGY COSTS

This chapter defines levelized cost, delineates the cost components of levelized cost and summarizes the levelized costs of the technologies considered in this report. These costs are reported for nuclear, fossil fuel and various alternative technologies.

Definition of Levelized Cost

Levelized cost is the constant annual cost that is equivalent on a present value basis to the actual annual costs, which are themselves variable. Figure 1 is a fictitious illustration of this relationship, which is defined by the fact that the present worth of the annualized levelized cost values is exactly equal to the present worth of the actual annual costs. This annualized cost value allows for the comparison of one technology against the other, whereas the differing annual costs are not easily compared.

Figure 1: Illustration of Levelized Cost



Source: Energy Commission

Levelized Cost Categories

Levelized costs are reported for fixed and variable cost components as shown in Table 1.

Table 1: Summary of Levelized Cost Components

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

Source: Energy Commission

Costs are often reported in dollars per megawatt-hour ($/MWh) or dollars per kilowatt-year ($/kW-Yr). The $/MWh form is the more common one and is useful since it allocates costs to the expected hours of operation. The $/kW-Yr is useful for tracking annual costs where hours of operation are not a concern.

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

Capital and Financing Costs

The capital cost includes the total costs of construction, including land purchase, land development, permitting, interconnection, environmental control equipment and component costs. The financing costs are those incurred through debt and equity financing and are incurred by the developer on an annual basis, similar in structure to financing a home. These annual costs, therefore, are essentially levelized by this cost structure.

Insurance Cost

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

Ad Valorem

Ad valorem costs are annual property tax payments that are paid as a percent of the assessed value and usually transferred to local governments. Publicly owned power plants are generally exempt from these taxes, but may pay in-lieu fees. The assessed values for power plants are set by the State Board of Equalization as a percent of book value for an IOU and as depreciation factored value for a merchant facility.

Fixed Operating and Maintenance

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

Corporate Taxes

Corporate taxes are state and federal taxes, which are not applicable to a publicly owned utility. The calculation of these taxes is different for a merchant facility or an IOU. Neither lends itself to a simple explanation, but in general the taxes depend on depreciated values and are adjusted for interest on debt payments. The federal taxes are adjusted for the state taxes similar to adjustment rates for a home owner.

Fuel Cost

Fuel cost is the cost of fuel, most commonly expressed in dollars per megawatt hour. For a thermal power plant, it is the heat rate (Btu/kWh) multiplied by the cost of the fuel ($/MMBtu). This includes start up fuel costs as well as the online operating fuel usage. Allowance must be made for the degradation of the heat rate over time.

Variable Operations and Maintenance

Variable operation and maintenance costs are a function of the operation of the power plant. Most importantly, this includes yearly maintenance and overhauls. However, this also includes repairs for forced outages, consumables, water supply and annual environmental costs.

Summary of Levelized Costs

Table 2 summarizes the calculated levelized costs for the various generation technologies if developed by merchant, IOU and publicly owned entities. All costs are in 2007 nominal dollars and are for a generation unit that begins operation in the year 2007. Although costs may vary according to location, average California costs are shown. For the gas-fired technologies, average California gas prices are used.

Table 2: Summary of Levelized Costs

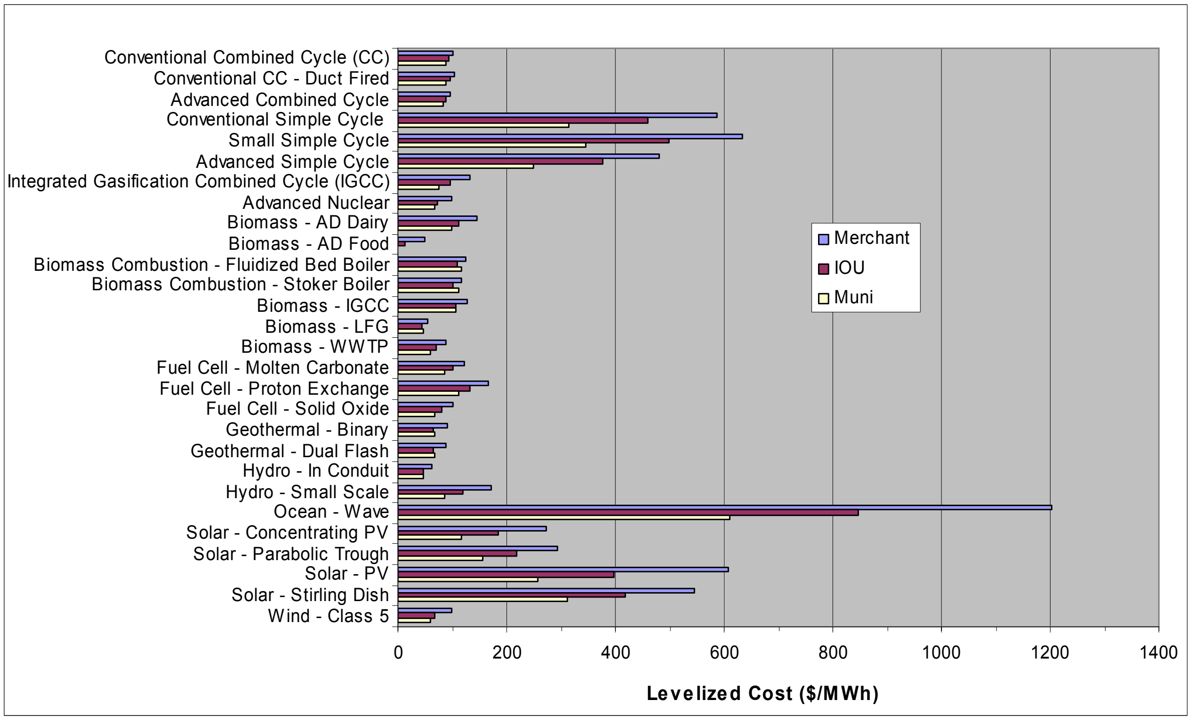
In-Service Year =2007 (Nominal 2007$)	Size	Merchant		IOU		Muni	
	MW	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh
Conventional Combined Cycle (CC)	500	514.56	101.35	476.31	93.97	443.68	87.79
Conventional CC - Duct Fired	550	521.49	102.72	482.14	95.12	448.59	88.77
Advanced Combined Cycle	800	485.30	95.59	447.16	88.22	413.91	81.90
Conventional Simple Cycle	100	250.81	586.36	196.68	460.01	133.90	313.42
Small Simple Cycle	50	270.85	633.21	213.36	499.02	147.98	346.37
Advanced Simple Cycle	200	205.06	479.40	160.83	376.17	106.18	248.52
Integrated Gasification Combined Cycle (IGCC)	575	678.11	131.66	492.79	95.68	384.74	74.70
Advanced Nuclear	1000	728.50	99.86	538.03	73.75	488.88	67.01
Biomass - AD Dairy	0.25	937.69	145.65	723.65	112.41	636.95	98.94
Biomass - AD Food	2	323.64	50.27	80.72	12.54	-51.00	-7.92
Biomass Combustion - Fluidized Bed Boiler	25	915.59	125.49	793.72	108.78	855.28	117.22
Biomass Combustion - Stoker Boiler	25	854.32	117.09	745.23	102.14	814.95	111.69
Biomass - IGCC	21.25	929.64	127.41	781.13	107.06	771.37	105.72
Biomass - LFG	2	370.07	54.49	294.14	43.66	317.72	47.86
Biomass - WWTP	0.5	458.23	87.35	361.82	70.59	296.38	60.36
Fuel Cell - Molten Carbonate	2	933.83	120.84	774.10	100.17	672.03	86.96
Fuel Cell - Proton Exchange	0.03	1289.91	166.91	1026.94	132.89	858.56	111.10
Fuel Cell - Solid Oxide	0.25	776.26	100.45	615.21	79.61	531.28	68.75
Geothermal - Binary	50	573.15	91.82	400.34	66.10	384.60	67.18
Geothermal - Dual Flash	50	542.03	88.67	383.07	64.58	375.70	67.01
Hydro - In Conduit	1	256.67	63.36	183.90	46.09	185.71	48.01
Hydro - Small Scale	10	700.93	171.03	480.62	119.06	338.23	86.43
Ocean - Wave	0.75	1440.72	1201.48	1006.79	846.40	716.79	611.59
Solar - Concentrating PV	15	495.96	271.96	334.48	185.55	204.88	116.23
Solar - Parabolic Trough	63.5	671.03	294.54	497.90	219.23	349.47	154.86
Solar - PV	1	1117.12	608.42	723.14	396.30	461.81	256.29
Solar - Stirling Dish	15	1121.75	544.27	859.49	417.02	643.25	312.10
Wind - Class 5	50	289.10	99.03	195.24	66.88	177.44	60.78

Source: Energy Commission

The IOU plants are less expensive than the merchant facilities due to lower financing costs. This is in marked contrast to the *2003 IEPR* when merchant financing costs were at least comparable to those for the IOUs. The change is a reflection of the outcome from the 2000—2001 energy crisis. The publicly owned plants are the least expensive due to lower financing costs and freedom from taxes.

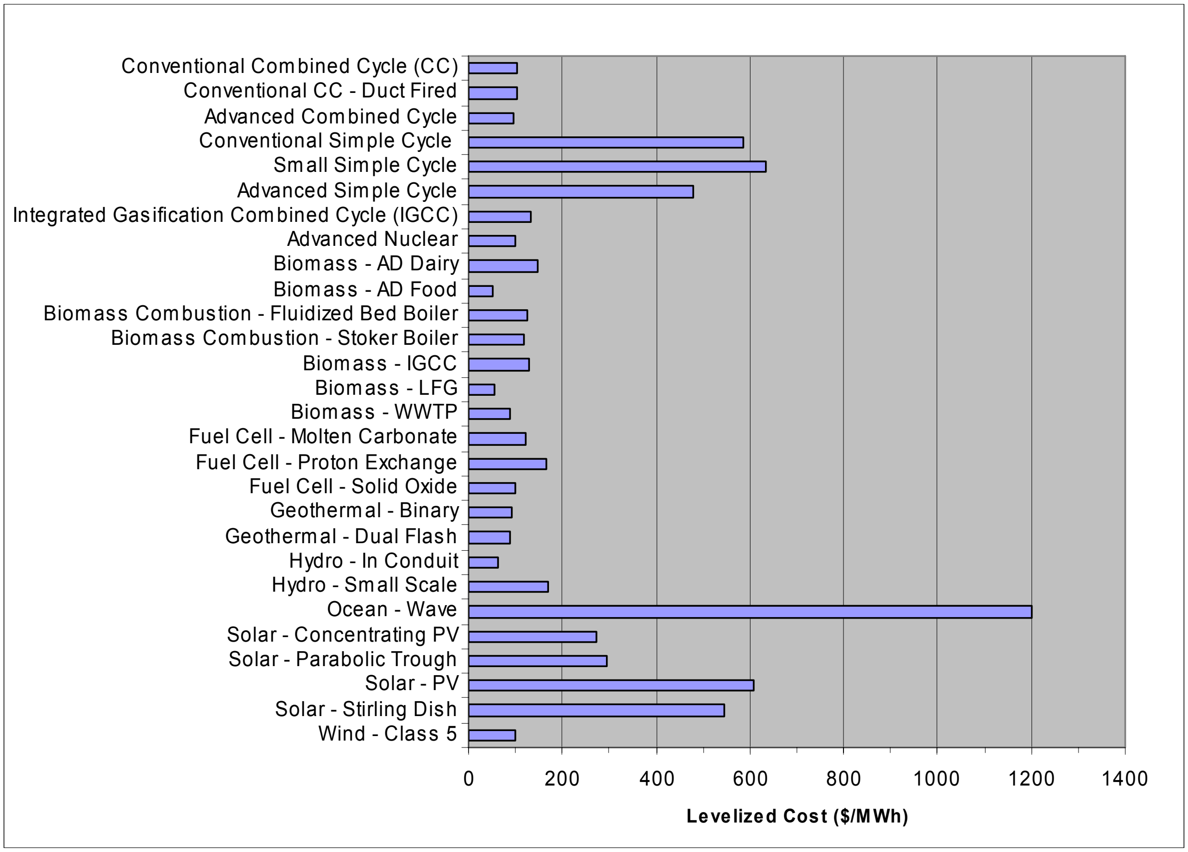
Figure 2 provides this same information in graphical form. To present the information in a less busy representation, Figure 3 shows the data for the merchant facilities only.

Figure 2: Summary of Levelized Costs



Source: Energy Commission

Figure 3: Total Levelized Costs – Merchant Plants Only



Source: Energy Commission

Component Costs

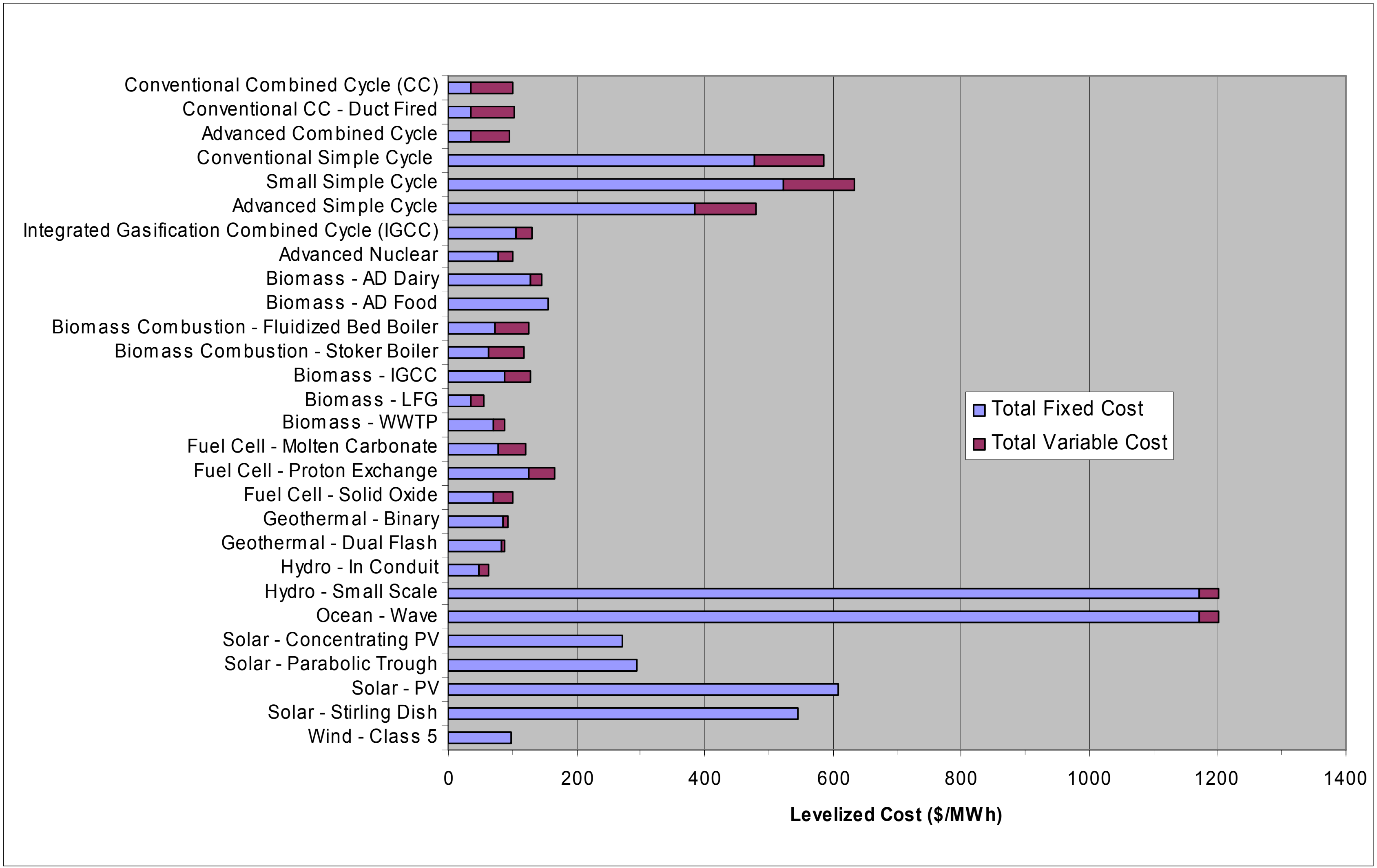
Tables 3, 4 and 5 show the cost components for each developer category, merchant facility, IOU, and publicly owned. Figures 4, 5 and 6 show this same data graphically.

