Levelized Cost of Electricity Associated With Out-of-City Renewable Energy Resources Considered Supply Candidates for the City and County of San Francisco CCA Program (Task 3 of 5)

(DRAFT REPORT)

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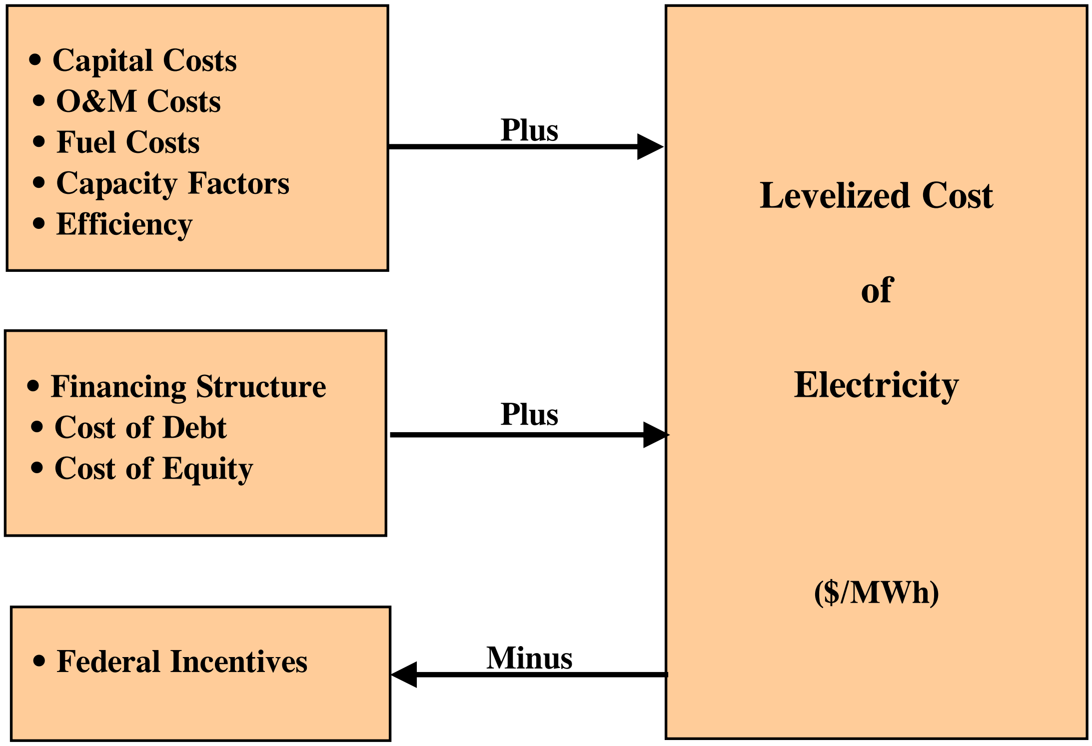
1.1 Overview

George E. Sansoucy, P.E., LLC (GES) was retained by the San Francisco Public Utilities Commission (SFPUC) to prepare a report on the levelized costs of renewable energy resources located beyond the jurisdictional boundaries of the City and County of San Francisco (CCSF). The purpose of the analysis is to assess the potential benefits associated with resources located outside of the CCSF. These resources could then be either contracted for utilizing power purchase agreements (PPAs) or owned by the Community Choice Aggregation (CCA) program to serve its customers in the CCSF.

This Task 3 report analyzes the out-of-city Levelized Cost of Electricity (LCOE) associated with commercially available renewable energy resources that are considered reasonable candidates for serving CCA customer load. The LCOE for each resource was developed utilizing analyses and technologies identical to the Task 2 report on the LCOE of in-city resource options based on two ownership structures. The first scenario assumes for-profit ownership with the electricity being delivered to the CCA program via a PPA. The second scenario assumes the renewable resources are owned by not-for-profit entities using H Bonds or other forms of tax exempt revenue bonds. The for-profit scenario allows the owner/developer to utilize all incentives available at the federal level through the U.S. Tax Code. The LCOE, for the purposes of this analysis, is defined as the cost per unit of electricity required to recover the invested capital, cover annual operating and maintenance (O&M) expenses, and provide debt and equity investors their respective rates of return.

Figure 1-1 is an illustration of the LCOE components relative to the annual costs associated with each increment of electricity as measured in dollars per megawatt-hour ($/MWh). The LCOE includes all the fixed and variable costs of operation, taking into consideration the effect of federal and State tax incentives and revenue required to support the capital investment.

Figure 1-1
Levelized Cost of Electricity (LCOE) Components



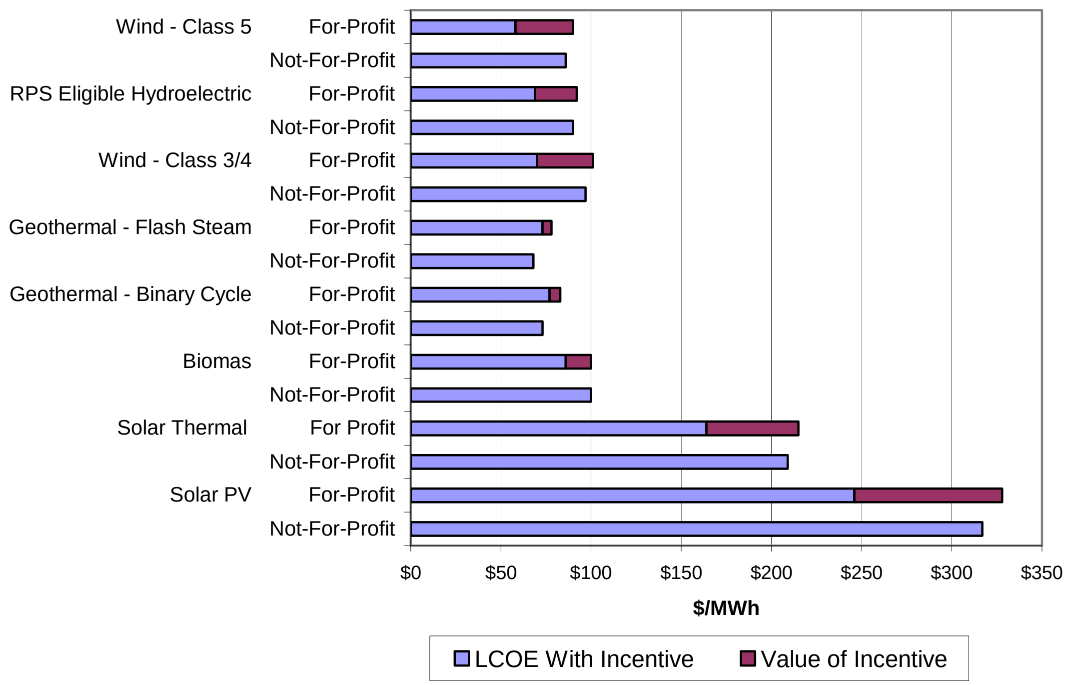
The levelized costs set forth in this report correspond to the levelized cost model set forth in Figure 1-1. A full discussion of these components and the scenarios under which the LCOE was calculated is provided in Section 3.

1.2 Levelized Cost of Electricity (LCOE)

The LCOE associated with out-of-city resources was developed using spreadsheet models developed by GES and are similar to those utilized in our Task 2 report on the LCOE associated with in-city resources. A separate model was developed for each resource using both for- and not-for-profit owners. The model calculates the LCOE of each renewable resource based on resource-specific cost and operating data and market-based assumptions about financing, federal and State tax liability or benefits, and other incentives available to each technology. The for-profit model minimizes the LCOE over a 20-year period while maintaining debt financing requirements and equity returns necessary to satisfy investor requirements. The not-for-profit model develops the LCOE over a 20-year period by calculating the revenue requirements associated with each project assuming 100% debt financing and no federal or State income tax benefits or liability.