Table 3: Levelized Cost Components – Merchant Plants

In-Service Year =2007	Size MW	$/MWh (Nominal 2007$) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Total Levelized Cost**
Conventional Combined Cycle (CC)	500	22.71	1.13	1.45	2.27	7.66	**35.22**	60.98	5.15	**66.13**	**101.35**
Conventional CC - Duct Fired	550	23.27	1.16	1.48	2.20	7.85	**35.96**	61.76	5.00	**66.76**	**102.72**
Advanced Combined Cycle	800	22.33	1.11	1.42	1.94	7.53	**34.34**	56.79	4.46	**61.25**	**95.59**
Conventional Simple Cycle	100	318.41	15.86	20.27	30.08	91.94	**476.56**	79.70	30.10	**109.80**	**586.36**
Small Simple Cycle	50	338.72	16.87	21.57	48.27	97.55	**522.97**	79.70	30.54	**110.24**	**633.21**
Advanced Simple Cycle	200	260.16	12.96	16.56	19.43	75.21	**384.32**	65.20	29.88	**95.08**	**479.40**
Integrated Gasification Combined Cycle (IGCC)	575	68.03	3.95	6.20	8.84	18.04	**105.06**	22.69	3.90	**26.60**	**131.66**
Advanced Nuclear	1000	54.83	3.18	5.00	9.81	4.67	**77.49**	20.81	1.56	**22.37**	**99.86**
Biomass - AD Dairy	0.25	122.96	6.28	8.03	9.43	-19.53	**127.17**	0.00	18.48	**18.48**	**145.65**
Biomass - AD Food	2	123.60	6.28	8.04	28.28	-10.32	**155.87**	0.00	-105.61	**-105.61**	**50.27**
Biomass Combustion - Fluidized Bed Boiler	25	55.67	3.12	4.48	25.21	-16.57	**71.92**	49.76	3.81	**53.57**	**125.49**
Biomass Combustion - Stoker Boiler	25	51.13	2.86	4.12	22.60	-17.19	**63.52**	49.76	3.81	**53.57**	**117.09**
Biomass - IGCC	21.25	58.23	3.24	4.67	26.06	-4.93	**87.28**	36.33	3.80	**40.13**	**127.41**
Biomass - LFG	2	45.55	2.32	2.96	3.57	-18.12	**36.28**	0.00	18.21	**18.21**	**54.49**
Biomass - WWTP	0.5	71.82	3.65	4.67	4.63	-15.63	**69.14**	0.00	18.21	**18.21**	**87.35**
Fuel Cell - Molten Carbonate	2	81.71	4.15	5.31	0.33	-13.16	**78.35**	0.00	42.48	**42.48**	**120.84**
Fuel Cell - Proton Exchange	0.03	131.80	6.70	8.57	2.83	-25.47	**124.43**	0.00	42.48	**42.48**	**166.91**
Fuel Cell - Solid Oxide	0.25	89.37	4.54	5.81	1.57	-29.98	**71.31**	0.00	29.13	**29.13**	**100.45**
Geothermal - Binary	50	79.77	4.00	5.12	13.61	-16.14	**86.36**	0.00	5.46	**5.46**	**91.82**
Geothermal - Dual Flash	50	75.49	3.78	4.84	15.89	-16.70	**83.30**	0.00	5.37	**5.37**	**88.67**
Hydro - In Conduit	1	49.70	2.82	4.06	0.00	-9.71	**46.88**	0.00	16.48	**16.48**	**63.36**
Hydro - Small Scale	10	895.99	44.11	56.44	30.37	144.23	**1171.14**	0.00	30.35	**30.35**	**1201.48**
Ocean - Wave	0.75	894.17	44.24	56.48	30.47	145.40	**1170.76**	0.00	30.44	**30.44**	**1201.20**
Solar - Concentrating PV	15	378.55	20.60	0.00	30.69	-157.88	**271.96**	0.00	0.00	**0.00**	**271.96**
Solar - Parabolic Trough	63.5	229.78	13.05	0.00	33.39	18.33	**294.54**	0.00	0.00	**0.00**	**294.54**
Solar - PV	1	665.07	37.06	0.00	16.57	-110.28	**608.42**	0.00	0.00	**0.00**	**608.42**
Solar - Stirling Dish	15	390.76	22.19	0.00	100.26	31.06	**544.27**	0.00	0.00	**0.00**	**544.27**
Wind - Class 5	50	86.77	4.84	6.96	13.03	-12.57	**99.03**	0.00	0.00	**0.00**	**99.03**

Source: Energy Commission

Figure 4: Fixed and Variable Costs – Merchant Plants



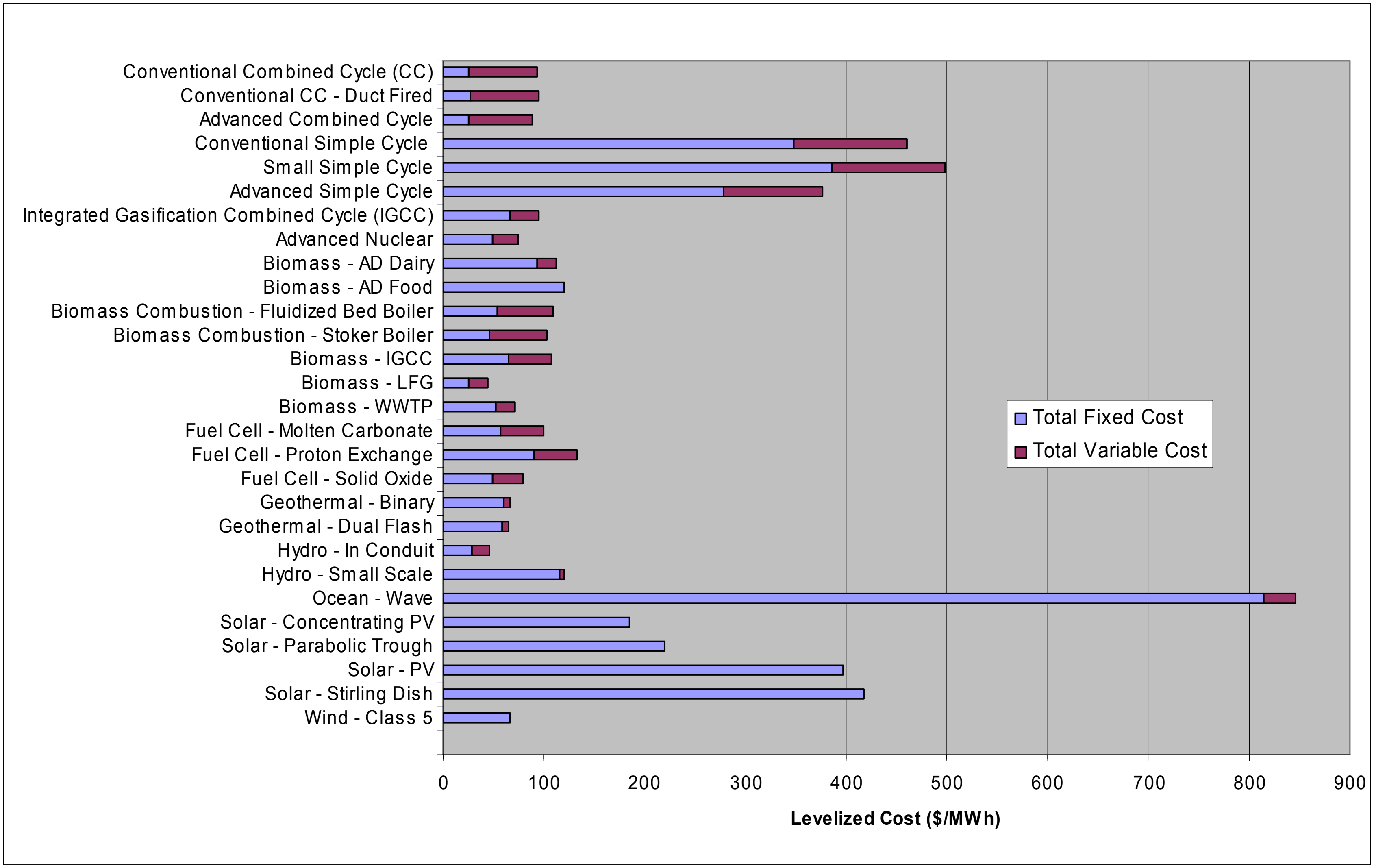
Source: Energy Commission

Table 4: Levelized Cost Components – IOU Plants

In-Service Year =2007	Size MW	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	Total Fixed Cost	Fuel	Variable O&M	Total Variable Cost	Total Levelized Cost
		$/MWh (Nominal 2007$)									
Conventional Combined Cycle (CC)	500	17.84	0.65	1.15	2.33	3.95	**25.92**	62.76	5.29	**68.05**	**93.97**
Conventional CC - Duct Fired	550	18.28	0.66	1.18	2.26	4.05	**26.42**	63.56	5.13	**68.70**	**95.12**
Advanced Combined Cycle	800	17.54	0.64	1.13	1.99	3.89	**25.19**	58.45	4.58	**63.03**	**88.22**
Conventional Simple Cycle	100	248.26	9.01	16.06	30.85	43.04	**347.21**	81.93	30.86	**112.79**	**460.01**
Small Simple Cycle	50	264.09	9.59	17.09	49.49	45.52	**385.77**	81.93	31.32	**113.25**	**499.02**
Advanced Simple Cycle	200	202.84	7.37	13.12	19.93	35.25	**278.50**	67.02	30.64	**97.66**	**376.17**
Integrated Gasification Combined Cycle (IGCC)	575	45.38	2.24	3.98	9.43	5.85	**66.88**	24.63	4.16	**28.80**	**95.68**
Advanced Nuclear	1000	36.58	1.80	3.21	10.46	-3.46	**48.59**	23.49	1.67	**25.16**	**73.75**
Biomass - AD Dairy	0.25	97.41	3.54	6.30	9.65	-23.41	**93.49**	0.00	18.91	**18.91**	**112.41**
Biomass - AD Food	2	97.45	3.54	6.30	28.95	-15.60	**120.65**	0.00	-108.12	**-108.12**	**12.54**
Biomass Combustion - Fluidized Bed Boiler	25	41.11	1.81	3.23	26.33	-19.37	**53.12**	51.69	3.97	**55.67**	**108.78**
Biomass Combustion - Stoker Boiler	25	37.75	1.67	2.97	23.61	-19.52	**46.47**	51.69	3.97	**55.67**	**102.14**
Biomass - IGCC	21.25	42.17	1.86	3.31	27.24	-9.26	**65.32**	37.76	3.97	**41.73**	**107.06**
Biomass - LFG	2	36.16	1.31	2.34	3.69	-18.48	**25.02**	0.00	18.64	**18.64**	**43.66**
Biomass - WWTP	0.5	57.83	2.10	3.74	4.85	-16.57	**51.95**	0.00	18.64	**18.64**	**70.59**
Fuel Cell - Molten Carbonate	2	63.96	2.32	4.14	0.34	-14.08	**56.67**	0.00	43.49	**43.49**	**100.17**
Fuel Cell - Proton Exchange	0.03	103.17	3.75	6.67	2.89	-27.09	**89.39**	0.00	43.49	**43.49**	**132.89**
Fuel Cell - Solid Oxide	0.25	69.95	2.54	4.53	1.61	-28.84	**49.78**	0.00	29.83	**29.83**	**79.61**
Geothermal - Binary	50	61.29	2.23	3.96	14.36	-21.33	**60.51**	0.00	5.59	**5.59**	**66.10**
Geothermal - Dual Flash	50	57.98	2.11	3.75	16.76	-21.51	**59.09**	0.00	5.49	**5.49**	**64.58**
Hydro - In Conduit	1	37.52	1.66	2.95	0.00	-13.26	**28.86**	0.00	17.22	**17.22**	**46.09**
Hydro - Small Scale	10	99.35	4.37	7.78	4.26	-0.25	**115.51**	0.00	3.97	**3.97**	**119.49**
Ocean - Wave	0.75	679.51	24.67	43.96	31.34	35.85	**815.34**	0.00	31.07	**31.07**	**846.40**
Solar - Concentrating PV	15	290.96	11.83	0.00	32.11	-149.34	**185.55**	0.00	0.00	**0.00**	**185.55**
Solar - Parabolic Trough	63.5	171.39	7.56	0.00	35.00	5.28	**219.23**	0.00	0.00	**0.00**	**219.23**
Solar - PV	1	494.31	21.81	0.00	17.43	-137.25	**396.30**	0.00	0.00	**0.00**	**396.30**
Solar - Stirling Dish	15	290.55	12.82	0.00	104.79	8.86	**417.02**	0.00	0.00	**0.00**	**417.02**
Wind - Class 5	50	63.77	2.81	5.01	13.62	-18.34	**66.88**	0.00	0.00	**0.00**	**66.88**

Source: Energy Commission

Figure 5: Fixed and Variable Costs – IOUs



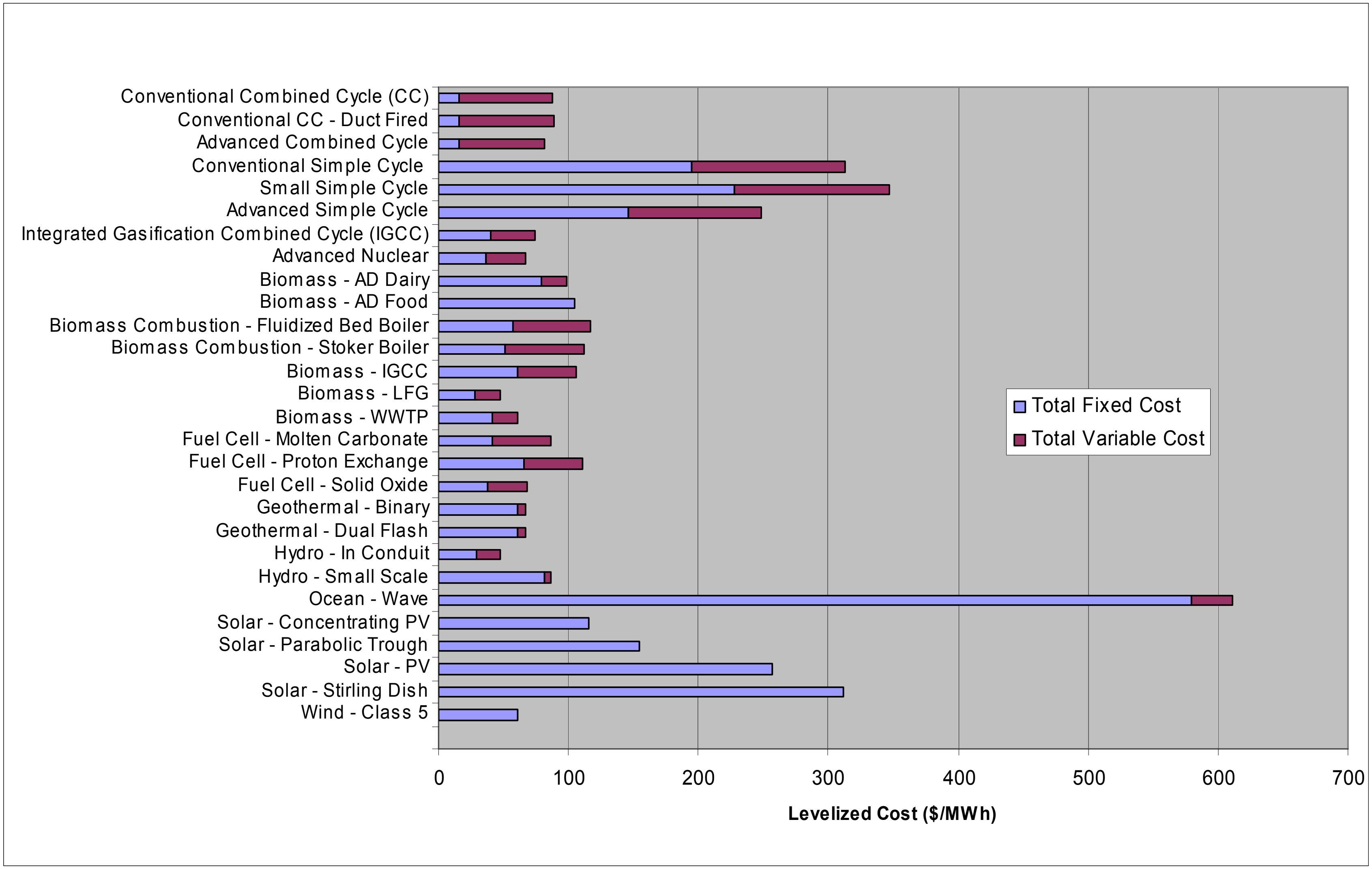
Source: Energy Commission

Table 5: Levelized Costs – Publicly Owned Plants

In-Service Year =2007	Size MW	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	Total Fixed Cost	Fuel	Variable O&M	Total Variable Cost	Total Levelized Cost
		$/MWh (Nominal 2007$)									
Conventional Combined Cycle (CC)	500	11.55	1.10	0.94	2.43	0.00	**16.02**	66.27	5.50	**71.78**	**87.79**
Conventional CC - Duct Fired	550	11.86	1.13	0.96	2.35	0.00	**16.30**	67.13	5.34	**72.47**	**88.77**
Advanced Combined Cycle	800	11.34	1.08	0.92	2.07	0.00	**15.42**	61.72	4.76	**66.49**	**81.90**
Conventional Simple Cycle	100	138.53	13.22	11.25	32.03	0.00	**195.04**	86.33	32.05	**118.38**	**313.42**
Small Simple Cycle	50	149.68	14.29	12.16	51.40	0.00	**227.52**	86.33	32.52	**118.85**	**346.37**
Advanced Simple Cycle	200	106.56	10.17	8.65	20.69	0.00	**146.08**	70.62	31.82	**102.44**	**248.52**
Integrated Gasification Combined Cycle (IGCC)	575	23.13	3.81	2.89	10.81	0.00	**40.64**	29.29	4.77	**34.06**	**74.70**
Advanced Nuclear	1000	18.64	3.07	2.33	11.99	0.00	**36.03**	29.07	1.91	**30.98**	**67.01**
Biomass - AD Dairy	0.25	67.68	6.46	5.50	10.02	-10.34	**79.31**	0.00	19.63	**19.63**	**98.94**
Biomass - AD Food	2	67.71	6.46	5.50	30.04	-5.45	**104.27**	0.00	-112.19	**-112.19**	**-7.92**
Biomass Combustion - Fluidized Bed Boiler	25	25.48	3.37	2.70	28.53	-2.91	**57.17**	55.75	4.31	**60.06**	**117.22**
Biomass Combustion - Stoker Boiler	25	23.40	3.10	2.48	25.58	-2.91	**51.64**	55.75	4.31	**60.06**	**111.69**
Biomass - IGCC	21.25	25.52	3.38	2.70	29.51	-0.42	**60.69**	40.72	4.31	**45.03**	**105.72**
Biomass - LFG	2	25.44	2.43	2.07	3.88	-5.30	**28.52**	0.00	19.34	**19.34**	**47.86**
Biomass - WWTP	0.5	41.77	3.99	3.39	5.25	-13.39	**41.02**	0.00	19.34	**19.34**	**60.36**
Fuel Cell - Molten Carbonate	2	43.91	4.19	3.57	0.35	-10.19	**41.83**	0.00	45.13	**45.13**	**86.96**
Fuel Cell - Proton Exchange	0.03	70.82	6.76	5.75	3.00	-20.37	**65.96**	0.00	45.13	**45.13**	**111.10**
Fuel Cell - Solid Oxide	0.25	48.02	4.58	3.90	1.67	-20.37	**37.80**	0.00	30.95	**30.95**	**68.75**
Geothermal - Binary	50	42.07	4.02	3.42	15.77	-3.90	**61.38**	0.00	5.80	**5.80**	**67.18**
Geothermal - Dual Flash	50	39.78	3.80	3.23	18.40	-3.90	**61.31**	0.00	5.70	**5.70**	**67.01**
Hydro - In Conduit	1	23.70	3.14	2.51	0.00	0.00	**29.35**	0.00	18.66	**18.66**	**48.01**
Hydro - Small Scale	10	62.48	8.27	6.61	4.77	0.00	**82.13**	0.00	4.31	**4.31**	**86.43**
Ocean - Wave	0.75	467.63	44.64	37.98	33.01	-3.90	**579.35**	0.00	32.24	**32.24**	**611.59**
Solar - Concentrating PV	15	192.22	22.02	0.00	34.76	-132.76	**116.23**	0.00	0.00	**0.00**	**116.23**
Solar - Parabolic Trough	63.5	105.62	13.98	0.00	38.17	-2.91	**154.86**	0.00	0.00	**0.00**	**154.86**
Solar - PV	1	312.81	41.39	0.00	19.12	-117.03	**256.29**	0.00	0.00	**0.00**	**256.29**
Solar - Stirling Dish	15	177.93	23.54	0.00	113.54	-2.91	**312.10**	0.00	0.00	**0.00**	**312.10**
Wind - Class 5	50	39.53	5.23	4.18	14.75	-2.91	**60.78**	0.00	0.00	**0.00**	**60.78**