The results of each analysis are set forth in Figure 1-2. A discussion of these results and specific assumptions is provided below for each resource category.

Figure 1-2
Levelized Cost of Electricity (LCOE)
Including Incentives and LCOE Without Incentives
With No Transmission Costs to the CCSF
(in ascending order by For-Profit)



The results range from a low of approximately $60/MWh to a high of over $300/MWh and indicate that wind, Renewables Portfolio Standard (RPS) eligible hydroelectric,[1] and geothermal resources are the least cost while solar is among the highest. The primary reason for the high cost of solar is its high capital cost, on a $/kW basis, relative to the anticipated low electrical output of the project.

If additional generation was produced by these units, it would lower the LCOE on a megawatt-hour basis. However, since these resources are limited by the amount of available natural resources and the ability to utilize this resource the LCOE is higher than alternative renewable projects.

The lowest LCOE is typically accomplished utilizing a for-profit ownership structure with energy sold to the CCA via a PPA. This type of structure typically provides the lowest price of electricity because the subject resource qualifies for federal incentives provided through the U.S. Tax Code. This is clearly the case for most of the resources addressed in this report.

[1] Renewables Portfolio Standard (RPS) eligible hydroelectric refers to installations that satisfy State guidelines for the RPS. These are discussed in Section 4.

2.1 Introduction

The San Francisco Public Utilities Commission (SFPUC) has retained George E. Sansoucy, P.E., LLC (GES) to prepare this Task 3 report on the levelized cost of out-of-city renewable energy resources that could be developed as resource options for the Community Choice Aggregation (CCA) program. This report is intended to assist the SFPUC in assessing the potential renewable resources available outside of the City and County of San Francisco (CCSF) and potential supply resources for its CCA program. This program calls for either the CCSF or its Energy Service Provider (ESP)[2] to develop 360 megawatts (MW) of renewable, distributed generation or energy efficiency measures to be included as part of the supply mix serving customer loads, with approximately 210 of the total 360 MW to be located within the jurisdictional boundaries of the CCSF.

Purpose and Use of Report

- This report investigates the levelized cost associated with out-of-city resources as a component of the 51% Renewables Portfolio Standard (RPS).
- Prior reports addressed in-city renewable resources and the potential economic impact on the CCA program.
- A subsequent report will address the cost of the resource mix necessary to satisfy CCA customer demand.

This report (Task 3) is the third in a series of five reports and will address the out-of-city feasibility, cost, and rate consequences of the 210 MW of specified resources and the 51% renewable energy requirements by 2017. The previous and subsequent tasks are summarized as follows:

- Task 1 included the theoretical and technical potential for renewable resources within the CCSF.
- Task 2 included the economic potential of those resources considered theoretically and technically viable within the CCSF. This task addressed the cost of these resources to CCA program customers using the estimated capital cost, O&M expense, and financial incentive for each of the resources selected and analyzed the use of for-profit and not-for-profit capital structures and financing.
- Task 4 is a comparison of the information and costs developed in Tasks 1 through 3 relative to whether these resources are cost effective and allow the

[2] An ESP is an individual or company that contracts directly with its customers to provide electric supplies. ESPs may serve only selected markets, such as large commercial and industrial customers, or all customers including residential.

CCA program to "meet or beat" Pacific Gas and Electric Company's (PG&E) expected rates for CCA program customers.

- Task 5 is a report setting forth any recommendations that could enhance the CCA program based on the investigations and analyses set forth in Tasks 1 through 4.

2.2 CCA Program Resource Requirement

The implementation of the CCA program will require that, among other things, sufficient electric resources are available to serve the program customers. PG&E will no longer be responsible for supplying the resources necessary to serve the customers that are part of the CCA program, but will be responsible for the transmission and distribution of the electricity as well as meter reading and billing. The expectation is that the CCA program supply mix will utilize a wide range of renewable and non-renewable resource options to ensure that the electrical supply is reasonably priced, reliable, and meets the criteria set forth by the CCA program directives.

2.3 Scope of the Analysis

The scope of this report is to provide an economic analysis of renewable energy resources that could be developed outside of the CCSF jurisdiction as part of the CCA program based on the Levelized Cost of Electricity (LCOE) associated with each resource. This report analyzes the LCOE for various out-of-city resources that are capable of being developed in the State of California (State). The LCOE for each resource under for- and not-for-profit ownership structures was used to identify the LCOE necessary to justify development of these resources.

The method of analyses applied in this report is the same as that employed in the Task 2 report to address the LCOE of in-city renewable resources. The economics of each ownership structure are discussed below and are dependent on the level of incentives available to for-profit entities relative to comparable incentives for not-for-profit entities. As the level of incentives increase, the ability for not-for-profit owners to provide equally economic electric prices diminishes. This is due primarily to the bulk of the incentives for renewable resources being provided through the U.S. Tax Code which only benefits entities paying federal income tax.

The LCOE associated with each out-of-city renewable resource is calculated using a Microsoft Excel spreadsheet model that identifies the revenues necessary to recover invested capital, cover annual operating and maintenance (O&M) expenses, and provide debt and equity investors their respective rates of return. The models are different for each ownership type to account for the financing structure and incentives available. Over a 20-year period, the LCOE associated with each ownership structure is used to assess the economic potential of the renewable resources in the CCSF.

In performing the LCOE calculations under the two ownership structures, current market and resource-specific assumptions were utilized as model inputs for items such as inflation, current federal and State incentives, and cost of debt and equity. These assumptions, along with those developed for each technology, are set forth in Section 3 of this report.

2.4 Report Organization

The report is organized into the following sections.

- Section 3.0 Methodology and Assumptions

  This section describes the general approach employed in this report, the extent of the information gathered, technologies analyzed, and methodology and general assumptions. This section provides the initial resource screening and a discussion of generic characteristics and assumptions relative to each of the selected resources.

- Section 4.0 Resource Summary

  The resources selected as part of this Task 3 report are set forth and include the following:

  - Large-scale solar PV installations (5 MW or larger)
  - Solar thermal installations consisting of parabolic trough technology
  - Land-based Class 3 through 5 wind locations
  - Renewables Portfolio Standard (RPS) Eligible Hydroelectric
  - Geothermal (Flash Steam and Binary Cycle System) resources
  - Biomass-fired generating resources

- Section 5.0 Levelized Cost of Electricity Model

  The LCOE for each resource is set forth in this section along with a least cost ranking of the various resources considered feasible.

- Appendix A and Appendix B

  The appendices to this report set forth the calculations utilized to develop a 20-year LCOE for each resource identified in the Task 1 report for both ownership structures.

3.1 Introduction

The renewable resources selected for inclusion in this report were those considered commercially viable and feasible to construct in California. In determining which technology to analyze, consideration was given to all renewable resource categories which include solar, hydroelectric, hydrokinetic, geothermal, biomass and wind. The resources considered for inclusion in this report are generic resources reasonably available to the CCA program and include the following:

Out-of-City Renewable Resources Considered In This Report

- Large-scale Solar PV (5 MW or larger)
- Solar Thermal (Parabolic Trough)
- Land-based Wind (Class 3 through 5)
- Renewables Portfolio Standard (RPS) Eligible Hydroelectric
- Geothermal (Flash Steam and Binary Cycle Systems)
- Biomass-fired

- Large-scale solar PV installations (5 MW or larger)
- Solar thermal installations consisting of parabolic trough technology
- Land-based Class 3 through 5 wind locations
- Renewables Portfolio Standard (RPS) Eligible Hydroelectric
- Geothermal (Flash Steam and Binary Cycle System) resources
- Biomass-fired generating resources

The analysis did not consider out-of-city fossil resources as this was beyond the scope of this analysis and, to the extent considered in the CCA program, will be addressed in the Task 4 report. The Task 4 report will address the overall CCA program supply mix and corresponding cost of electricity.

3.2 Initial Resource Screening

The initial screening process considered the commercial availability of each technology. Commercially available typically means that several of the units or systems have been deployed and are readily available in the marketplace. Renewable resource technologies that are only in the testing or demonstration phase and not considered mature were excluded from this report. The screening for commercial availability eliminated evolving technologies such as wave or hydrokinetic[4] and offshore wind[5] projects as none of these technologies have been deployed commercially in North America.

[4] An example of the difficulties associated with wave power are illustrated by the abandonment of the Pelamis project in Portugal that was sinking due to technical problems. Source: http://cleantech.com/news/4276/pelamis-sinks-portugal-wave-power-p

3.3 General Resource Characteristics

The following generic project characteristics and economic requirements were considered for each technology.

3.3.1 Resource Capacity

The units of measure associated with electricity supply resources are typically kilowatt (kW) or MW, and sometimes watts, and represent the maximum output of a resource.

In presenting information in this report on various generic technologies, every effort was made to use consistent units of measure, such as kW or MW, within the sections to allow for easier comparisons. However, due to the large magnitude of some estimates in certain instances, the units of measure were changed for ease of presentation. Therefore, the following descriptions are set forth to assist the reader in understanding the relationship of the electrical measure of a unit's output.

The basic measure of electricity is a watt and in this report refers to an alternating current (AC) watt unless indicated otherwise. An example of a watt would be a light bulb which uses 100 watts. In measuring larger units of electric demand or supply, kilowatts are typically used and represent 1,000 watts. An example of a kilowatt would be enough electricity to operate ten 100 watt light bulbs. In the CCSF, a typical residential electric account requires a little over 1 kW to serve its load. A medium-sized commercial account would require approximately 50 kW of electric capacity to serve its electric demand.

In measuring larger amounts of electrical capacity, MW is used and represents 1,000 kW. Units such as MW are used in estimating larger electric loads, such as the CCA program's anticipated load which is expected to exceed 750 MW (equal to 750,000 kW or 750,000,000 watts). This illustration is an example of why units are sometimes changed for ease of presentation due to the magnitude of the numbers being discussed in each section.

The net output for electric systems is based on manufacturer ratings of the generator equipment after losses associated with operation and is quoted in AC watts. These ratings assume a typical installation and will vary based on site-specific conditions and equipment installation.

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[5] Since 2008, the Federal Energy Regulatory Commission (FERC) has issued preliminary permits for six California offshore wind projects but none are currently operational. Source: http://www.ferc.gov/industries/hydropower/Indus-act/hydrokinetics.asp.

3.3.2 Capacity Factor

The capacity factor represents the ratio of estimated output from a generating resource over a period of time relative to the output it would have produced had it operated at full output during this same time period. In this report, the period of time is estimated at one year, or 8,760 hours, and the generating output is the system's net output available to satisfy demand. The formula for calculating the capacity factor is shown as follows:

$$\frac{Actual\ or\ Estimated\ Output}{(Net\ Capable\ Output\ x\ 8{,}760\ hrs/yr)} = Annual\ Capacity\ Factor\ (\%)$$

A sample capacity factor calculation is a 1 kW solar PV installation that produced 1,577 kWh of electricity over the period of one year for consumption in a residential unit. The capacity factor for this system would be calculated as follows.

$$\frac{1{,}577\ kWh}{(1\ kW\ \ x\ 8{,}760\ hrs/yr)} = 18\%\ Capacity\ Factor$$

Since no unit is capable of operating 100% of the time due to maintenance requirements, lack of natural resources, or lack of market demand, each resource will have a different expected capacity factor. These are provided for each generic technology identified based on resource availability and the system's technical requirements.

3.3.3 Generation Characteristics

The generation characteristics set forth for each resource include its expected duty cycle in meeting electric demand and includes categories for base load, intermediate or cycling units, peaking units, or units that are intermittent and cannot store a fuel source and are provided for each resource to allow for comparisons between the technologies and the type of load each might serve in the CCA program supply mix.

In addition to the duty cycle, units are characterized based on whether the technology is mature or evolving. This provides insight as to expected market penetration and potential improvements in either efficiency or the costs set forth for each technology as evolving technologies will tend to decline in price in response to greater market demand and increased competition.

3.3.4 Construction Period

The estimated construction period provides an indication of lead time necessary for installation of various technologies. These estimates take into consideration the period of time from project conception to commercial operation. The estimates are based on reasonable forecasts using past experience with the construction period required for similar projects. Construction period will typically increase relative to a project's size and complexity.

3.3.5 Overnight Costs versus Installed Costs

The capital cost for each technology is based on average overnight costs for typical installations and expressed in 2009 dollars (2009$). Overnight costs do not include any interest, inflation, or other carrying costs and assume the project was constructed overnight with no consideration for actual construction periods. The prices are typically expressed in dollars per kilowatt. If an alternative unit is utilized, an explanation is presented for the variation. Costs include permitting, equipment installation and interconnection, and are reasonable estimates of typical installation costs.

An Interest During Construction (IDC) factor was developed to account for the cost of money used to fund the project during construction and added to the overnight cost. The IDC factor was based on the Task 2 report and includes an adder of 7% for a project constructed by a for-profit entity and 5% for a not-for-profit.

3.3.6 Transmission Costs

The renewable resources considered in this report are located outside the CCSF and will incur costs associated with transportation or "wheeling" the output from the project to the CCSF. The cost of the wheeling is based on generic projects and the current costs charged for the use of the California electric transmission system. The amount of wheeling added to each project is discussed in the Task 4 report which compares a total portfolio cost.

3.4 Incentives for Renewable Resources

There are a number of economic incentives available for the installation and operation of renewable energy technologies. These incentives and rebates are offered by federal and State government to promote the construction of renewable technologies that otherwise would not be viable in a competitive market. The following discussion provides a brief overview of the incentives and rebates available to developers and owners.

There are three levels of incentives available for renewable energy projects which include federal, State, and local. In calculating the LCOE for each resource, it is assumed that the resource ownership structure would qualify the resource to take advantage of these incentives. The projects in this report are used primarily for delivery of electricity at the wholesale level and are considered to only qualify for federal incentives.

3.4.1 Federal Incentives Specific to Renewables

The federal incentives for renewable energy are primarily offered through the Internal Revenue Codes in the form of tax deductions such as accelerated depreciation, tax credits, or more recently the ability to receive grants and loans for renewable energy. The major incentives include 26 USC § 45 - Production Tax Credits (PTC), § 48 Investment Tax Credits (ITC), and § 168 Accelerated Depreciation.