Source: Energy Commission

Figure 6: Fixed and Variable Costs – Publicly Owned Plants



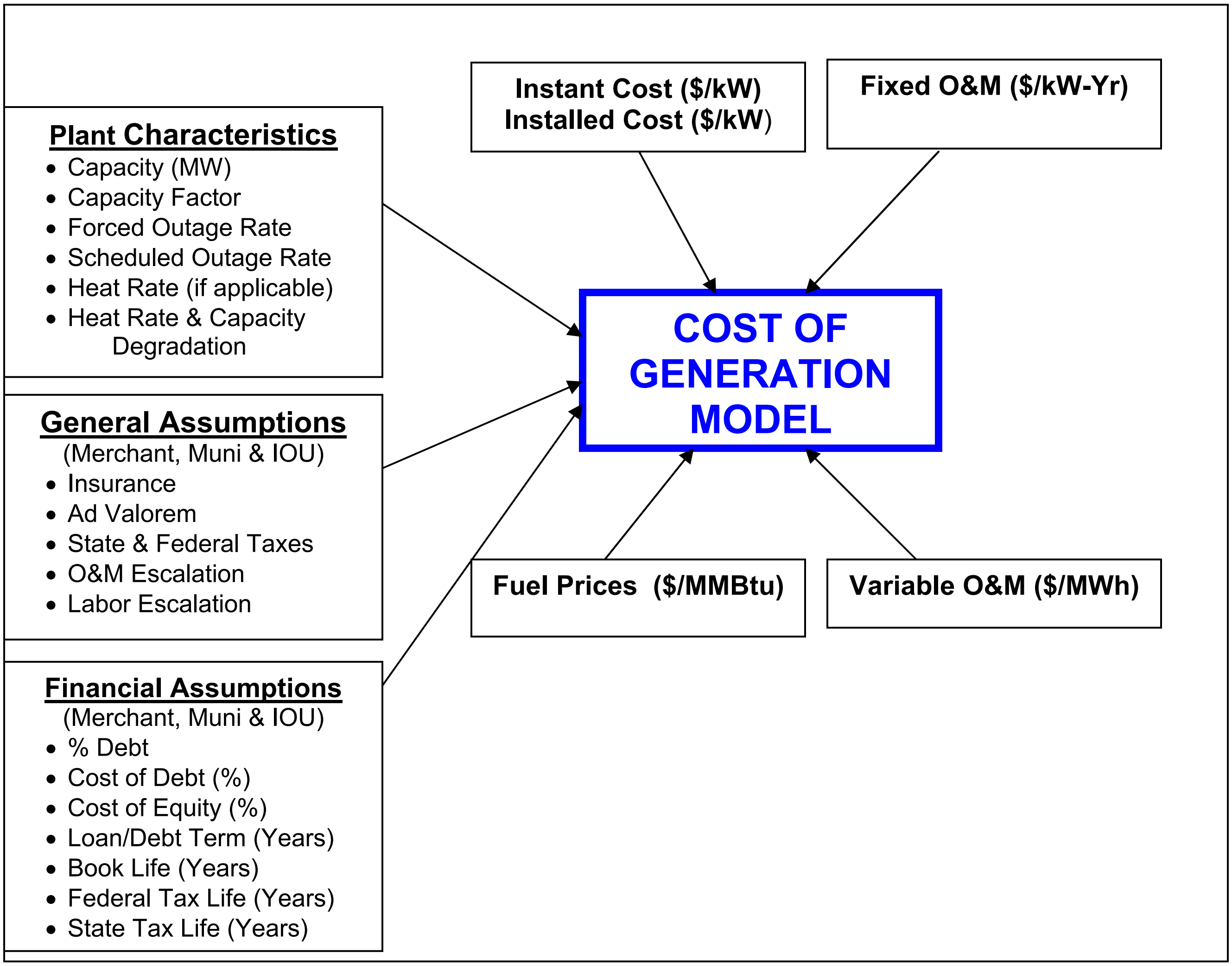
Source: Energy Commission

CHAPTER 2: ASSUMPTIONS

This chapter summarizes the assumptions, the data collection process, the data interpretation process and a comparison to *2003 IEPR* assumptions.

Figure 7 shows the input assumptions that are common to the Model.

Figure 7: Flow Chart of Cost of Generation Model Inputs



Source: Energy Commission

Summary of Assumptions

Tables 6 and 7 summarize the most common input assumptions. All costs are for the year 2007 and are in nominal dollars.

Table 6: Common Assumptions

Technology	Emission Factors (Lbs/MWh)					
	CO2	Nox	Sox	VOC	CO	PM 10
Conventional Combined Cycle	817.62	0.06	0.07	0.02	0.05	0.03
Conventional Combined Cycle - Duct Fired	828.14	0.06	0.07	0.02	0.05	0.03
Advanced Combined Cycle	761.47	0.05	0.07	0.02	0.05	0.03
Conventional Simple Cycle	1083.84	0.09	0.09	0.02	0.09	0.04
Small Simple Cycle	1083.84	0.09	0.09	0.02	0.09	0.04
Advanced Simple Cycle	886.63	0.08	0.08	0.02	0.05	0.03
Integrated Gasification Combined Cycle (IGCC)	1928.00	0.53	0.30	0.00	0.00	0.00
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00
Biomass - AD Dairy	0.00	1.70	0.39	0.00	0.00	0.00
Biomass - AD Food	0.00	1.70	0.42	0.00	0.00	0.00
Biomass Combustion - Fluidized Bed Boiler	0.00	1.24	0.70	0.00	0.00	0.00
Biomass Combustion - Stoker Boiler	0.00	1.24	0.70	0.00	0.00	0.00
Biomass - IGCC	0.00	0.85	0.70	0.00	0.00	0.00
Biomass - LFG	0.00	1.70	0.34	0.00	0.00	0.00
Biomass - WWTP	0.00	1.70	0.39	0.00	0.00	0.00
Fuel Cell - Molten Carbonate	0.00	0.01	0.00	0.00	0.00	0.00
Fuel Cell - Proton Exchange	0.00	0.10	0.00	0.00	0.00	0.00
Fuel Cell - Solid Oxide	0.00	0.05	0.00	0.00	0.00	0.00
Geothermal - Binary	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal - Dual Flash	60.00	0.00	0.35	0.00	0.00	0.00
Hydro - In Conduit	0.00	0.00	0.00	0.00	0.00	0.00
Hydro - Small Scale	0.00	0.00	0.00	0.00	0.00	0.00
Ocean - Wave	0.00	0.00	0.00	0.00	0.00	0.00
Solar - PV	0.00	0.00	0.00	0.00	0.00	0.00
Solar - Parabolic Trough	0.00	0.00	0.00	0.00	0.00	0.00
Solar - Stirling Dish	0.00	0.00	0.00	0.00	0.00	0.00
Solar - Concentrating PV	0.00	0.00	0.00	0.00	0.00	0.00
Wind - Class 5	0.00	0.00	0.00	0.00	0.00	0.00

Source: Energy Commission

Table 7: Emission Factors

Technology	Emission Factors (Lbs/MWh)					
	NOx	VOC	CO	CO2	SOx	PM10
Conventional Combined Cycle	0.056	0.017	0.049	817.62	0.007	0.035
Conventional Combined Cycle - Duct Fired	0.064	0.018	0.050	828.14	0.007	0.028
Advanced Combined Cycle	0.046	0.016	0.046	761.47	0.007	0.026
Conventional Simple Cycle	0.093	0.023	0.093	1083.84	0.009	0.065
Small Simple Cycle	0.093	0.023	0.093	1083.84	0.009	0.065
Advanced Simple Cycle	0.076	0.019	0.053	886.63	0.008	0.053
Integrated Gasification Combined Cycle (IGCC)	0.530	0.000	0.000	1928.00	0.300	0.000
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000
Biomass - AD Dairy	1.700	0.000	0.000	0.000	0.390	0.000
Biomass - AD Food	1.700	0.000	0.000	0.000	0.420	0.000
Biomass Combustion - Fluidized Bed Boiler	1.240	0.000	0.000	0.000	0.700	0.000
Biomass Combustion - Stoker Boiler	1.240	0.000	0.000	0.000	0.700	0.000
Biomass - IGCC	0.850	0.000	0.000	0.000	0.700	0.000
Biomass - LFG	1.700	0.000	0.000	0.000	0.340	0.000
Biomass - WWTP	1.700	0.000	0.000	0.000	0.390	0.000
Fuel Cell - Molten Carbonate	0.010	0.000	0.000	0.000	0.003	0.000
Fuel Cell - Proton Exchange	0.100	0.000	0.000	0.000	0.000	0.000
Fuel Cell - Solid Oxide	0.050	0.000	0.000	0.000	0.000	0.000
Geothermal - Binary	0.000	0.000	0.000	0.000	0.000	0.000
Geothermal - Dual Flash	0.000	0.000	0.000	60.000	0.350	0.000
Hydro - In Conduit	0.000	0.000	0.000	0.000	0.000	0.000
Hydro - Small Scale	0.000	0.000	0.000	0.000	0.000	0.000
Ocean - Wave	0.000	0.000	0.000	0.000	0.000	0.000
Solar - PV	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Parabolic Trough	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Stirling Dish	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Concentrating PV	0.000	0.000	0.000	0.000	0.000	0.000
Wind - Class 5	0.000	0.000	0.000	0.000	0.000	0.000

Source: Energy Commission

Capacity Factor

The capacity factor (CF) is a measure of how much the power plant operates. More precisely, it is equal to the energy generated by the power plant during the year divided by the energy it could have generated if it had run at its dependable capacity throughout the entire year (8,760 hours).

Instant Cost

Instant cost is the initial expenditure, which does not include the costs incurred during construction (see installed cost). These include the component cost, land cost, development cost, permitting cost, linears and environmental control costs.

Installed Cost

Installed cost is equal to the total cost of building a power plant. It includes not only the instant costs, but also the costs associated with the fact that it takes time to build a power plant. Thus, it includes a building loan, sales taxes and the costs associated with escalation of costs during construction.

Fixed Operations and Maintenance

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

Variable Operations and Maintenance

Operations and maintenance is a function of the operation of the power plant and includes:

- Scheduled Outage Maintenance – Annual maintenance and overhauls
- Forced Outage Maintenance
- Water Supply Costs
- Environmental Costs

The annual maintenance and overhaul costs are the largest expenditures.

Capital and Financing Assumptions

Capital and financing assumptions cover the entire cost of building and financing the construction of the power plant. These costs include the amortization of the loan, both principal and interest. This varies depending upon the developer because of the different interest rates available for IOU, publicly owned and merchants. Table 8 summarizes the financial assumptions being used in the Model.

Table 8: Financial Assumptions

	Merchant	IOU	Muni
% Debt	40.0%	50.0%	100.0%
% Equity	60.0%	50.0%	0.0%
Cost of Debt (%)	6.5%	5.73%	4.35%
Cost of Equity (%)	15.19%	11.74%	0.0%

Source: Energy Commission

Insurance

Insurance is calculated differently depending on the type of developer. For an IOU, the cost is based on the book value. For a merchant facility or publicly owned plant, the cost is calculated as a fraction of the installed cost. The fraction used in the Model is 0.6 percent and the annual cost then escalates with nominal inflation.

Ad Valorem

In California, ad valorem (property tax) is different depending on the developer. The merchant owned facility tax is based on the market value assessed by the Board of Equalization. The value reflects the market value of the asset, but may not increase in value at a rate faster than 2 percent per annum per Proposition 13. The Model assumes an initial rate of 1.07 multiplied by the installed cost of the power plant and a property tax depreciation factor. The utility-owned plant tax is based on the value assessed by the State Board of Equalization and is set to the net depreciated book value. The Model assumes an initial cost of 1.07 multiplied by the book value. Counties are allocated property tax revenues based on the share of rate base within each county. Publicly owned plants are exempt from paying property taxes, but may pay a negotiated in-lieu fee.

Corporate Taxes

Corporate taxes are state and federal taxes. Again, these taxes depend on the developer type. A publicly owned utility 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 9.

Table 9: Tax Rates

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

Source: Energy Commission

Fuel Cost

Only the fossil-fueled, nuclear and the integrated gasification combined cycle units have applicable fuel costs. These costs are summarized in Table 10.

Description of Data Gathering and Analysis

Staff conducted two separate data gatherings: one for the combined cycle and simple cycle (combustion turbines) and one for the alternative technologies, clean coal and nuclear.

Combined and Simple Cycle Data Collection

Initially, staff attempted to gather the modeling input information using the Energy Commission’s Application for Certification (AFC) filings, but discovered that the available capital cost data from AFC filings were inadequate. Cost estimates appeared to be inconsistent with one another and unrealistically low. Based on a preliminary assessment, the actual capital costs for building new combined cycle power plants over the last five years were approximately 25 percent higher than the estimated capital costs in recent AFC filings. Additionally, the AFC filings did not contain useful operating cost data.

Staff then decided to request this information directly from the power plant developers. A data request was sent to all the combined cycle (but not cogeneration) and simple cycle power plants that were certified by the Energy Commission starting in 1999 and on line since 2001 through the first quarter of 2006. These plants are summarized in Table 11, together with the in-service year and county location.

Table 10: Fuel Costs (Nominal $/MMBtu)

Deflator Series 2007=1	Year	PG&E	SCE	SDG&E	SMUD	LADWP	IID	CA - Avg.	Uranium	Coal	Biomass
1.00	2007	8.30	8.23	8.74	8.50	8.50	8.50	8.34	0.63	1.47	2.57
1.02	2008	6.72	6.76	7.32	6.81	7.07	7.07	6.82	0.75	1.68	2.63
1.04	2009	6.80	6.80	7.11	6.92	7.06	7.06	6.87	0.89	1.70	2.69
1.07	2010	5.46	5.71	6.20	5.42	6.09	6.09	5.69	1.05	1.72	2.74
1.09	2011	7.04	7.25	7.74	7.05	7.66	7.66	7.26	1.26	1.71	2.80
1.11	2012	6.69	6.84	7.25	6.72	7.22	7.22	6.87	1.50	1.83	2.85
1.13	2013	8.08	8.28	8.59	8.04	8.57	8.57	8.26	1.77	1.90	2.91
1.15	2014	7.39	7.57	7.88	7.36	7.86	7.86	7.56	2.11	1.97	2.97
1.17	2015	8.52	8.61	8.65	8.57	8.90	8.90	8.63	2.58	2.04	3.02
1.20	2016	8.58	8.72	8.82	8.59	9.01	9.01	8.72	2.63	2.12	3.08
1.22	2017	8.63	8.82	8.99	8.60	9.12	9.12	8.80	2.68	2.19	3.14
1.24	2018	9.16	9.42	9.62	9.12	9.77	9.77	9.38	2.73	2.27	3.20
1.26	2019	9.71	10.04	10.28	9.65	10.45	10.45	9.98	2.78	2.35	3.25
1.29	2020	9.91	10.21	10.41	9.87	10.60	10.60	10.16	2.83	2.43	3.32
1.31	2021	10.12	10.38	10.54	10.09	10.75	10.75	10.34	2.89	2.52	3.38
1.34	2022	10.58	10.91	11.10	10.54	11.33	11.33	10.86	2.94	2.59	3.44
1.36	2023	11.06	11.47	11.69	11.00	11.94	11.94	11.39	3.00	2.70	3.51
1.39	2024	11.53	11.87	12.01	11.47	12.28	12.28	11.81	3.05	2.73	3.57
1.41	2025	12.01	12.28	12.35	11.95	12.63	12.63	12.23	3.11	2.83	3.64
1.44	2026	12.44	12.72	12.80	12.37	13.09	13.09	12.67	3.17	2.94	3.71
1.47	2027	12.91	13.21	13.28	12.83	13.58	13.58	13.15	3.23	3.02	3.78
1.49	2028	13.44	13.75	13.79	13.35	14.12	14.12	13.68	3.29	3.12	3.85
1.52	2029	13.96	14.28	14.30	13.87	14.65	14.65	14.21	3.35	3.23	3.92
1.55	2030	14.48	14.80	14.78	14.38	15.16	15.16	14.73	3.41	3.33	3.99
1.58	2031	15.05	15.36	15.31	14.94	15.71	15.71	15.28	3.48	3.44	4.07
1.61	2032	15.65	15.97	15.89	15.53	16.31	16.31	15.89	3.54	3.56	4.14
1.64	2033	16.27	16.59	16.47	16.15	16.92	16.92	16.50	3.61	3.67	4.22
1.67	2034	16.91	17.21	17.05	16.78	17.52	17.52	17.13	3.67	3.77	4.30
1.70	2035	17.57	17.87	17.66	17.43	18.16	18.16	17.78	3.74	3.90	4.38
1.73	2036	18.26	18.55	18.30	18.10	18.83	18.83	18.46	3.81	3.97	4.46
1.77	2037	18.97	19.26	18.96	18.80	19.52	19.52	19.16	3.88	4.04	4.54
1.80	2038	19.72	20.00	19.65	19.53	20.25	20.25	19.90	3.96	4.12	4.63
1.83	2039	20.49	20.77	20.36	20.29	20.99	20.99	20.66	4.03	4.20	4.72
1.87	2040	21.29	21.56	21.09	21.08	21.76	21.76	21.44	4.11	4.27	4.80
1.90	2041	22.12	22.38	21.86	21.90	22.56	22.56	22.26	4.18	4.35	4.89
1.94	2042	22.99	23.24	22.65	22.75	23.39	23.39	23.12	4.26	4.44	4.99
1.97	2043	23.90	24.13	23.47	23.64	24.25	24.25	24.00	4.34	4.52	5.08
2.01	2044	24.83	25.05	24.31	24.56	25.13	25.13	24.92	4.42	4.60	5.17
2.05	2045	25.80	26.01	25.19	25.51	26.06	26.06	25.87	4.51	4.69	5.27

Source: Energy Commission

Table 11: Surveyed Power Plants

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

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

Source: Energy Commission

Capital cost information was requested from all 34 plants, while operating costs were requested from plants that began regular operations until 2005. The data requests for the combined cycle and simple cycle units were divided into capital costs and operating and maintenance costs, as summarized in Table 12.

Table 12: Summary of Requested Data

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

Quality Offsets	

Source: Energy Commission

The information request for each power plant was tailored according to the design of that plant, so that simple cycle facilities did not include questions about steam turbines and duct burners.

After receipt of the information requests responses, they were reviewed and additional data or clarification of data were requested, as appropriate for each power plant, to complete and validate the information to the extent possible. As much of this data was gathered under confidentiality agreements, the details can only be discussed 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 following four categories.

Combined Cycle Capital Costs

By making cost adjustments to each of the combined cycle cost components, all the units could be reduced to a common base case configuration, which is shown in Table 13. These base case costs were then averaged to develop the base installed costs shown in Table 14. These costs include equipment, land, development, air emission control equipment, water treatment and water cooling costs.

Table 13: Base Case Configuration - Combined Cycle

Combined Cycle Base Configuration
1) 500 MW Plant W/O Duct Firing
2) 2 Turbines W/ 1 Steam Generator
3) GE 7F Gas Turbines
4) Wet Cooling
5) Greenfield Site
6) Non-Urban Land Cost
7) Reclaimed Water Source
8) Evaporative Coolers/Foggers
9) Selective Catalytic Reduction (SCR) & Oxidation Catalyst
10) Zero Liquid Discharge (ZLD)
11) Not Co-Located W/ Other Power Facilities
12) 12-Month Licensing Process

Source: Energy Commission

These base case costs were then averaged to develop the base installed costs shown in Table 14. These costs include equipment, land, development, air emission control equipment, water treatment and water cooling costs. The total installed costs are then calculated by estimating the linears (transmission, gas supply, water and sewer), permits (building and environmental) and emission reduction credits (ERCs). The linears and the permits are estimated from the survey data. The ERC costs are based on data developed by Energy Commission staff and calculated by the Model based on that data, for each of the California air districts. The value shown here is an average California value, calculated by the Model.

Table 14: Base Case Installed Costs and Adjustments

500 MW Combined Cycle Unit (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Base Installed Cost	**747**	**753**	**716**
Linears	**66**	**66**	**33**
Permits	**11**	**11**	**11**
ERCs (California Average)	**23**	**23**	**23**
Total Installed Cost	**847**	**852**	**782**

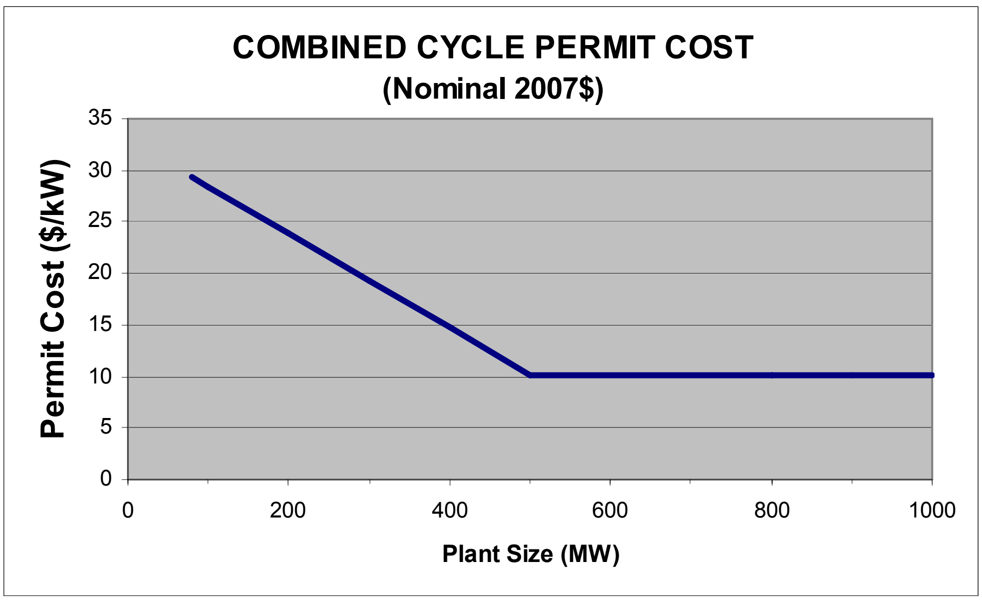
Source: Energy Commission

The above adders are shown as single values. However, permit and ERC costs are variable. Permits were found to be a function of plant size ($Size_{MW}$) and are entered in the Model accordingly:

- 500 MW and above: ***10.2***
- Below 500 MW: (***31 – 0.043*$Size_{MW}$)*(1.06)***

Figure 8 shows this graphically.

Figure 8: Permit Cost as a Function of Plant Size



Source: Energy Commission

Additionally emission reduction credit (ERC) costs are shown as a single average California value, but are a function of the location of the power plant. The cost of ERCs is constantly changing for all areas in California, but ERCs are clearly more costly in some areas than others. The staff anticipates that these costs will increase disproportionately over time and need to be critically evaluated on a regular basis. One particular issue that must be evaluated is the impact of the priority reserve credit costs for the South Coast Air Basin when the South Coast Air Quality Management District finalizes the priority reserve rule 1309.1.

Table 15 shows the total installed costs for the standard combined cycle configurations available in the Model, including the above 500 MW unit. As before, it assumes permit costs and California average ERCs.

Table 15: Total Installed Costs for All Combined Cycle Units

Various Combined Cycle Units (Nominal 2007$)	Merchant ($/kW)	IOU ($/kW)	Muni ($/kW)
Conventional 500 MW CC without Duct Firing	847	852	782
Conventional 550 MW CC with Duct Firing	868	873	803
Advanced 800 MW CC without Duct Firing	833	838	768

Source: Energy Commission

The base installed costs are for a 2-on-1 configuration – two turbines and one steam generator, but the survey determined that the cost was dependent on the configuration. The Model has a selection option to incorporate survey data, which reduces cost approximated at 81 $/kW for each additional turbine and each increases cost by 81 $/kW for a single turbine plant.

Cost adders for less common component costs were also calculated from the survey data that are not incorporated directly into the Model but can be entered exogenously into the Model. These adders are shown in Table 16.

Table 16: Installed Cost Adders for Combined Cycle

Combined Cycle Units (Nominal 2007$)	**$/kW**
Dry Cooling	48
Chillers	11
Plume Abated Cooling Tower	6
No Oxidation Catalyst	-4
Urban Site	11
Co-located facility (Muni only)	-43
Alternative Gas Turbine Type	
SW 501	-32
Alstom GT-24	21
GE 7E	48
Alstom GTX100	53
GE LM6000	16

Source: Energy Commission

Combined Cycle Operating Costs

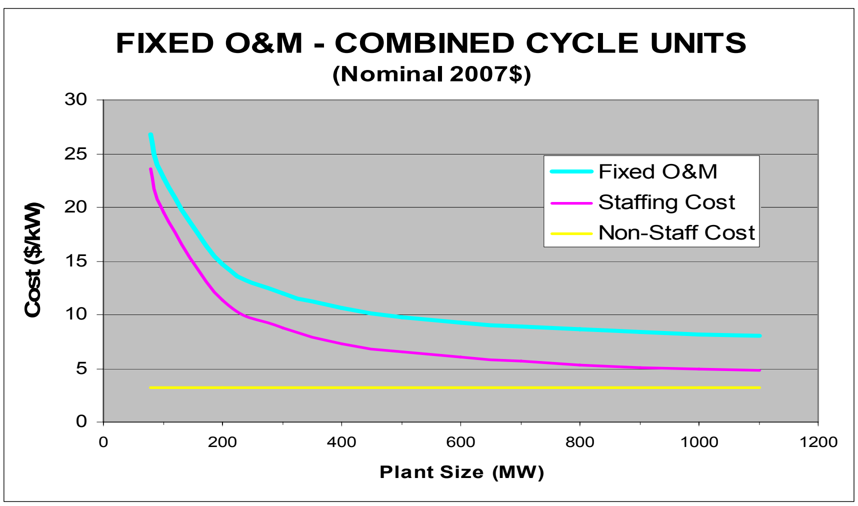
The operating costs consist of three components: fixed O&M, variable O&M, and fuel.

Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are comprised of equipment, regulatory filings and other direct costs (ODCs). These costs were found to vary with plant size as shown in Figure 9.

Variable O&M is composed of the following components:

- Scheduled Outage Maintenance – Annual maintenance and overhauls.
- Forced Outage Maintenance
- Consumables Maintenance
- Water Supply Costs
- Environmental Costs

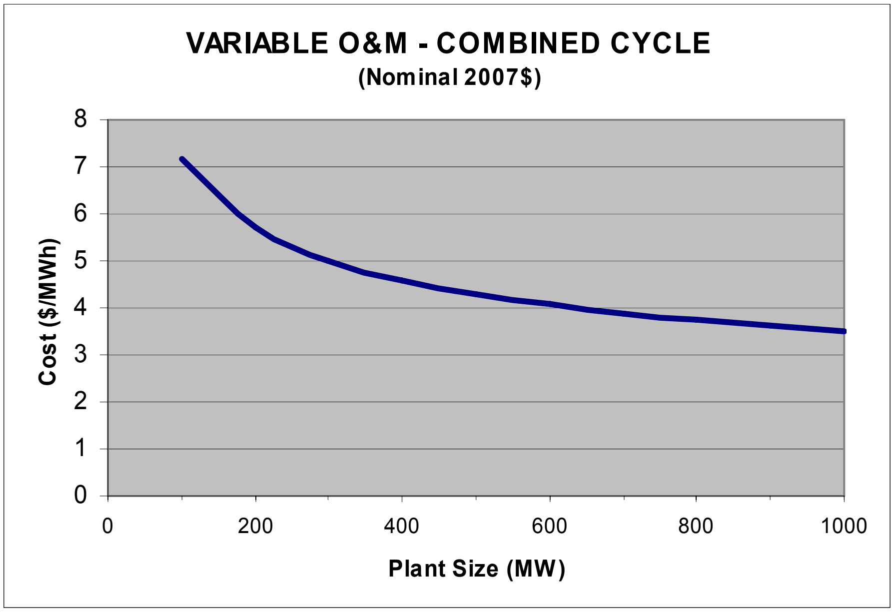
Figure 9: Fixed Operation and Maintenance as a Function of Plant Size



Source: Energy Commission

Figure 10 shows the total variable O&M as a function of plant size. Of all the components, the scheduled and overhaul maintenance is the largest: about 75 to 90 percent of the total cost, depending on the year in question.

Figure 10: Variable Operation and Maintenance Cost as a Function of Plant Size



Source: Energy Commission

Simple Cycle Capital Costs

Similar to the combined cycle units, adjustments were made to each of the simple cycle units so that they could be reduced to a common base configuration, which is shown in Table 17. These base case costs were then averaged to develop the base installed costs shown in Table 18. These costs include equipment, land, development, air emission control equipment, water treatment and water cooling costs.

The total installed costs are then calculated by estimating the linears (transmission, gas supply, water and sewer), permits (building and environmental) and emission reduction credits (ERCs). The linears and the permits are estimated from the survey data; permits were estimated at $21/kW except for units under 50 MW, which were estimated as $8.5/kW. The ERC costs are based on data developed by Energy Commission staff and calculated by the Model based on that information. The Model is able to calculate ERCs for each of the California air districts. The value shown here is an average California value, calculated by the Model.

Table 17: Base Case Configuration - Simple Cycle

1) 100 MW Merchant Plant
2) 2 LM6000 Turbines
3) Wet Cooling Or Dry Cooling
4) Brownfield Site
5) Non-Urban Land Cost
6) Potable Water Source
7) Evaporative Coolers/Foggers
8) Oxidation Catalyst Used
9) ZLD
10) Not Co-Located W/ Other Power Facilities

Source: Energy Commission

Table 18: Base Case Installed Costs and Adjustments

100 MW Simple Cycle Unit (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Base Installed Cost	**942**	**942**	**735**
Linears	**34**	**34**	**34**
Permits	**21**	**21**	**21**
ERCs (California Average)	**3**	**3**	**3**
Total Installed Cost	**1000**	**1000**	**793**

Source: Energy Commission

Table 19 shows the total installed costs for the standard simple cycle configurations available in the Model, including the above 100 MW unit. As before, this includes permit costs and California average ERCs.

Table 19: Total Installed Costs for Simple Cycle Units

Various Simple Cycle Units (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Conventional 50 MW SC	1064	1064	857
Conventional 100 MW SC	1000	1000	793
Advanced 200 MW SC	817	817	610

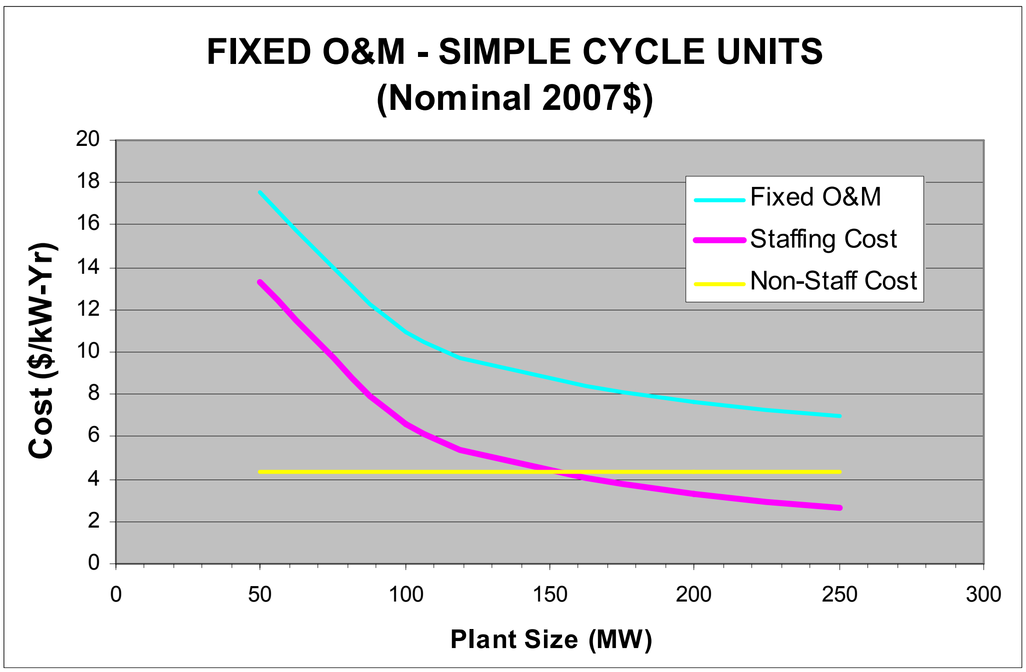
Source: Energy Commission

Simple Cycle Operating Costs

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

Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are comprised of equipment, regulatory filings and other direct costs (ODCs). Staffing costs, and thus fixed O&M, were found to vary with plant size as shown in Figure 11.

Figure 11: Fixed O&M Cost as a Function of Plant Size



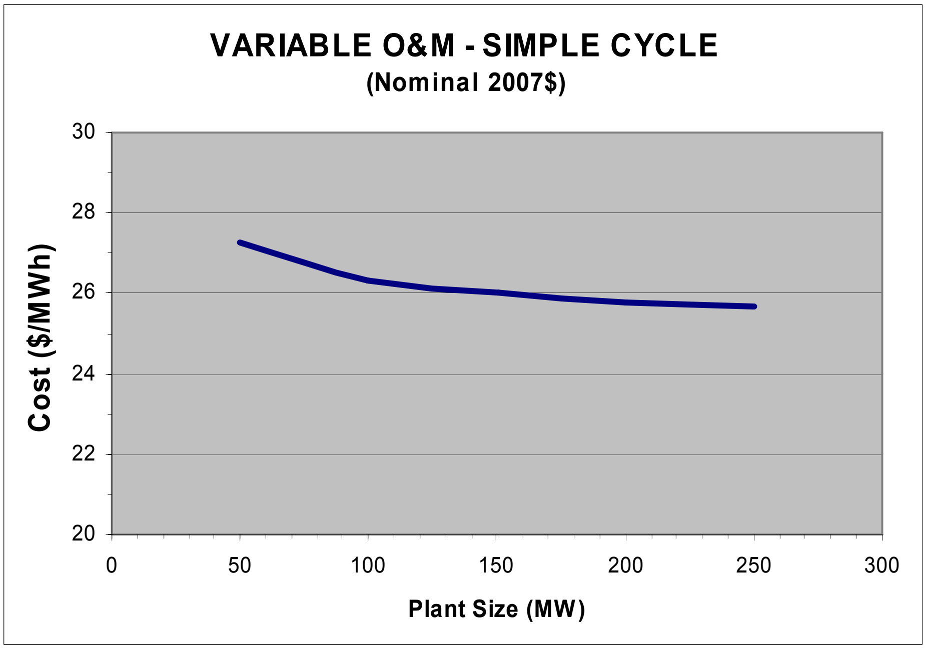
Source: Energy Commission

Variable O&M is composed of the following components:

- Scheduled Outage Maintenance – Annual maintenance and overhauls
- Forced Outage Maintenance
- Consumables Maintenance
- Water Supply Costs
- Environmental Costs

Figure 12 shows the total Variable O&M as a function of plant size. Of the three components, the scheduled and overhaul maintenance is the largest: about 75 to 90 percent of the total cost, depending on the year in question.

Figure 12: Variable O&M Cost as a Function of Plant Size



Source: Energy Commission

Miscellaneous Operating Variables

Heat Rate – Heat rates are a measure of the efficiency of a power plant. An imagined power plant with 100 percent efficiency would have a heat rate of 3413 Btu/KWh. The efficiency of a real power plant can be calculated as 3413 divided by the plant's heat rate. In this report, heat rates are estimated for four categories of thermal power plants:

- Conventional Combined Cycle
- Advanced Combined Cycle
- Conventional Simple Cycle
- Advanced Simple Cycle

The heat rates for all of these plant types were estimated based on actual data taken from the Energy Commission's Quarterly Fuels and Energy Report (QFER) data base. The conventional units were developed by running a statistical regression of the monthly QFER data from 2001 to 2005 for 10 combined cycle and 12 simple cycle facilities. The advanced units were estimated by scaling the conventional values by the difference between the conventional and the advanced units, using Energy Information Administration (EIA) data. Table 20 summarizes the resulting formulas and heat rates for capacity factors of 60 percent for combined cycles and 5 percent for simple cycle units.