Investment Tax Credits and Grants

The American Recovery and Reinvestment Act of 2009 (ARRA-2009) provides for the expansion and extension of several tax-related renewable energy provisions. In lieu of taking the PTC or ITC, eligible taxpayers may apply for grants to the Secretary of the Treasury for a non-discretionary grant of between 10 and 30% of the cost associated with an eligible project. The grant is not subject to federal tax, but the basis of the project is reduced by 15%. Construction must commence during 2009 and 2010 and the project must be in commercial operation before the date the eligible ITC expires.[6]

These grants are in lieu of PTC available under § 45, which allows for an income tax credit ranging from 1 to 2.1¢/kWh for eligible renewable energy resources. These payments escalate and are for a period of 10 years after the date the facility is placed in service. The in-service deadlines are as follows:[7]

[6] http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US53F&State=federal&currentpageid=1&ee=1&re=1.

[7] Ibid.

- January 1, 2013 for wind
- January 1, 2014 for biomass, landfill gas, trash, qualified hydropower, marine and hydrokinetic
- January 1, 2017 for fuel cells, small wind, solar, geothermal, microturbines, combined heat and power (CHP), and geothermal heat pumps

Accelerated Depreciation

Section 168 contains a provision for Modified Accelerated Cost Recovery System (MACRS) which allows for the investment in eligible resources to be recovered through accelerated depreciation deductions. The program has no expiration and eligible resources qualify for 5-year 200% declining-balance depreciation.[8]

Clean Renewable Energy Bonds (CREBs)

CREBs may be used by certain entities in primarily the public sector to finance renewable resources. The resources are generally the same as those which qualify for PTCs. CREBs may be issued to governmental entities, electric cooperatives, and certain lenders. The loan is issued with a zero percent interest rate and the bond holder receives federal tax credits in lieu of interest.

Participation in the program is limited by the volume of bonds allocated by Congress for the program. Participants must file with the IRS for a CREB allocation and then issue the bonds within a specified time period.

The incentives associated with each of the technologies considered in this report will be used to analyze the economic potential of each supply resource. In addition, in cases where there are declining benefits, the current incentives are used in the models for purposes of calculating the LCOE.

3.5 Levelized Cost of Electricity (LCOE)

The renewable energy resources identified in this report have three primary economic drivers that determine the cost competitiveness of each relative to alternatives in the marketplace. These include 1) the capital necessary to install the resource, 2) the O&M costs, including fuel, necessary for the resource to produce electricity, and 3) federal incentives that promote development of renewable resources. In addition to these primary drivers, renewable resources are subject to the same market forces as other electric resources which include the availability of credit, the cost of debt and equity financing, demand for new capacity, and availability of technology and resources.

[8] Ibid.

These economic drivers were incorporated into an analysis for each renewable resource and used to calculate a 20-year LCOE. The LCOE estimates are industry standard calculations used to assess electric resources and provide a first level of screening among several technologies or unit sizes in the economic selection of supply resources. The constant price each resource must receive over a 20-year period to justify the resource can be compared against the 20-year LCOE of other resources or against market prices to determine the economic potential of a particular resource. These are developed in Section 5 of this report and utilize inputs similar to the Task 2 report.

3.6 Capital Structure and Financing Assumptions

The capital structure and financing assumptions are unique to each form of ownership and renewable resource. The capital structure refers to the amount of debt and equity utilized to fund ownership of the project. The cost of each type of capital is market-based and reflects current market requirements for attracting each type of capital. The estimates used take into consideration the resource's use as part of the CCA program which is anticipated to lower the overall risk. The capital structure and associated cost of financing each type of capital is dependent on several factors that include 1) ownership structure, 2) cash flow available for debt service, and 3) risk of the project.

3.6.1 For-Profit Capital Structure

The for-profit capital structure includes the use of both debt and equity capital to finance the ownership of renewable resources. In both instances, these financing options are taxable and require higher returns than under not-for-profit ownership.

In financing the project with debt, the cash flows available to satisfy these obligations must meet requirements set forth by various financial institutions. In general, entities providing debt financing will require debt service coverage ratios (DSCR)[9] of between 1.2x and 1.8x cash flow. This range is based on a review of the financing term for several renewable energy projects and our experience with the valuation of resources for financing and other purposes.

The financial models in this report structure the debt to reflect the project's ability to satisfy a specified DSCR in each year of the analyses. The remainder of the project is financed utilizing equity. The 1.2x DSCR selected was the lowest possible ratio that could be used for financing purposes without additional guarantees or additional funds established to assure debt service payments.

[9] Debt Service Coverage Ratio (DSCR) is the ratio of net operating income to annual debt service and measures the ability of a property to meet its debt service obligation out of operating income.

Typical equity rates for use in financing renewable resources are 12 to 18% after-tax without situations which lower the risk of the project. An after-tax rate of 12% was selected as representing a reasonable project rate of return for equity invested in this type of project.

The 1.2x DSCR and the 12% cost of equity are both at the low end of the range for merchant generating facilities. This is considered reasonable due to the use of the resources in the CCSF CCA program which lower the project's risk and increases its ability to receive attractive financing. Therefore, if the financing was for merchant purposes with a sale into the California electric market, the DSCR and cost of equity would most likely be higher to reflect this additional risk.

3.6.2 Not-For-Profit Capital Structure

In estimating the LCOE for a not-for-profit entity such as the CCSF, the CCA program, public utility, or similar quasi-governmental entity created to own the generation on behalf of the CCA program, a financing structure of 100% debt is used, which is typical for this type of ownership as long as the use of the project meets the public purpose provisions of the IRS rules. The cost of not-for-profit debt is typically lower than for-profit debt as it is tax exempt. In the case of the potential CCA resources, a tax exempt debt rate of 5% is considered reasonable and used in the pro forma models to estimate the debt costs and the LCOE. This cost of debt assumes H Bonds or similar forms of financing and that the project meets the financing requirements necessary to utilize tax exempt financing.

Table 3-1 summarizes the financial assumptions utilized in calculating levelized costs of energy. These financing assumptions are consistent with current market expectations and assume typical developer and/or merchant ownership credit worthiness and project finance with a contact to the CCA program.

Table 3-1
Capital and Financing Assumptions

	For-Profit	Not-For-Profit
% Debt	40-60%	100%
% Equity	60-40%	0%
Cost of Debt	7.0%	5.0%
Cost of Equity	12%	N/A
Debt Term (years)	20	20

3.7 Ownership Structure Model

3.7.1 For-Profit Ownership Structure

The for-profit ownership structure assumes that the project will be owned and operated by one or more for-profit entities that utilize a PPA to provide power to the CCA program. The three ownership structures consist of 1) a sole corporate owner, 2) a partnership "flip" structure, or 3) operating lease of same kind. The benefits of each structure will vary by project, but each is designed to maximize benefits while lowering the LCOE.[10]

In calculating the LCOE, no particular structure was assumed but the benefits that arise from each was incorporated into the LCOE by assuming that the owner could utilize all the benefits which flow from the U.S. Tax Code and that the credit worthiness of both the CCA program and the developer assured reasonable debt and equity rates for the projects.

The for-profit model used to calculate the LCOE for each project was developed in Microsoft Excel. The model utilizes user-defined inputs, internal formulas, and the Excel Solver function to minimize the 20-year LCOE for each renewable energy project while satisfying the targeted Internal Rate of Return (IRR) for equity investors and the minimum DSCR necessary to finance each resource based on available cash flows generated through the sale of power. The model assumes equity investors can utilize all associated tax benefits and calculates the amount of project leverage based upon a predetermined DSCR typically required to obtain financing. The inability of the owner to utilize all of the tax benefits in the year incurred has the potential of changing the results and increasing the LCOE associated with each project. In addition, changes in the level of benefits available through the U.S. Tax Code, or other incentives, will result in a different LCOE than those presented in this report.