Table 20: Summary of Heat Rates

Technology	Heat Rate Formulas	Heat Rate (Btu/kWh)
Conventional Combined Cycle (CC)	***HR =8871+1050*0+2209*CF-4140*CF^.5***	6990
Conventional CC W/ Duct Firing	***HR =8871+1050*.091+2209*CF-4140*CF^.5***	7080
Advanced Combined Cycle	***HR= Conventional CC Heat Rate * (6333/6800)***	6510
Conventional Simple Cycle (SC)	***HR = Regression of QFER data***	9266
Advanced SC	***HR = Conventional SC * (8550/10450)***	7580

Source: Energy Commission

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

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

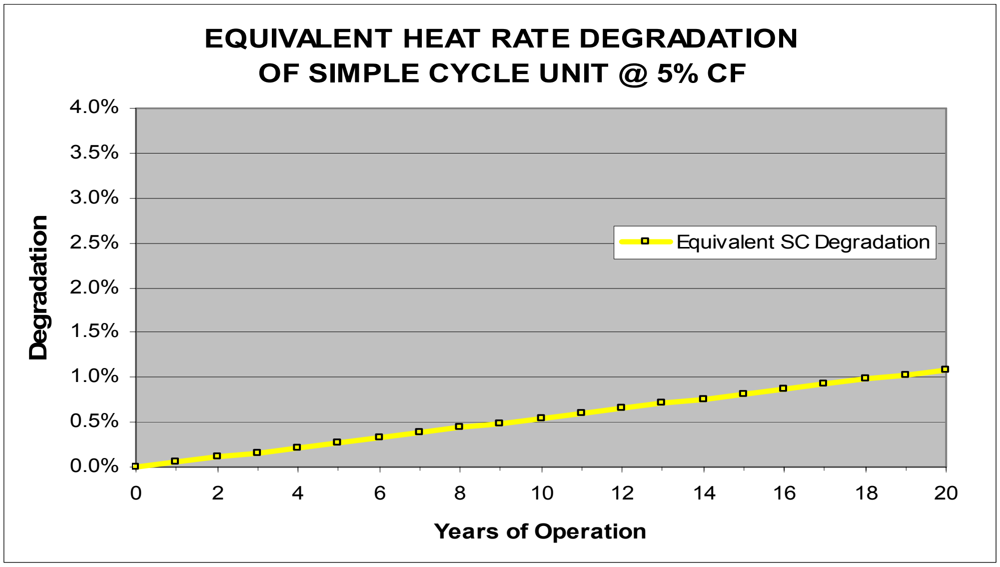
These values were estimated using General Electric data provided under the Aspen data survey. The rule for simple cycle units (combustion turbines) is that they degrade 3 percent between overhauls, which is every 24,000 hours. The actual time between overhauls is a function of capacity factor as shown in Table 21. The staff elected to use a 5 percent capacity factor based on the capacity factors observed in the survey data, and calculated degradation of 0.05 percent per year. Figure 13 shows the results, designated as "Equivalent SC Degradation."

Table 21: Annual Degradation vs. Capacity Factor

Technology	Assumed Capacity Factor	Years Between Overhauls
Simple Cycle Units	5%	55
Simple Cycle Units	10%	27
Combined Cycle Units	50%	5.5
Combined Cycle Units	60%	4.6
Combined Cycle Units	70%	3.9
Combined Cycle Units	80%	3.4

Source: Energy Commission

Figure 13: Simple Cycle Heat Rate Degradation



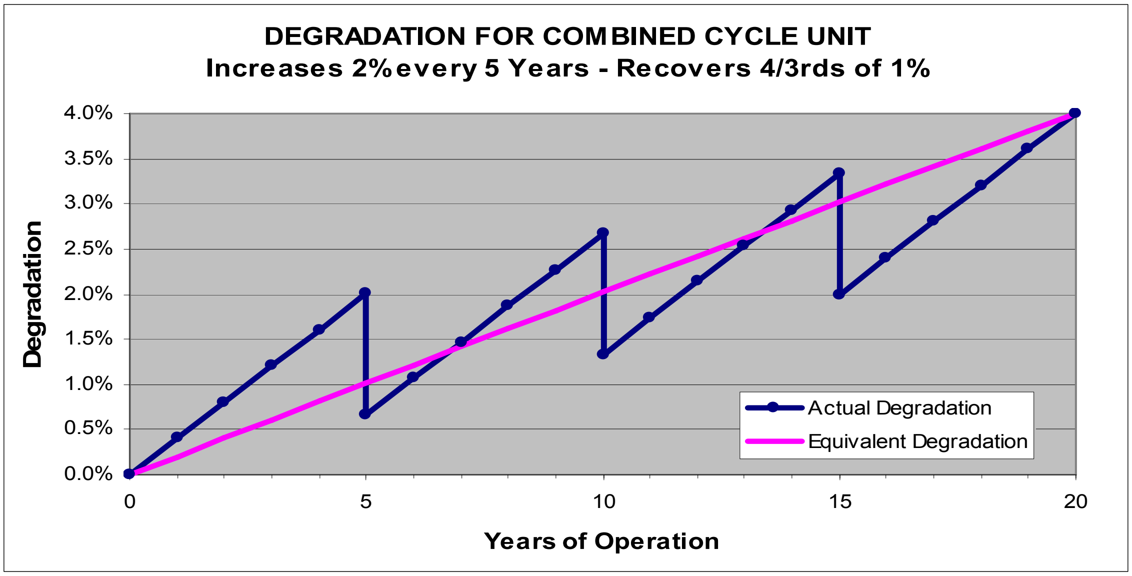
Source: Energy Commission

The computation for the combined cycle units is more complex due to its higher capacity factor – shown to be roughly 60 percent based on the QFER data and other historical information. The 60 percent capacity factor calls for an overhaul every 4.6 years. The staff simplified this assumption by using five years. This results in three major overhauls during its 20 year book life, as show in Figure 14. Since the steam generator portion remains essentially stable, the overall system deteriorates 2 percent during the five-year period and recovers two-thirds of its deterioration during the overhaul. The details of this can be found in the Model User's Guide.

Parasitic Losses – These are sometimes defined as station service losses. This is the power consumed by the power plant as a part of its normal operation. It can also be defined as the difference between the power generated and the power that arrives at the bus bar. The QFER database was used to estimate parasitic losses, which for combined cycle units was estimated to be 2.7 percent.

Transmission and Transformer Losses – Transformer losses are the losses in uplifting the power from the low voltage side of the transformer (generator voltage) to the high voltage side of the transformer (transmission voltage). Transmission losses represent the power lost in getting the power from the high side of the transformer to the load center (hearing designation is "GMM to Load Center").

Figure 14: Combined Cycle Degradation and Recovery



Source: Energy Commission

Staff used assumptions established in the California Public Utility Commission (CPUC) 2005/2006 market price referents (MPRs): 0.5 percent which are summarized in Table 22.

Table 22: Transformer and Transmission Losses Assumptions

LOCATION	LOSSES (%)	POWER (MW)	ENERGY (GWh)
Busbar	--	1.0000	8.059200
High-side of Transformer	0.5%	0.9950	8.018904
Load Center	1.43%	0.9808	7.904234

Source: Energy Commission

Nuclear, Clean Coal and Alternative Technologies

This data was gathered by Navigant Consulting Inc. (Navigant) based on earlier work, document searching and phone calls to knowledgeable people in the field. The source of the data and other questions can be answered by contacting the expert noted in Appendix A.

Navigant provided input data for 22 technologies, 20 alternative technologies, nuclear and integrated gasification combined cycle. The staff processed this data for the Model. The processed data is summarized in Chapter 2 and the resulting levelized costs are summarized in Chapter 1.

It should be noted that Navigant's instant costs are inherently incomplete, in that Navigant is not including emission reduction credit (ERC) costs. Navigant provided the estimated emission factors (lbs/MWh) applicable to each technology. The staff used estimated cost of emissions ($/Ton) in the Model to calculate the cost in dollars. These costs are added to the instant cost provided by Navigant to calculate the total instant cost. The Model converts the instant cost to installed cost and calculates the levelized cost. Table 23 summarizes the Navigant instant and Energy Commission staff instant cost calculation.

Table 23: Instant Cost Adjustments

Technology (All costs in Nominal 2006$)	Gross Capacity (MW)	Navigant Instant Cost ($/kW)	CEC Total Instant Cost
Integrated Gasification Combined Cycle (IGCC)	575	2050	2132
Nuclear	1000	2400	2433
Biomass - AD Dairy	0.25	5300	5625
Biomass - AD Food	2	5300	5627
Biomass Combustion - Fluidized Bed Boiler	25	2750	3061
Biomass Combustion - Stoker Boiler	25	2500	2811
Biomass - IGCC	21.25	2800	3027
Biomass - LFG	2	1850	2180
Biomass - WWTP	0.5	2400	2648
Fuel Cell - Molten Carbonate	2	4350	4352
Fuel Cell - Proton Exchange	0.03	7000	7020
Fuel Cell - Solid Oxide	0.25	4750	4760
Geothermal - Binary	50	3000	3000
Geothermal - Dual Flash	50	2750	2780
Hydro - In Conduit	1	1500	1500
Hydro - Small Scale	10	4000	4000
Ocean - Wave	0.75	6985	6985
Solar - PV	1	9321	9321
Solar - Parabolic Trough	63.5	3900	3900
Solar - Stirling Dish	15	6000	6000
Solar - Concentrating PV	15	5000	5000
Wind - Class 5	50	1900	1900

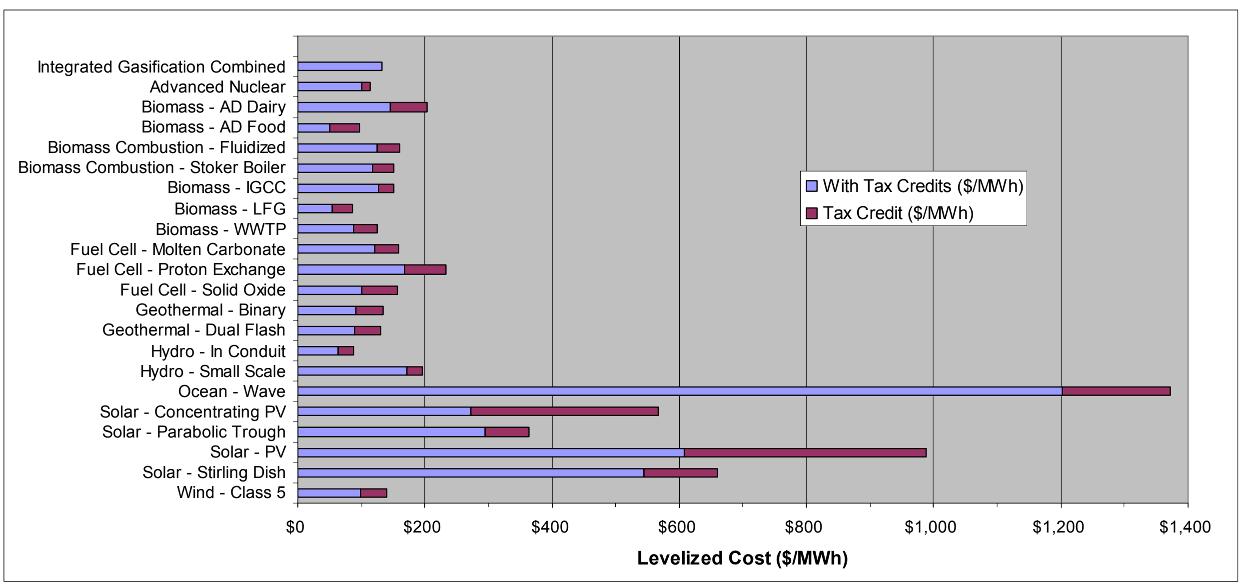
Source: Energy Commission

Table 24: Effect of Tax Credits on Costs

Levelized Costs (2007$)	With Tax Credits	W/O Tax Credits	Tax Credit ($/MWh)	Tax Credit
Integrated Gasification Combined Cycle (IGCC)	$131.66	$131.66	$0.00	0.0%
Advanced Nuclear	$99.86	$113.97	$14.11	14.1%
Biomass - AD Dairy	$145.65	$203.10	$57.45	39.4%
Biomass - AD Food	$50.27	$97.65	$47.38	94.3%
Biomass Combustion - Fluidized Bed Boiler	$125.49	$160.47	$34.98	27.9%
Biomass Combustion - Stoker Boiler	$117.09	$151.19	$34.10	29.1%
Biomass - IGCC	$127.41	$151.28	$23.87	18.7%
Biomass - LFG	$54.49	$86.41	$31.92	58.6%
Biomass - WWTP	$87.35	$124.71	$37.36	42.8%
Fuel Cell - Molten Carbonate	$120.84	$158.76	$37.93	31.4%
Fuel Cell - Proton Exchange	$166.91	$232.27	$65.36	39.2%
Fuel Cell - Solid Oxide	$100.45	$157.47	$57.02	56.8%
Geothermal - Binary	$91.82	$133.81	$41.98	45.7%
Geothermal - Dual Flash	$88.67	$129.83	$41.17	46.4%
Hydro - In Conduit	$63.36	$87.75	$24.39	38.5%
Hydro - Small Scale	$171.03	$195.58	$24.54	14.4%
Ocean - Wave	$1,201.48	$1,371.34	$169.86	14.1%
Solar - Concentrating PV	$271.96	$567.58	$295.62	108.7%
Solar - Parabolic Trough	$294.54	$362.75	$68.21	23.2%
Solar - PV	$608.42	$987.31	$378.89	62.3%
Solar - Stirling Dish	$544.27	$660.51	$116.25	21.4%
Wind - Class 5	$99.03	$139.72	$40.69	41.1%

Source: Energy Commission

Figure 15: Effect of Tax Credits on Costs



Source: Energy Commission

Comparison to 2003 IEPR Assumptions

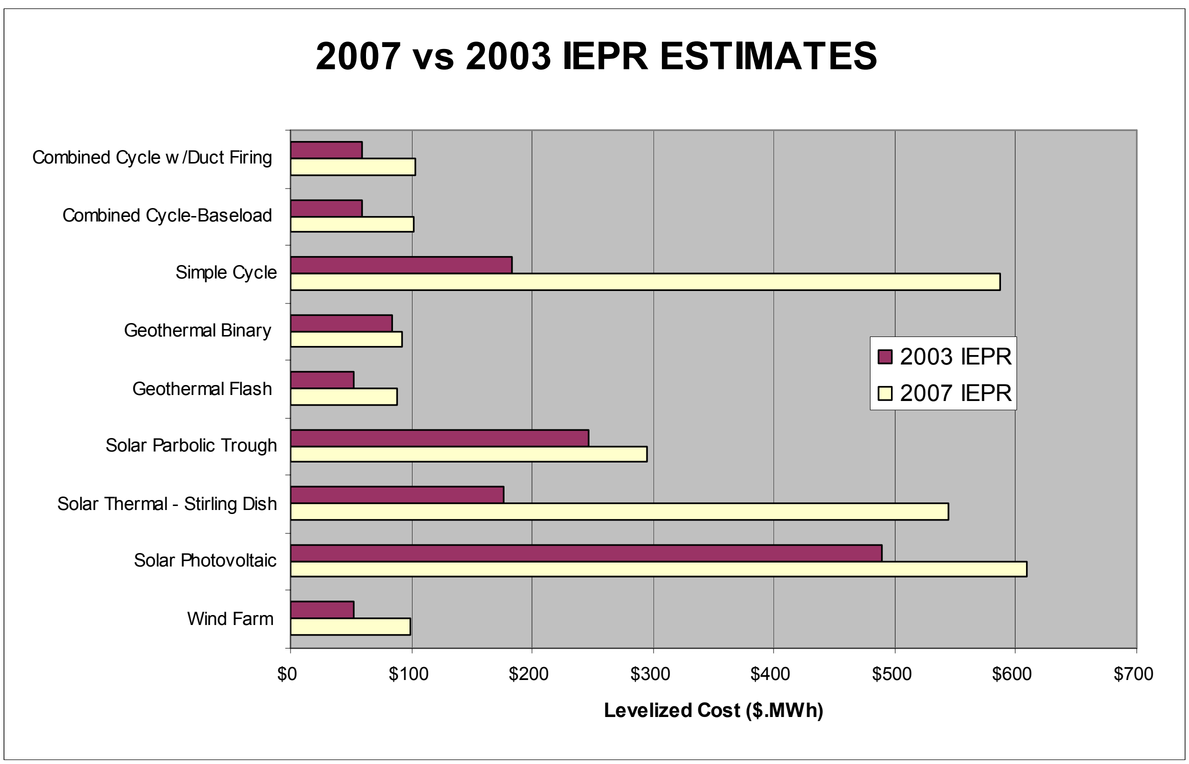
The staff compared the preliminary *2007 IEPR Report* costs to the *2003 IEPR Report* costs, to see how the estimates have changed and to see if the differences are reasonable. Table 25 makes this comparison of the total levelized costs. Figure 16 presents this same data graphically.

Table 25: Levelized Cost of Technology Comparison

Technology (Costs in Nominal 2007$)	2003 IEPR			2007 IEPR			2003 IEPR		2007 IEPR	
	Gross Capacity (MW)	Levelized Cost ($/MWh)	Capacity Factor (%)	Gross Capacity (MW)	Levelized Cost ($/MWh)	Capacity Factor (%)	Instant Cost ($/kW)	Installed Cost ($/kW)	Instant Cost ($/kW)	Installed Cost ($/kW)
Combined Cycle w/Duct Firing	550	$59.73	91.6	550	$102.72	60.0	608	691	803	868
Combined Cycle-Baseload	500	$59.50	91.6	500	$101.35	60.0	620	677	784	847
Simple Cycle	100	$182.62	9.4	100	$586.36	5.0	477	544	925	1000
Geothermal Binary	35	$83.40	98.5	50	$91.82	95.0	3673	4140	3089	3668
Geothermal Flash	50	$51.85	96.0	50	$88.67	93.0	2435	2758	2863	3399
Solar Parbolic Trough	110	$246.40	22.0	63.5	$294.54	63.5	2975	3203	4015	4230
Solar Thermal - Stirling Dish	15	$175.86	36.3	15	$544.27	24.0	3742	4028	6178	6507
Solar Photovoltaic	50	$488.84	23.8	1	$608.42	22.2	7614	8197	8237	5424
Wind Farm	100	$52.93	36.3	50	$99.03	34.0	1015	1093	1956	2009

Source: Energy Commission

Figure 16: Levelized Cost of Technology Comparison



Source: Energy Commission

So many factors have changed since the 2003 IEPR that the differences can only be generally explained. Three technologies have been selected to see if these changes are explainable and reasonable: combined cycle, simple cycle and solar Stirling Dish.

Combined Cycle with Duct Firing:[1] The 2007 IEPR levelized cost is 72 percent higher than that in the 2003 IEPR. Table 26 and the equivalent graphical representation in Figure 17 show how the cumulative effect of changing different assumptions to match the 2003 IEPR assumptions.

If the capacity factor in the 2007 IEPR (60 percent) is adjusted to the 2003 IEPR value (91.6 percent), the levelized cost decreases from $102.72/MWh to $89.12/MWh, which is about 13 percent. If in addition, the 2007 IEPR gas prices, which are about 40 percent higher, are replaced with the 2003 IEPR gas prices, the levelized cost decreases from $89.12/MWh to $74.33, which Is an additional 17 percent. If the 2007 IEPR installed cost, which is about 25 percent higher than the 2003 cost is adjusted then the levelized cost decreases from $74.33/MWh to $69.55/MWh, which is another 7 percent. At this point the two levelized costs are quite close – reasonably explaining most of the difference in the two forecasts. The rest can be explained in terms of capital structure, tax treatment corrections, and higher fixed and variable O&M.

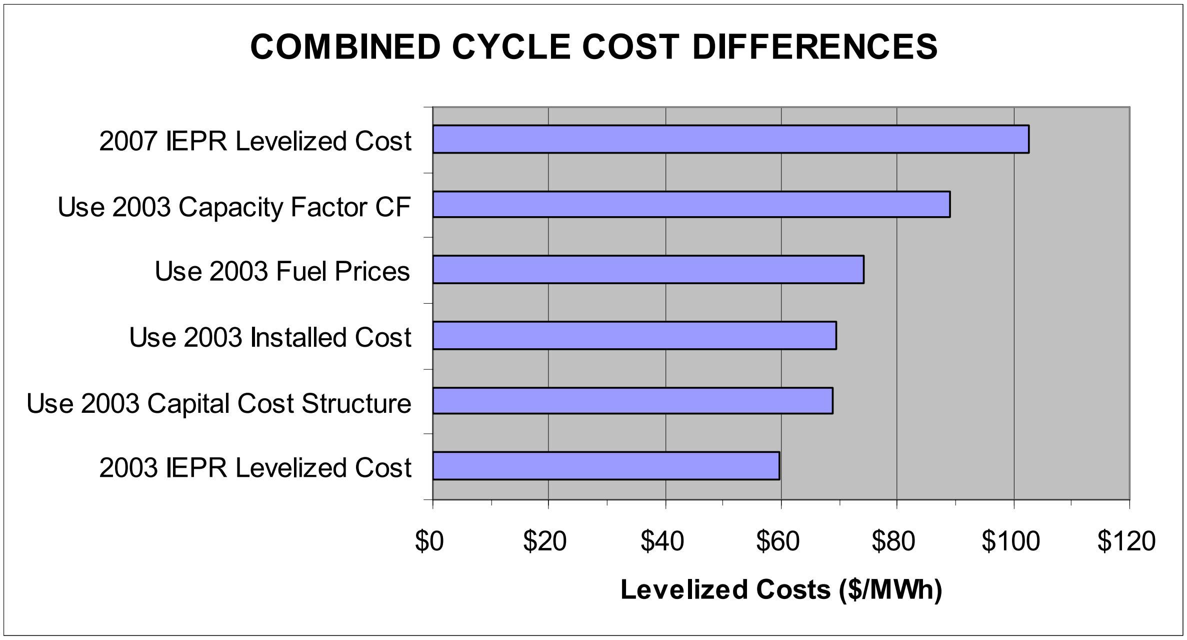
Table 26: 2007 vs. 2003 IEPR – Combined Cycle W/ DF

Effect of Change (2007$)	$/MWh
2007 IEPR Levelized Cost	$102.72
Use 2003 Capacity Factor CF	$89.12
Use 2003 Fuel Prices	$74.33
Use 2003 Installed Cost	$69.55
Use 2003 Capital Cost Structure	$68.93
2003 IEPR Levelized Cost	$59.73

Source: Energy Commission

[1] Duct Firing: A combined cycle plant peaking technology that adds heat to the heat recovery steam generator section of a combined cycle plant to increase steam and power output. Duct burners can be small adding less than 5% additional load or very large adding twenty percent or more to the base load power output.

Figure 17: 2007 vs. 2003 IEPR – Combined Cycle



Source: Energy Commission

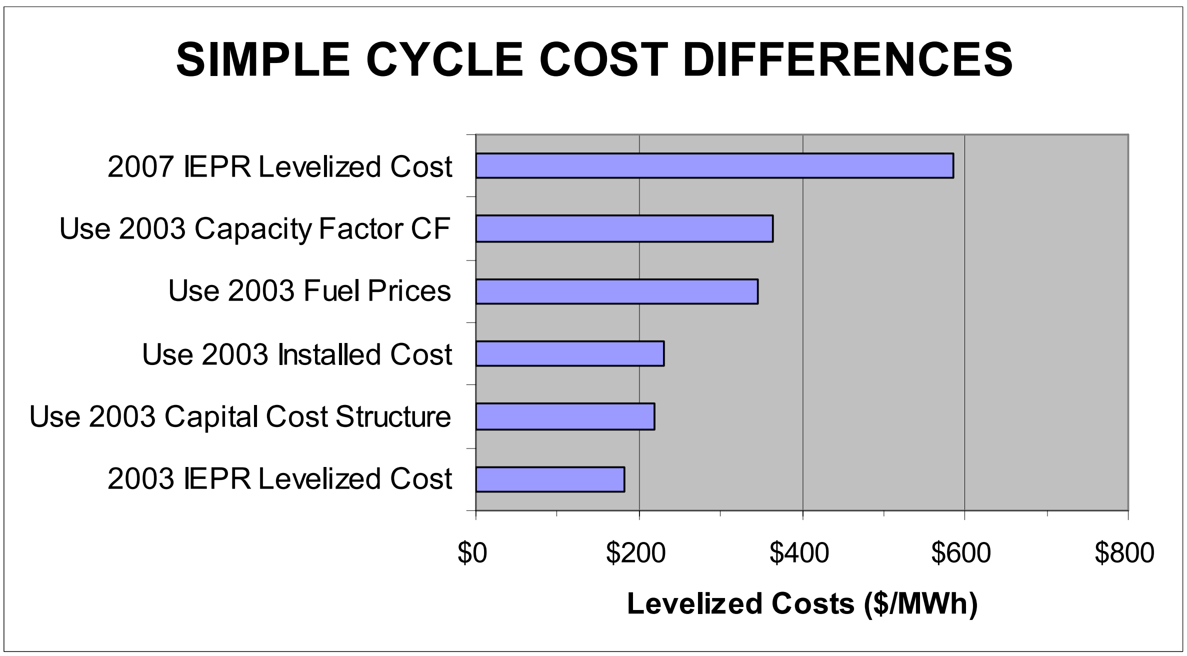
Simple Cycle: The preliminary 2007 IEPR levelized cost is more than three times (3.2) higher than in the 2003 IEPR. Table 27 and Figure 18 rationalize the differences similar to the above combined cycle analysis. If the capacity factor in the 2007 IEPR emulation (5 percent) is adjusted to the 2003 IEPR value (9.4 percent), the levelized cost decreases about 40 percent. If in addition, the 2007 IEPR gas prices which are about 40 percent higher are replaced with the 2003 IEPR gas prices, the levelized cost decreases by another 5 percent. The difference is small due to the small amount of gas used at these lower capacity factors. If the 2007 IEPR installed cost, which is about 90 percent higher than the 2003 cost, the levelized cost decreases another 33 percent. At this point, the two levelized costs are close – reasonably explaining most of the difference in the two forecasts. The rest can be explained in terms of capital structure, tax treatment corrections, and higher fixed and variable O&M.

Table 27: 2007 vs. 2003 IEPR – Simple Cycle

Effect of Change (2007$)	$/MWh
2007 IEPR Levelized Cost	$586.36
Use 2003 Capacity Factor CF	$364.62
Use 2003 Fuel Prices	$345.54
Use 2003 Installed Cost	$231.17
Use 2003 Capital Cost Structure	$219.65
2003 IEPR Levelized Cost	$182.62

Source: Energy Commission

Figure 18: 2007 vs. 2003 IEPR – Simple Cycle



Source: Energy Commission

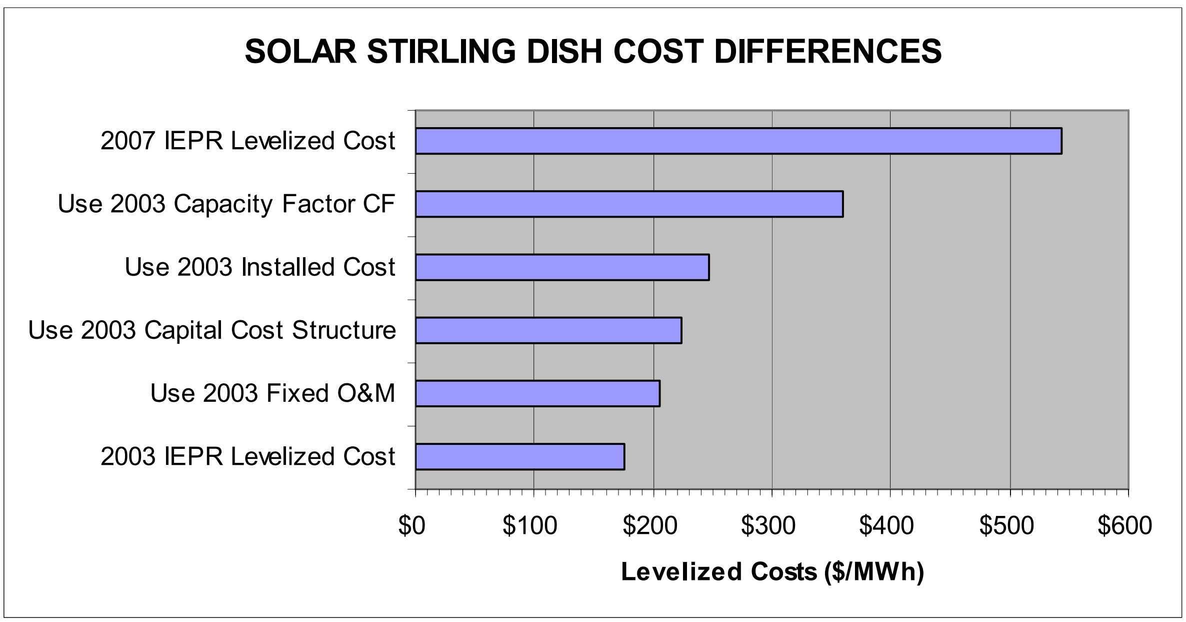
Solar Stirling Dish: The 2007 IEPR levelized cost is approximately three times that of the 2003 IEPR. Table 28 and Figure 19 rationalize the differences similarly to the above analyses. If the capacity factor in the 2007 IEPR (24 percent) is adjusted to the 2003 IEPR value (36.3 percent), the levelized cost decreases about 35 percent. If the 2007 installed cost 6507 $/kW is replaced by the 2003 installed cost of 4028 $/kW, the levelized cost decreases 30 percent. If the 2003 cost of capital are used, the levelized cost decreases an additional 6 percent. If the 2007 IEPR fixed O&M cost (169 $/kW-Yr) is replaced by the 2003 IEPR fixed cost (55 $/kW-Yr), it reduces the levelized cost an additional nine percent. At this point, the two levelized costs are close – within 15 percent. The rest can be explained in terms of tax credits and the change in tax treatment.

Table 28: 2007 vs. 2003 IEPR – Solar Stirling Dish

Effect of Change (2007$)	$/MWh
2007 IEPR Levelized Cost	$544.27
Use 2003 Capacity Factor CF	$359.62
Use 2003 Installed Cost	$247.77
Use 2003 Capital Cost Structure	$224.58
Use 2003 Fixed O&M	$206.30
2003 IEPR Levelized Cost	$175.86

Source: Energy Commission

Figure 19: 2007 vs. 2003 IEPR – Solar Stirling Dish



Source: Energy Commission

Comparison to EIA Assumptions

In order to gain additional perspective on the 2007 IEPR levelized forecast, staff compared the input assumptions against those of the 2007 Energy Information Administration (EIA) estimate. Table 29 makes this comparison for the main assumptions.

Table 29: 2007 IEPR vs. EIA Assumptions

Technology	Size (Gross MW)		Instant Cost ($/kW)			Fixed O&M ($/kW-Yr)			Variable O&M ($/MWh)			Capacity Factor (%)		Heat Rate (Btu/kWh)	
(Nominal 2007$)	CEC	EIA	CEC	EIA	Ratio	CEC	EIA	Ratio	CEC	EIA	Ratio	CEC	EIA	CEC	EIA
Combined Cycle (CC)	500	250	784	641	1.22	9.91	12.49	0.79	4.42	2.07	2.91	60%	87%	6,990	6,800
Advanced CC	800	400	771	632	1.22	8.47	11.70	0.72	3.83	2.00	2.70	60%	87%	6,510	6,333
Simple Cycle (SC)	100	160	925	447	2.07	11.06	12.12	0.9	25.76	3.57	13.5	5%	30%	9,266	10,450
Advanced SC	200	230	756	423	1.79	7.13	10.53	0.7	25.57	3.17	13.8	5%	30%	7,580	8,550
IGCC	575	550	2192	1585	1.38	36.22	38.68	0.2	3.10	2.92	14.5	60%	85%	8,979	6,800
Adv Nuclear	1000	1350	2505	2213	1.13	56.91	67.92	0.8	1.24	0.49	2.5	85%		10,400	10,400
Fuel Cell (Molten Carbonate)	2	10	4481	5085	0.88	2.17	5.65	0.4	36.22	47.95	0.8	90%		8,322	8,832
Geothermal - Binary	50	50	3089	1999	1.55	72.43	164.72	0.4	4.66	0.00	-	95%	90%		
Conventional Hydropower	10	10	4118	1595	2.58	13.45	13.97	1.0	3.10	3.51	0.9	52%			
Wind	50	50	1956	1282	1.53	31.04	30.31	1.0	0.00	0.00	-	34%	34.1%		
Photovoltaic	1	5	8237	5051	1.63	12.42	11.68	1.1	0.00	0.00	-	17.3%			

Source: Energy Commission

In general, the staff data is significantly higher than EIA information, with the notable exception of fixed O&M and some variable O&M. For example, EIA is estimating an instant cost for simple cycle units at $447/kW, which is much lower than staff's $925/kW estimate. Some of these differences can be explained by the higher construction costs in California compared to the nationwide costs used by the EIA. Also, EIA is not accounting for California's ERC costs, and staff believes that they are not accounting for linears.

Staff also feels that the EIA estimates for capacity factors are not reasonable for California. The EIA is estimating an 87 percent capacity factor for combined cycles and 30 percent for simple cycles, where staff is estimating 60 and 5 percent respectively.

CHAPTER 3: COST OF GENERATION MODEL

This chapter describes:

- Model overview
- Model structure
- Model improvements since 2003 IEPR
- Model limitations
- The Model's screening curve function
- The Model's sensitivity curve function
- The Model's wholesale electricity price forecast function

Model Overview

A simplified flow chart of the Model is shown in Figure 20.

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

- Levelized Fixed Costs
- Levelized Variable Costs
- Total Levelized Costs (Fixed + Variable)

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

This Model is more unique than the traditional Model since it can create three other outputs not commonly provided in a Model of this type:

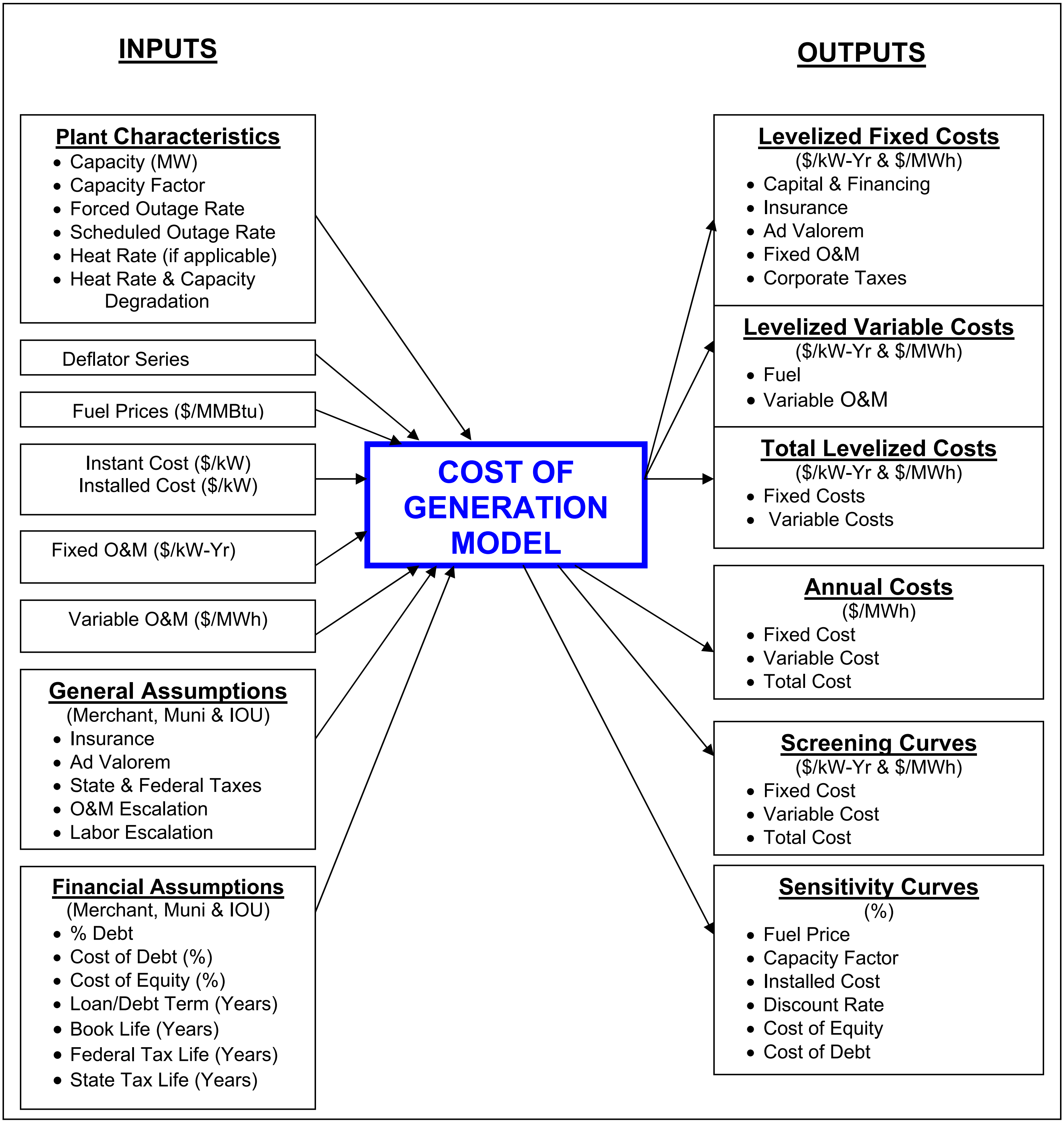
- Annual costs, which are not traditionally displayed in both a table and a graph.