The assumptions for each project are set forth on the first page of the spreadsheet and consist of three general categories which include 1) Project, 2) Financial/Economic, and 3) Incentive assumptions. These assumptions are shown in the shaded cells and require user inputs. The LCOE estimates for each resource are based on information in Section 4 of this report relative to each resource.

The pro forma for each project is shown on the second page of the spreadsheet and shows the financial calculations that determine the LCOE. These figures are developed by the model utilizing the underlying formulas and Excel Solver function which minimize the LCOE while satisfying the project's debt and equity requirement. The worksheet for each project was developed by using reasonable assumptions. Input assumptions that exceed reasonable market expectation may result in the model failing to find a solution or require that the user manually change the first year PPA price until an optimum solution is found that satisfies all of the project's financial assumptions. This was not

[10] In addition to these structures, there are several more that utilize one or more of these general structures to create complex ownership and financing arrangements which may include municipal prepayment for power, certain guarantees or other entities providing debt and equity to the deal in order to lower borrowing costs and improve the economics. However, for purposes of calculating the LCOE, those additional structures were not analyzed as each would be both project- and owner-specific.

necessary for any of the resources in this report, but may occur for less mature technologies or assumptions that exceed reasonable parameters.

3.7.2 Not-For-Profit Ownership Structure

The not-for-profit structure assumes a tax-exempt entity owns the resource and utilizes H Bonds or other forms of revenue bonds to finance the capital costs. The structure assumes that the owner is capable of gaining access to low cost financing at the project level and that no other funds or obligations are utilized to lower the interest rate. In addition, no income taxes are paid at the federal or State level.

The not-for-profit model is a standard revenue requirement model and assumes 100% tax exempt debt financing. The model calculates the annual revenue necessary to satisfy the debt obligations as well as the O&M expenses associated with each project and conforms to typical not-for-profit financing principles. The model reflects the annual Cost of Electricity (COE) or revenue requirement per MWh that would be required to own and operate the project. The LCOE is then calculated from the annual revenue requirements.

4.1 Introduction

The LCOE of potential out-of-city renewable resource options is developed based on a review of technical and economic characteristics of commercially available renewable resources that could be deployed throughout California to satisfy CCA program demand. These resources were considered as a means of comparing the LCOE associated with in-city versus out-of-city renewable resource options. The following sections provide a summary of the technical and economic characteristics of these out-of-city renewable supply resources that could satisfy CCA program demand.

4.2 Out-of-City Supply Options

The out-of-city supply options selected for inclusion in this report include the following:

- Solar Photovoltaic (PV) and Solar Thermal or Concentration
- Land-based Wind (Class 3 to 4 and Class 5)
- Renewables Portfolio Standard (RPS) Eligible Hydroelectric
- Geothermal (Flash Steam and Binary Cycle Systems)
- Biomass

4.3 Solar Resources

Solar power technologies use the energy from the sun to generate electricity and include the use of semi-conductor materials such as PV to produce electricity directly from the sun's energy, or systems that capture the heat of the sun to drive a turbine which produces electricity typically referred to as solar concentrating or solar thermal. The various solar power technologies vary in size and design but each is dependent upon the amount and strength of the sun's energy for the production of electricity.

Currently there is 350± MW[11] of solar thermal and 500± MW[12] of solar PV capacity in California and 7± MW[13] in the CCSF. The solar resources considered as out-of-city options include ground-mounted solar PV and solar thermal or solar concentrating technologies.

4.3.1 Geographic Considerations for Solar PV Installations

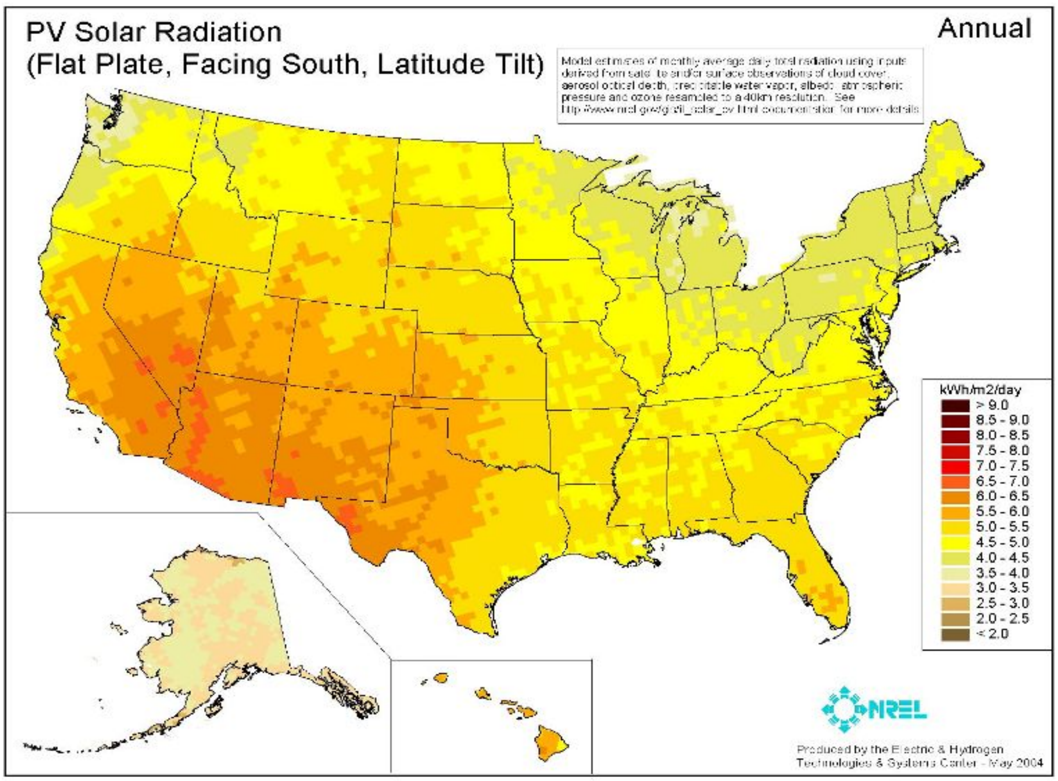
The amount of insolation available at a particular location determines the potential for solar electric generation. Insolation is a measure of solar radiation

[11] Black & Veatch *Renewable Energy Transmission Initiative Phase 1A*, Final Report, April 2008, p. 6-36 at http://www.energy.ca.gov/2008publications/RETI-1000-2008-002/RETI-1000-2008-002-F.PDF.
[12] http://www.cpuc.ca.gov/PUC/energy/Solar/apa09.htm.
[13] SF Solar Facts at http://sf.solarmap.org/.

received on a given surface area in a given time and is commonly expressed as average irradiance in kilowatt-hours per square meter per day (kWh/m^2-day). Insolation values are highest in the summertime and in areas of lower latitudes with drier climates and clear skies.

Figure 4-1 shows that the southwestern states of Nevada, Arizona, and New Mexico tend to have very high insolation values, between 6 and 7.5 kWh/m^2-day. California's Central Valley and southern parts of the State also have insolation values ranging from 5 to 7 kWh/m^2-day,[14] compared with a value of 4 to 5 kWh/m^2-day in the CCSF.

Figure 4-1
PV Solar Radiation in the U.S.



Source: http://www.nrel.gov/gis/solar.html

The locations selected for out-of-city installations were those that were in the central desert area and had a solar insolation value of 6 to 7 kWh/m^2-day which allows for a capacity factor of about 27% for each technology chosen.

[14] CEC *California Solar Resources*, April 2005, CEC-500-2005-072-D, p. 5 at http://www.energy.ca.gov/2005publications/CEC-500-2005-072/CEC-500-2005-072-D.PDF.

4.3.2 Ground-Mounted Installations

Ground-mounted solar PV systems are typically utility-grade and of large scale for use in the production of electricity for delivery to several customers through the utility's transmission/distribution system. An example of a utility-grade PV plant is the Sacramento Municipal Utility District's (SMUD) 3± MW PV installation at Rancho Seco, shown in Figure 4-2.

Figure 4-2 - Ground-Mounted PV System

4.3.3 Solar Thermal Installations

Solar thermal systems require a large footprint and a need for greater than 6 kWh/m2-day[15] which is greater than that typically experienced in the CCSF jurisdiction. Figure 4-3 shows the 5 MW Kimberlina Solar Thermal installation in Bakersfield.

Figure 4-3 - Solar Thermal Installation

4.3.4 Generic Solar Projects

In analyzing the potential LCOE for out-of-city solar resources, a ground-mounted PV system was selected along with a solar thermal project utilizing parabolic trough technology. A discussion of these two systems and the generic characteristics of each are set forth in the following sub-sections. These systems are considered to represent typical projects currently being constructed throughout California. However, projects of varying sizes and technologies could be substituted for the project selected. Assuming the substitute projects have similar technical and economic characteristics and are located in areas with similar natural resources, the LCOE of these alternate projects should be similar to those presented below.

[15] CEC *California Solar Resources*, April 2005, CEC-500-2005-072-D, p. 18 at http://www.energy.ca.gov/2005publications/CEC-500-2005-072/CEC-500-2005-072-D.PDF.

Ground-Mounted Solar PV System

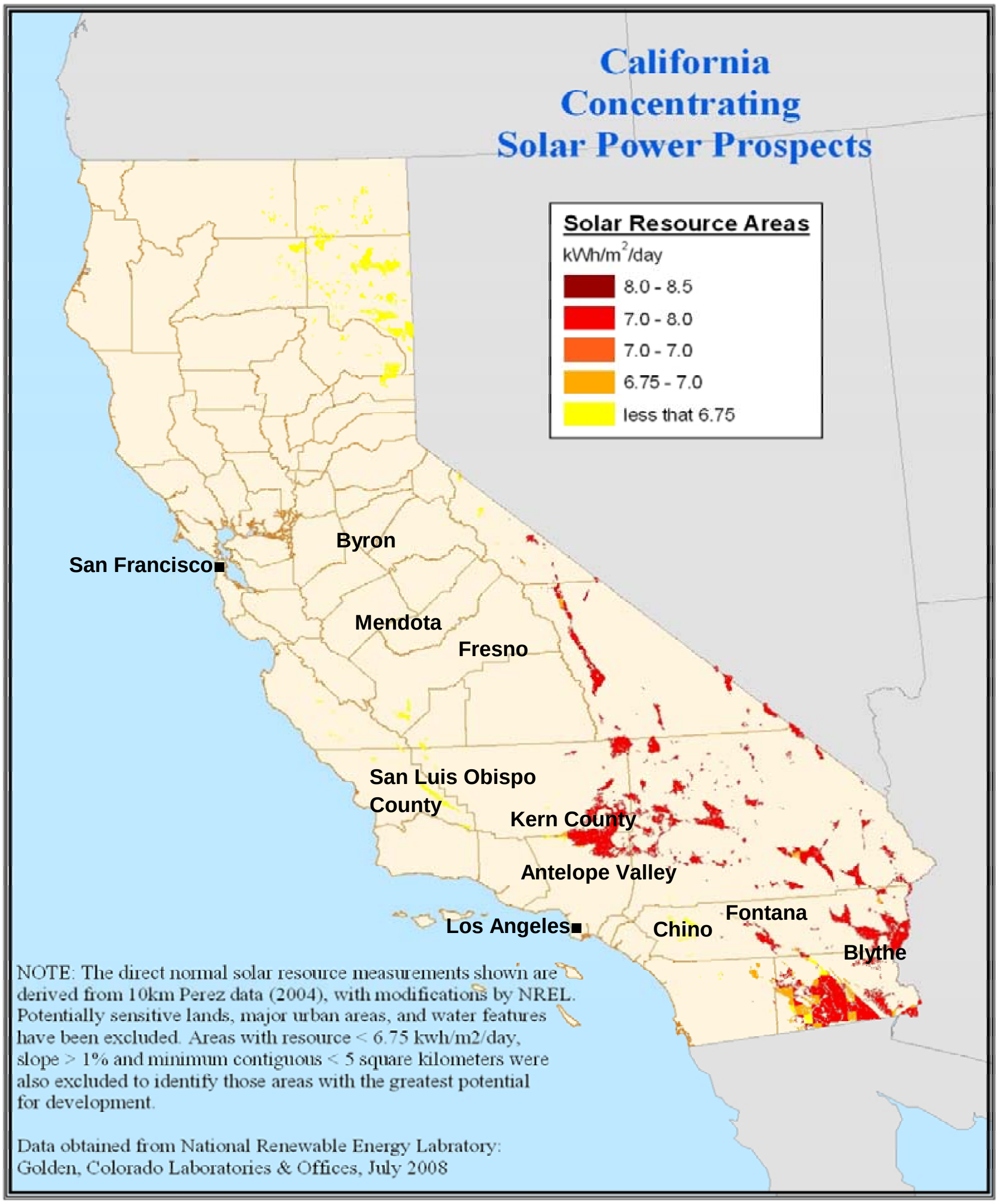
In analyzing the economic potential of solar PV systems for out-of-city deployment, a review of existing and proposed projects was undertaken to assess the potential for this type of installation in the State. According to the California Energy Commission (CEC) website, there are several solar PV projects with California PPAs which are set forth in Table 4-1 and Figure 4-4.

Table 4-1
Solar PV Projects with California PPAs

Utility	Facility Name	Location	Developer Name	Size (MW)	Operational Status	Current Expected Date of First Deliveries
PG&E	Green Volts	Byron	Green Volts Inc.	2	not online	mid-2010
PG&E	CalRenew	Mendota	CalRENEW-1 LLC	5	not online	Apr-10
PG&E	Topaz Solar Farms	Carrizo Plain, San Luis Obispo County	OptiSolar / First Solar	550	not online	Dec-11
PG&E	High Plains Ranch II	Carrizo Plain, San Luis Obispo County	SunPower	210	not online	Dec-10
PG&E	AV solar Ranch	Antelope Valley/ Kern County	Nextlight	230	not online	Dec-13
PG&E	Solaren	Fresno County	Solaren	200	not online	Jun-16
SCE	California Sunrise I	Kern County	Alternative Energy Development LLC	1	not online	redacted
SCE	FSE Blythe 1	Blythe	First Solar	7.5 - 21	not online	Oct-09
SCE	SPV001	Fontana	SCE	2	online	not applicable
SCE	SPV002	Chino	SCE	1	online	not applicable

Source: CEC RPS Contracts Database, updated 7/17/09, at http://www.energy.ca.gov/portfolio/contracts_database.html.

Figure 4-4
General Location of Solar PV Projects with California PPAs



Note: The locations above are general in nature and no guarantee is made for their accuracy.
Source:http://www.energy.ca.gov/maps/solar_potential.html.

In addition, there are over 9,000 MW[16] in the ISO queue[17] and applications for Bureau of Land Management (BLM) rights-of-way in the California deserts

[16] http://www.caiso.com/14e9/14e9ddda1ebf0.pdf
[17] The ISO queue refers to a list of generating projects in the State waiting for electrical interconnection studies.

totaling over 16,000 MW.[18] These figures support the technical potential for PV generation outside of the CCSF that could be used in the CCA program supply mix.