- Screening curves, which show the relationship between levelized cost and capacity factor – an addition that makes the Model much more useful in evaluating COG costs and comparing different technologies.

- Sensitivity curves, which show the percentage change in outputs (levelized cost) as various input variables are changed.

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

Figure 20: Flow Chart for Cost of Generation Model



Source: Energy Commission

Model Structure

The Model is a spreadsheet model that calculates levelized costs for 28 different technologies. These include nuclear, combined cycle, integrated gasification combined cycle, simple cycle and various alternative technologies. The Model is designed to accommodate additional technologies and includes a function for storing the results of scenario runs for these technologies.

The Model is contained within a single Excel file or workbook using Microsoft terminology. This workbook consists of 19 spreadsheets or worksheets using Microsoft terminology, but 4 of these are informational and do not contribute to the calculations.

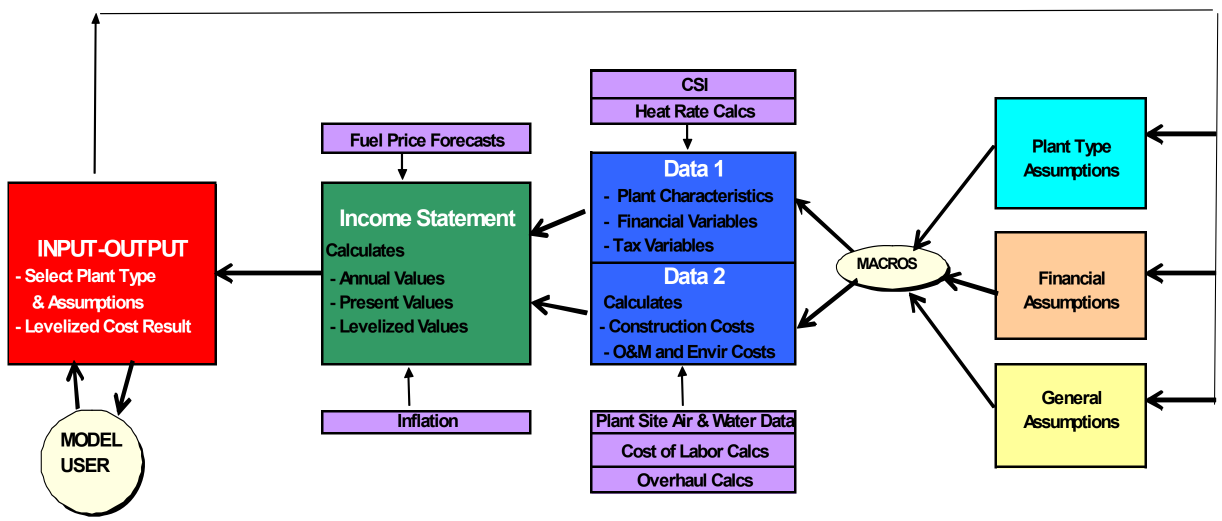
Instructions	General Instructions & Model Description.
Adders	Provides Adder Costs that can be entered exogenously for the combined cycle & simple cycle units.
Input-Output	User selects Assumptions - Levelized Costs are reported along with some key data values.
Data 1	Plant, Financial & Tax Data are summarized - User can override data for unique scenarios.
Data 2	Construction, O&M Costs are calculated in base year dollars.
Income Statement	Calculates Annual Costs and Levelizes those Costs - Shows Annual Cash Flows of Costs & Revenues.
Plant Type Assumptions	Data Assumptions summary for each Plant Type.
Financial Assumptions	Data Assumptions summary of all Financial Data.
General Assumptions	General Assumptions summary such as Inflation Rates & Tax Rates.
Plant Site Air & Water Data	Regional Air Emissions & Water Costs - Used by Data 2 Worksheet.
Overhaul Calcs	Calculates Overhaul & Equipment Replacement Costs - Used by Data 2 Worksheet.
Inflation	Calculates Historical & Forward Inflation Rates based on GDP Price Deflator Series - Used by Income Statement Worksheet.
Fuel Price Forecasts	Fuel Price Forecast - Used by the Income Statement Worksheet.
Heat Rate Table	Shows the regression and provides the Heat Rate factors.
Labor Table	Calculates the Labor Cost components.
CSI	Shows the California Solar Initiative.

Source: Energy Commission

The relationship of these worksheets is illustrated in Figure 21.

One way to better understand the workings of this Model is to visualize the Income Statement Worksheet as the Model, the Input-Output Worksheet as the control module, which also summarizes the results, and the remaining worksheets as data inputs. Data 1 and 2 could be considered to be the data set (broken into two parts) that is derived from the Assumptions Worksheets and the remaining worksheets (auxiliary data).

Figure 21: Block Diagram for Cost of Generation Model



Source: Energy Commission

Input-Output Worksheet

Figure 22 shows the key interface worksheet, where the user selects the generation technology and characteristics, and reads the final result. Through the use of drop down windows, the user selects the power plant type, the financial assumptions, the general assumptions, fuel price and regional location of the power plant. The user enters the start year.

Figure 22: Technology Assumptions Selection Box

Plant Type Assumptions (Select)	**Combined Cycle Standard - 2 Turbines, No Duct Firing**
Financial (Ownership) Assumptions (Select)	**Default-Merchant**
Ownership Type For Scenarios	**Merchant**
General Assumptions (Select)	**Default**
Base Year (All Costs In 2005 Dollars)	**2005**
Fuel	**Natural Gas**
Data Source	*CEC 2007 IEPR Survey (Will Walters, Aspen)*
Start (Inservice) Year (Enter)	**2007**
Fuel Price Forecast (Select)	**CA - Avg.**
Plant Site Region (Air & Water) (Select)	**CA - Avg.**
Study Perspective (Select)	**At Load Center**
Reported Construction Cost Basis (Select)	**Installed**
Turbine Configuration (Select)	**2**

Source: Energy Commission

The remaining options are more complex and require further description. The study perspective sets the location of the calculation (busbar or load center) – that is, the load center option allows for transformer and transmission losses incurred getting to the delivery point. All data reported in this Model are based on load center. The reported construction cost basis allows the user to enter the data as instant or installed. The turbine configuration allows for non-standard configurations for the combined cycle units. The standard configuration is two combustion turbine units and one steam generator – thus the number 2.

The Model collects the relevant data as directed by the selection box and delivers it to the Data Worksheets. The Income Statement then uses the Data Worksheets to calculate the levelized costs and reports those costs back to the Input-Output Worksheet to the Table shown in Figure 23.

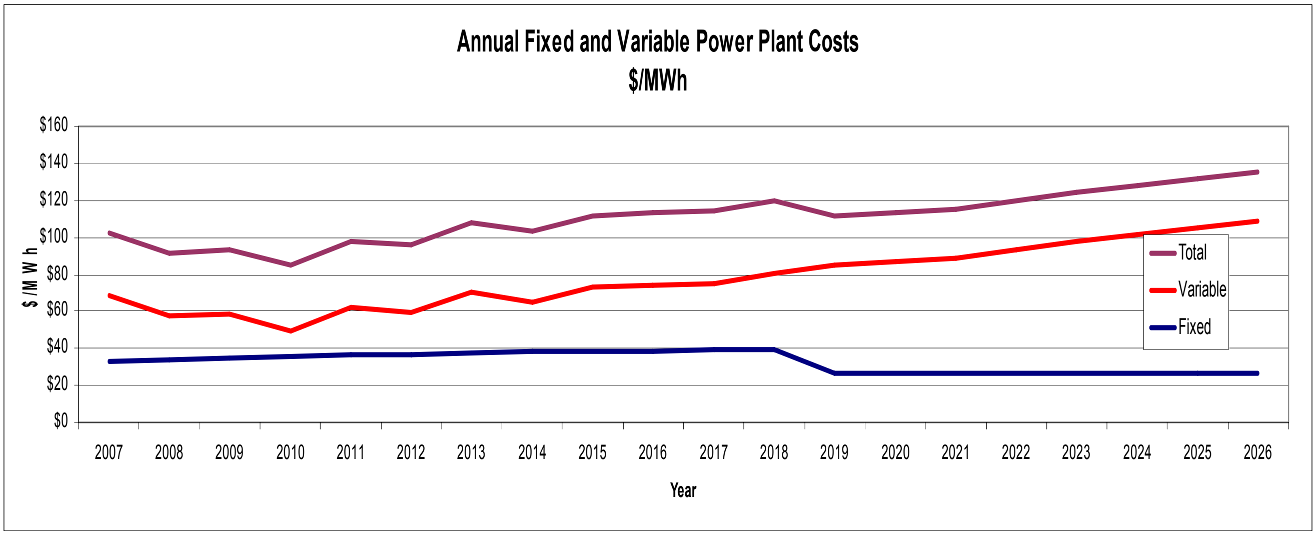
Figure 23: Levelized Cost Output

SUMMARY OF LEVELIZED COSTS Combined Cycle Standard - 2 Turbines, No Duct Firing		
Start Year = 2007 (2007 Dollars)	**$/kW-Yr**	**$/MWh**
Capital & Financing - Construction	$116.08	$22.86
Insurance	$5.77	$1.14
Ad Valorem Costs	$7.37	$1.45
Fixed O&M Costs	$11.58	$2.28
Corporate Taxes (w/Credits)	$38.96	$7.67
Fixed Costs	**$179.75**	**$35.40**
Fuel Costs	$309.45	$60.95
Variable O&M	$26.27	$5.17
Variable Costs	**$335.71**	**$66.12**
Total Levelized Costs	**$515.46**	**$101.53**

Source: Energy Commission

This worksheet also shows the annual costs both tabular and graphically in Figure 24.

Figure 24: Annual Costs



	Levelized	NPV	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Fixed Costs	$34.29	$279	$33.1	$34.0	$34.7	$35.5	$36.2	$36.9	$37.6	$38.2	$38.4	$38.7	$39.1	$39.4	$26.4	$26.4
Variable Costs	$69.83	$569	$68.9	$57.8	$58.3	$49.7	$61.8	$59.1	$70.1	$65.0	$73.5	$74.4	$75.4	$80.2	$85.2	$86.9
Total Costs	$104.12	$848	$102.0	$91.7	$93.1	$85.2	$98.1	$96.0	$107.7	$103.2	$111.9	$113.2	$114.5	$119.6	$111.6	$113.3

Source: Energy Commission

Assumptions Worksheets

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

Plant Type Assumptions – This worksheet stores all of the power plant specific data, such as plant size, fuel use, plant performance characteristics, construction costs, operation and maintenance costs, environmental costs, and water usage costs. There are over 200 of these items, but the most important, at least for thermal units, are the fuel costs (fuel price and heat rate) and capital costs. These account for 70 to 90 percent of the cost of a fossil fueled power plant.

Financial Assumptions - This worksheet stores the capital structure and cost of capital data for the three main categories of ownership: merchant, IOU and publicly owned. The worksheet provides the relative percentages of equity as opposed to long term debt, as well as the cost of capital for these two basic financing mechanisms. It also provides data on eligibility for tax credits.

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

Based on the user selections in the Input-Output Worksheet, the relevant data in these Assumptions Worksheets is gathered by a macro and sent to the Data Worksheets.

Data Worksheets

This is where the macro stores the data selected from the Assumptions Worksheets, and basic calculations are made to prepare data for the Income Statement Worksheet. Data 1 and Data 2 Worksheets can be envisioned as two parts of the main dataset to be used in the Income Statement. These are separated solely to keep the worksheets to a reasonable size. Data 1 and 2 also provide the opportunity for the user to modify or replace the data that came from the Assumptions Worksheets. Care should be taken to modify only those areas that are shaded in color.

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

Data 1 – This worksheet summarizes key data: plant capacity size and energy data, fuel use (such as heat rate and generation), operational performance data (such as forced outage rate and scheduled outage factor, key financial data (such as inflation rates and capital structure), and tax information (such as tax rates and tax benefits). It also does some calculations in order to calculate certain necessary variables. The following sheet sends data to the Data 1 Worksheet.

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

Data 2 – This worksheet calculates construction, operation, maintenance, water use and environmental costs. These calculations depend on data from the following worksheets:

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

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

Keep in mind that all the data in these worksheets are for base year dollars. These costs are used by the Income Statement Worksheet to calculate the yearly values and account for inflation.

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

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

Inflation – This worksheet provides inflation factors used by the Income Statement Worksheet, needed to inflate the various capital and O&M costs. This worksheet calculates two inflation values to simplify the Income Statement calculations: a historical inflation rate, used for the period from the base year to the start year, and a forward inflation rate, used for the period from the start year to the end of the study.

Income Statement Worksheet

This worksheet takes the data from the above data sources and calculates the fixed and variable cost components of total levelized cost. It develops the yearly values, present values and levelized costs necessary for the cash-flow and revenue calculations.

Model Improvements Since *2003 IEPR*

The Model has undergone numerous changes since the *2003 IEPR*, both in model structure and data inputs.

Improvements in User Interface

One of the major intents was to improve the transparency and usability of this Model because it was considered by some to be confusing and at times inscrutable. Toward that end, staff made dramatic improvements in the user interface and developed a comprehensive User's Guide. The following is a delineation of the most significant improvements in this regard:

- **Combined the Many Workbooks into a Singular Workbook with Drop-Down Menus –** The 2003 version consisted of about 25 separate workbooks, one for each technology and two common workbooks (natural gas prices and financial variables). All of these spreadsheets have been reduced to a singular workbook.

- **Improved Documentation in the Model –** Previously, there was very little documentation so that it was difficult to understand the various components and the source of the data. This new version has over a hundred explanatory comments that pop up in response to the cursor.

- **Created a User's Guide –** Previously, there was no written descriptive material. The staff has completed an extensive User's Guide that explains how to use the Model and the Model mechanics. It also provides a definitions section that defines all relevant terminology both in narrative and with formulas.

- **Added the Ability to do Scenarios –** The Model now has the ability to save scenarios for future use. After a technology has been temporarily modified for a specific case, it can be saved with the "Save as New Scenario" button for future use.

- **Added More Detail to Levelized Cost Output –** The levelized costs are now shown in complete detail in both $/MWh and $/kW-Yr.

- **Added Graphical Summary Data –** The levelized costs are shown graphically as well as numerically, which makes it easier to see the relevant importance of the various components of the costs.

- **Added Annual Costs Output –** So that the levelized costs can be better interpreted, the annual costs that produced those levelized costs are shown as an output in both numerical and graphical format.

Improvements in Model Mechanics

The Model's mechanics have also been improved to be more complete, more accurate and more flexible.

- **Ability to Model Both Cash-Flow and Revenue Requirements –** The Model has been modified so that it can emulate IOU, publicly owned and merchant facilities using the appropriate income statement.

- **Added Year by Year Inflation Values –** Previously, the Model used one inflation rate, 2 percent, for all years. This is simplistic and not consistent with the inflation factors used for the fuel price forecast. The Model has been modified to accept year by year inflation factors that are linked forward to the inflation of fuel prices to ensure consistency.

- **Added Real Escalation Factors –** Previously, the Model had only Nominal inflation. The Model now captures both nominal (or general) inflation and real cost escalation for individual components.

- **Incorporated GADS Definitions –** The Model has been modified to incorporate standard NERC/GADS definitions for the reliability and output factors, most notably for scheduled and forced (unscheduled) outage. This is important within itself to ensure standardization of definitions, but can become more important if an attempt to use NERC/GADS data in the future or even attempts to just benchmark Energy Commission values against NERC/GADS data.

- **Modified the Model to Develop Screening Curves –** The cost of generation Model is limited in its ability to compare one generation against another because it uses a singular assumed capacity factor for each technology. This is a serious limitation. This feature, its importance and its limitations are described in a separate section below.

- **Corrected the Definitions for Capacity Factor and Availability Factors –** The definitions of capacity and availability factors in the old model were simply wrong and inconsistent with common practices at the Energy Commission. This is important in itself, but becomes essential when the Model is used to create screening curves.

- **Improved Heat Rates–** Since fuel cost can be as much as 80 percent of the levelized cost for a combined cycle unit, it is important to have accurate heat rates. The heat rates in the Model have been improved to reflect actual operation rather than manufacturer estimates. Energy Commission staff used actual QFER fuel consumption and electric output data to develop heat rates to reflect actual operation.

- **Miscellaneous Improvements in Calculations –** Improved the calculation of installed cost, WACC, taxes, depreciation, and ad valorem.

Improvements in Data Inputs

Most of the data in the Model has been updated:

Power Plant Data – All power plant cost data has been revised through data requests to reflect actual as-built data.

Natural Gas Prices – The Model has been updated to reflect the Energy Commission's most current forecast. It also provides optional forecasts.

Inflation Values – Inflation factors have been updated.

Tax Rates, Tax Deductions and Tax Credits – These variables were reviewed and updated as necessary.

Capital Structure – Cost of equity and long term debt were updated along with the debt to equity ratios, discount rate and weighted average cost of capital.

Degradation Factors – Heat rate degradation factors have been added.

Model Limitations

Models are inherently limited because a number of assumptions must be made for each generation technology. The most important assumptions are:

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

Capital Costs

Deriving capital costs is challenging, particularly for alternative technologies since costs tend to drop with increased development over time. Even for well developed technologies, such as combined cycle and simple cycle plants, it is difficult because of varying location and situational costs. Developers generally keep this information confidential to maintain a competitive edge over other developers.