The solar PV system considered for inclusion is 20 MW, located in the southern part of the State. The 20 MW size was selected so that development could utilize the small generation interconnection and still take advantage of the economics of a large project. The project would require approximately 200 acres and be near a 50 to 100 kW substation. In addition, the site was assumed to be relatively flat and have good ingress and egress. The level of solar insolation was between 6 and 7 kWh/m^2-day that resulted in a capacity factor at the high end of the range for California of 27%.

The project includes a single-axis tracking system utilizing multiple crystalline modules. This system is considered to represent the most common PV system proposed for ground-mounted application in the State. A summary of project characteristics is set forth in Table 4-2 below.

Parabolic Trough Solar Thermal System

The most commonly proposed and commercially available solar thermal technology is a parabolic trough system which uses a single-axis tracking system which is comprised of parabolic curved, trough-shaped reflectors to focus the sun's energy onto a receiving pipe which carries the heat transfer fluid. There are currently several parabolic systems operating in California in the Mojave Desert with a combined capacity of 354± MW.[20] These systems are commercially available and are being planned throughout the southwestern part of the U.S.

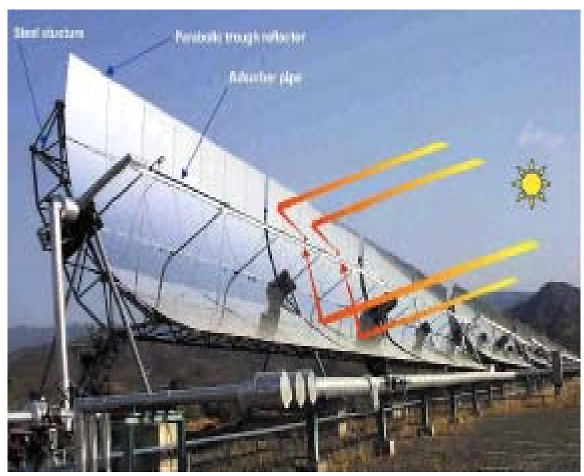


Figure 4-5 Parabolic Trough System

[18] Black & Veatch *Renewable Energy Transmission Initiative Phase 1B*, Final Report, January 2009, Appendix A at http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF
[20] U.S. Department of Energy Concentrating Solar Power Program *Solar Trough Systems* at http://www.nrel.gov/docs/legosti/fy98/22589.pdf.

The project considered for this report is a 200 MW system without thermal storage and utilizes a dry-cooling unit. The site is assumed to be relatively level and has good ingress, egress, and access to transmission infrastructure which minimizes the interconnection costs.

A summary of the project characteristics is provided in Table 4-2.

Table 4-2
Technical and Economic Requirements
for Generic Solar Installations

Description	Ground-Mounted	Parabolic Trough
Project Characteristics		
Plant Capacity (MW)	20	200
Typical Duty Cycle	Intermittent	Intermittent
Unit Life (years)	30	30
Availability Factor	98%	90%
Capacity Factor	27%	27%
MWh/year	47,304	473,040
Construction Period	> 1 year	> 1 year
Technology Status	Mature	Mature
Economic Characteristics (2009$)		
Capital Cost ($/kW)	$6,500.00	$4,000.00
Fixed O&M ($/kW-year)	$65.00	$65.00
Non-Fuel Variable O&M ($/MWh)	$5.00	$5.00
Capital Replacements ($/kW)	$600.00	$250.00
Applicable Incentives	30% ITC 5 yr. MACRS	30% ITC 5 yr. MACRS

4.4 Wind Power Resources

Wind energy systems convert the movement of air to power by means of a rotating turbine and generator. The amount of energy in the wind which is extracted by the wind turbine increases with the cube of the wind speed. Wind strength is typically rated on a scale of Class 1 to Class 7 with Class 1 being poor and Class 7 being excellent. In general, wind strength increases at higher elevations and is why modern turbines have heights of approximately 80 meters, or 260 feet.[21]

Currently there is 2,800± MW of wind capacity in California[22] and 0.5± MW in the CCSF. The out-of-city wind resources available to the CCA program include either a single stand-alone wind project or the ability to purchase a portion of a single facility. The project typically consists of a 50 to 100 MW development which includes multiple

[21] Assuming 10 feet per story, this would equal a 26-story building.
[22] AWEA Project Database (as of 6/27/09) at http://www.awea.org/projects.

turbines supported by steel towers. The average sizes of the units range from 1.5 to 2.5 MW and have heights of 80 meters.

4.4.1 Geographic Considerations for Wind Installations

Wind strength is rated on a scale from Class 1 through 7. Class 4 and higher is generally considered necessary for a site to be economically viable, but some sites with Class 3 wind may be acceptable, depending on cost of construction and available transmission line access. Classes 1 and 2 are generally not economically viable for utility-scale power generation, but may be acceptable for small-scale wind projects. Table 4-3 is a summary of wind classes and associated wind power density.

Table 4-3
Classes of Wind Strength

Wind Power Class	10 m (33 ft)		50 m (164 ft)	
	Wind Power Density (W/m2)	Speed[1] m/s (mph)	Wind Power Density (W/m2)	Speed[1] m/s (mph)
1 (Poor)	0 - 100	4.4 (9.8)	0 - 200	5.6 (12.5)
2	101 - 150	5.1 (11.5)	201 - 300	6.4 (14.3)
3	151 - 200	5.6 (12.5)	301 - 400	7.0 (15.7)
4	201 - 250	6.0 (13.4)	401 - 500	7.5 (16.8)
5	251 - 300	6.4 (14.3)	501 - 600	8.0 (17.9)
6	301 - 400	7.0 (15.7)	601 - 800	8.8 (19.7)
7 (Excellent)	401 - 1,000	9.4 (21.1)	801 - 2,000	11.9 (26.6)

Note: Vertical extrapolation of wind speed based on the 1/7 power law.
[1] Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea-level conditions. To maintain the same power density, speed increases 3%/1000 m (5%/5000 ft) elevation.

Source: http://www.eia.doe.gov/cneaf/solar.renewables/page/wind/wind.html.

Over the last decade, several studies have been undertaken to map wind strength throughout the U.S. and California. This work is typically done with high resolution maps showing wind speed and power density. In California, this work has been undertaken by public entities such as the National Renewable Energy Laboratory (NREL) and CEC, as well as a private company, AWS Truewind.[23] The result of this work is publicly available and typically utilized as a starting point for locating wind power systems. Figure 4-6 shows the annual wind power in the State.

[23] AWS Truewind *Intermittency Analysis Project: Characterizing New Wind Resources in California*, CEC-500-2007-014, February 2007 at http://www.energy.ca.gov/pier/project_reports/CEC-500-2007-081.html.