Fuel Costs

Fuel cost is highly unpredictable and difficult to forecast with a high degree of accuracy. The only safeguard against the unpredictability of fuel cost forecast is to have alternative forecasts for comparison and to use uncertainty analysis. The Model thereby has the ability to compare the implications of different forecast.

Capacity Factors

Models are inherently limited because the user must assume a specific capacity factor, which may or may not be applicable to the power plant under consideration. This is a common problem for combined cycle and simple cycle power plants. Combined cycle units are all too commonly modeled as having capacity factors in the range of 90 percent, but the historical information on California power plants, as summarized in Table 30**,** shows that the average is closer to 60 percent or less. The staff Model attempts to deal with this problem with the screening curve function, as described below.

Table 30: Actual Historical Capacity Factors

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

Source: Energy Commission

Heat Rates

An actual thermal power plant being considered, such as a combined cycle unit, may operate at an entirely different capacity factor than that selected for the Model. In fact, these plants typically operate at different capacity factors from month to month and even day to day. These varying capacity factors result in differing heat rates. A combined cycle unit has most efficient (lowest) heat rate at full power, or in the case of a duct-fired plant, at near full power since the duct-firing process provides additional power at the cost of lower efficiency. Operation at lower power levels produces less efficient operation (higher heat rates). Two identical power plants with the same capacity factor can have widely different average annual heat rates. For example, both could have 50 percent capacity factors if one operated at full power for half of the year and the other operated at half power for the entire year. Obviously, the latter unit would have a much higher heat rate. The staff Model attempts to deal with this problem with the screening curve function, as described below.

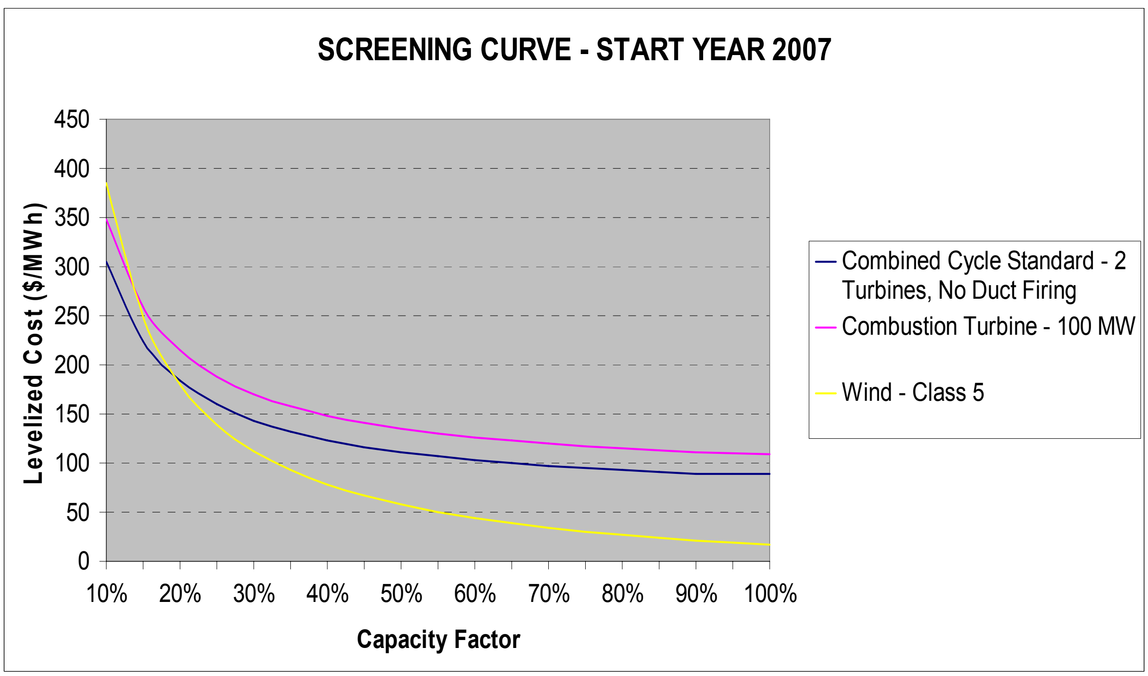
Model's Screening Curve Function

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

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

The levelized cost can be shown as $/MWh or $/kW-Year. Figure 25 is an illustrative example of a $/MWh screening curve.

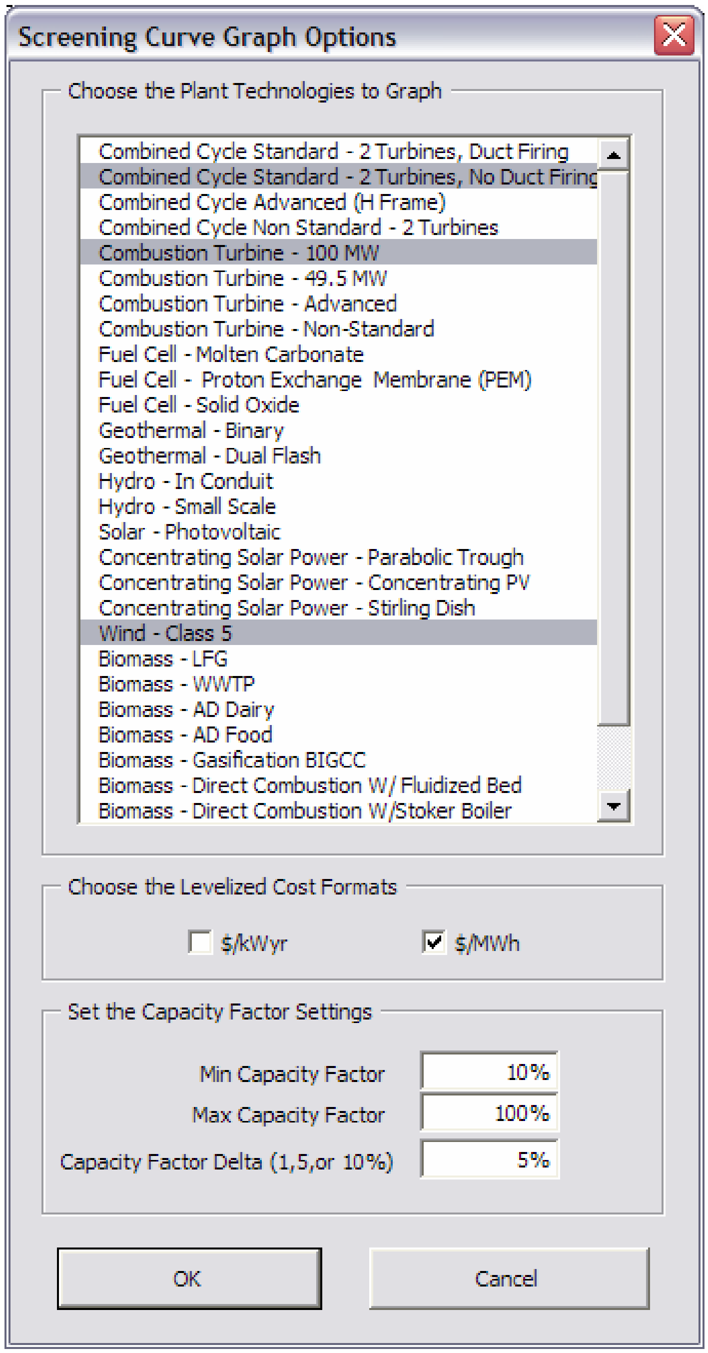
Figure 25: Screening Curve in Terms of Dollars per Megawatt Hour



Source: Energy Commission

Figure 26 shows the corresponding interface window.

Figure 26: Interface Window for Screening Curve



Source: Energy Commission

Misuse of Screening Curves

Care must be taken to not misuse the screening curves. The curves only estimate the relative costs. This is a good starting point, which is why they are called "screening curves." For those cases where costs are close, additional and more detailed economic analysis is necessary.

It is also essential to use these curves in proper perspective. If the study is to simply compare the costs, the screening curves are useful. If the study is to determine the least cost to the system where the unit will be operating, then the screening curves are of less value and should be very carefully applied.

First of all, the assumed capacity factor is just that, an assumption. The actual capacity factor will depend on its economic viability once it is actually operating in the system. Furthermore, that capacity factor will vary over the seasons of the year, and from year to year. In addition, screening curves do not reveal how a unit will affect the system operations. This is where a production cost or market model becomes important since they can capture these kinds of interactions. A production cost or a market model can emulate the system, how the generation unit will operate and how the unit will likely affect the rest of the system. Different generation technologies offer different system attributes and services.

All of this, however, ignores environmental, risk and diversity factors which may in the final analysis be the determining factors.

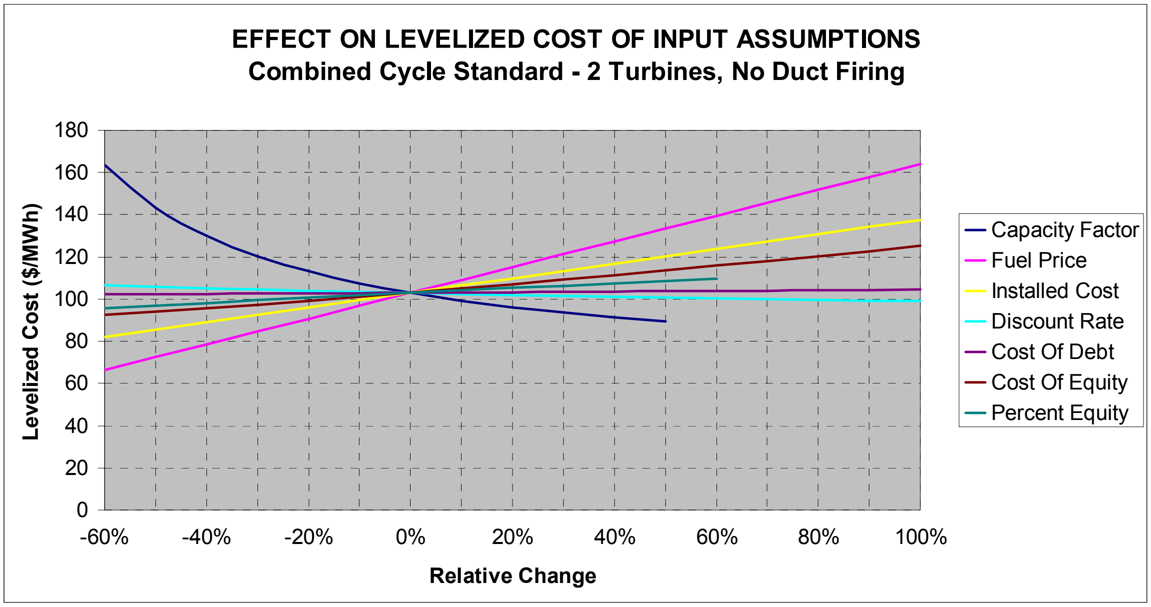
Model's Sensitivity Curve Function

Although the above discussed screening curves can prove useful, they address only one variable to the base case assumptions when estimating levelized costs – the capacity factor. Staff's new sensitivity curves address a multitude of assumptions: capacity factor, fuel prices, installed cost, discount rate (WACC), percent equity, cost of equity, cost of debt, and any other variable that should be considered. Sensitivity curves show the effect on total levelized cost by varying any of these parameters in three formats:

- Levelized Cost ($/MWh or $/kW-Year)
- Change in Levelized Cost as a percent
- Change in Levelized Cost as incremental levelized cost from the base value ($/MWh or $/kW-Year).

Figure 27 shows an illustrative example of a sensitivity curve.

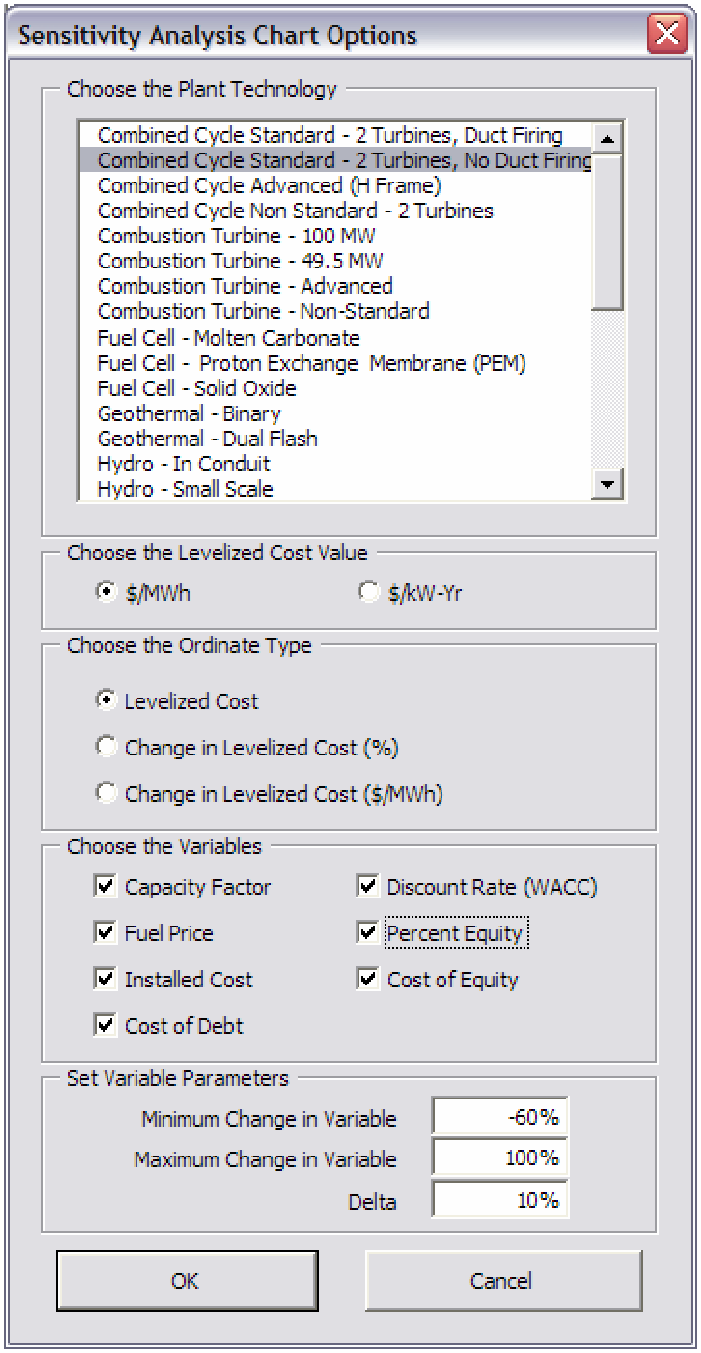
Figure 27: Sample Sensitivity Curve



Source: Energy Commission

Figure 28 shows the interface window for the above sensitivity curve.

Figure 28: Interface Window for Screening Curves



Source: Energy Commission

Estimating Wholesale Electricity Prices

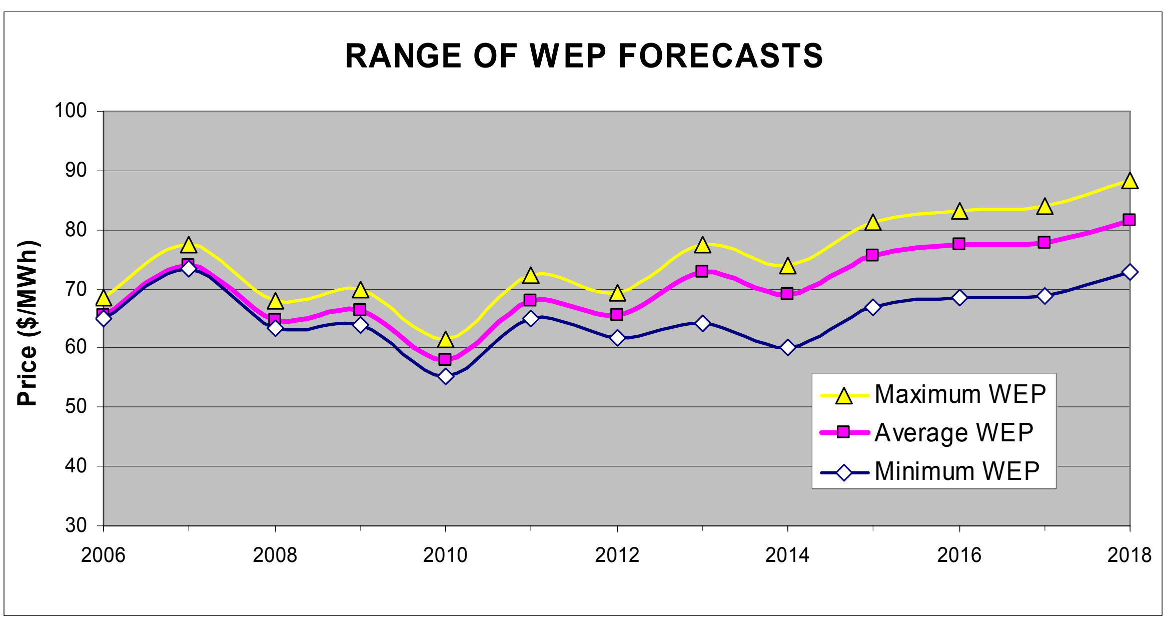
The Model can be used in conjunction with the Marketsym model – or some other production cost model – to forecast wholesale electricity prices. The Model can calculate the fixed cost portion of the wholesale electricity prices but not the variable portion. The Marketsym model, on the other hand, can calculate the variable portion of the WEP, but not the fixed portion.

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

The Marketsym model is run in the cost-based mode for all the years of the forecast using all the above identified resource additions. The fixed costs from the Model are then added to the variable costs from the Marketsym model to get the WEP forecast.

Figure 29 is an illustrative example of the resulting wholesale electricity price forecast. The maximum wholesale electricity price is the most expensive generating unit in each year. The minimum wholesale electricity price is the least expensive generating unit in each year. The average wholesale electricity price is the average of all the generating units operating in that year.

Figure 29: Illustrative Example for Wholesale Electricity Price Forecast



Source: Energy Commission

APPENDIX A: CONTACT PERSONNEL

The following is a list of the Energy Commission and contractor personnel who participated in the development of the Model, the data gathering process and the computer simulations, along with their phone numbers and e-mail addresses. This list is intended to facilitate your information requests related to this report. If you are in doubt as to whom to contact, you can contact the authors, who will direct you to the appropriate source. Copies of this report, as well as Model and its User's Guide are available on the website at:

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Source: Energy Commission