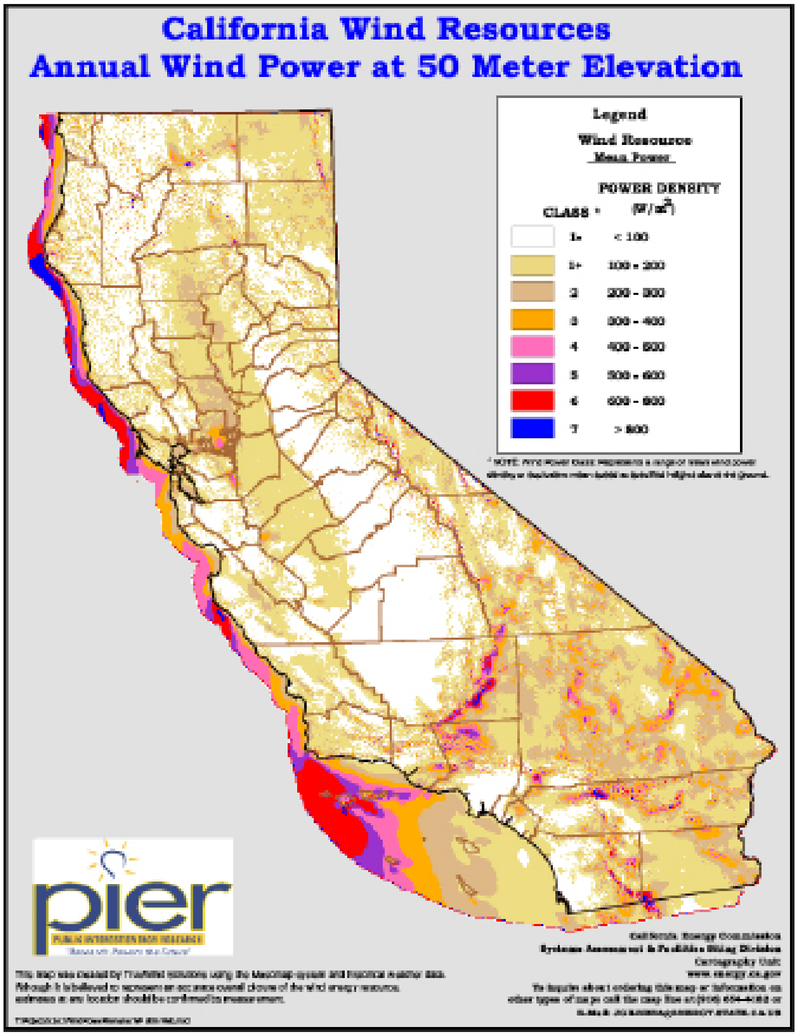


Figure 4-6 – California Wind Resources Annual Wind Power
Source: Edward F. McCarthy and Associates *Wind Resource Assessment for City-Owned Land in San Francisco County and Along the Hetch-Hetchy Right-of-Way*, March 31, 2007 at http://sfwater.org/Files/Reports/WindResourceAssessmentforHetchHetchy.pdf.

The locations selected for the generic projects are those associated with Class 3 to 4 and Class 5 winds. A discussion of these locations in the State is provided below.

4.4.2 Wind Turbine Farms

Utility-scale wind projects consist of multiple turbines with individual turbines ranging in size from 1.5 to 2.5 MW of installed capacity. These installations typically require higher levels of wind and significantly more land. Figure 4-7 shows the 1.8 MW High Winds Energy Center turbines in Solano County, California.

Figure 4-7 - Wind Farm Turbines

4.4.3 Generic Wind Projects

Since 2003, there has been approximately 1,000 MW of wind turbine capacity installed in the State.[24] The sizes of these projects range from less than 1 MW to projects as large as 150 MW of installed capacity utilizing multiple turbines. A summary of these projects is set forth in Table 4-4.

[24] AWEA Project Database (as of 6/27/09) at http://www.awea.org/projects/Projects.aspx?s=California.

Table 4-4
California Utility Wind Plant Installations Since 2003

Name	Location	Capacity (MW)	Units	Turbine Mfr.	Developer	Owner	Power Purchaser	Year Online
Pine Tree Wind Farm	north of Mojave	120.00	80	GE Energy	Los Angeles Department of Water and Power	Los Angeles Department of Water and Power	Los Angeles Department of Water and Power	2009
Shiloh II	Northern California	150.00	75	REPower	enXco	enXco	PG&E	2009
Edom Hills repower	--	20.00	8	Clipper	BP Alternative Energy	BP Alternative Energy	Southern California Edison	2008
Alite Wind Farm	--	24.00	8	Vestas	Allco/Oak Creek Energy	--	California Portland Cement	2008
Dillon	--	45.00	45	Mitsubishi	Iberdrola Renewables	Iberdrola Renewables	Southern California Edison	2008
Solano Wind Project	Solano	63.00	21	Vestas	Sacramento Municipal Utility District	Sacramento Municipal Utility District	Sacramento Municipal Utility District	2007
Buena Vista	Altamont Pass	38.00	38	Mitsubishi	Babcock & Brown	Babcock & Brown	Pacific Gas & Electric	2006
Shiloh Wind Power Project	Solano County	150.00	100	GE Energy	PPM Energy	PPM Energy	PG&E, Modesto Irrigation District & City of Palo Alto Utilities	2006
Solano IIA	Solano County	24.00	8	Vestas	Sacramento Municipal Utility District	Sacramento Municipal Utility District	Sacramento Municipal Utility District	2006
Coram Energy (Aeroman repower)	Tehachapi	10.50	7	GE Energy	Coram Energy	Coram Energy	Southern California Edison	2005
Kumeyaay Wind Power Project	East of San Diego	50.00	25	Gamesa	Superior Renewable Energy	Babcock & Brown	San Diego Gas & Electric	2005
Victorville Wind Project	Victorville Prison	0.75	1	Vestas	NORESCO	NORESCO	Victorville Prison	2005
Victory Garden	Tehachapi	0.66	1	Vestas	Caithness	Caithness	Southern California Edison	2005
Victory Garden	Tehachapi	6.00	8	Zond	Caithness	Caithness	Southern California Edison	2005
Coram Energy (Aeroman repower)	Tehachapi	4.50	3	GE Energy	Coram Energy	Coram Energy	Southern California Edison	2004
Diablo Winds	Altamont Pass	20.46	31	Vestas	FPL Energy	FPL Energy	Pacific Gas & Electric	2004
Lake Palmdale	Palmdale	0.95	1	Vestas	Palmdale Water District	Palmdale Water District	Palmdale Water District	2004
Oasis Power Partners	Tehachapi	60.00	60	Mitsubishi	enXco	enXco	San Diego Gas & Electric	2004
Solano Wind Project, phase II	Solano County	4.62	7	Vestas	FPL Energy	Sacramento Municipal Utility District	Sacramento Municipal Utility District	2004
Aeroman repower (2003)	Tehachapi	3.00	2	GE Energy	Coram Energy	Coram Energy	Southern California Edison	2003
CalWind II CEC	Tehachapi	8.58	13	Vestas	CalWind Resources	--	Southern California Edison	2003
High Winds	Solano	162.00	90	Vestas	FPL Energy	FPL Energy	PPM Energy	2003
Karen Avenue II (San Gorgonio Farms)	San Gorgonio	4.50	3	GE Energy	San Gorgonio Farms	San Gorgonio Farms	Southern California Edison	2003
Mountain View Power Partners III	San Gorgonio	22.44	34	Vestas	PPM Energy	PPM Energy	San Diego Gas & Electric	2003
Solano Wind Project, phase I	Solano County	10.56	16	Vestas	Sacramento Municipal Utility District	Sacramento Municipal Utility District	Sacramento Municipal Utility District	2003
Whitewater Hill	San Gorgonio	4.50	3	GE Energy	Cannon Power Corp.	Cannon Power Corp.		2003
	Total	**1,008.02**						

Source: AWEA Project Database (as of 6/27/2009) at http://www.awea.org/projects/Projects.aspx?s=California

The wind classes from five California locations, determined from Figure 4-8 below, are set forth in Table 4-5, along with the average capacity factor from 1995 to 2005 for each location.

Table 4-5
California Wind Classes and Capacity Factor

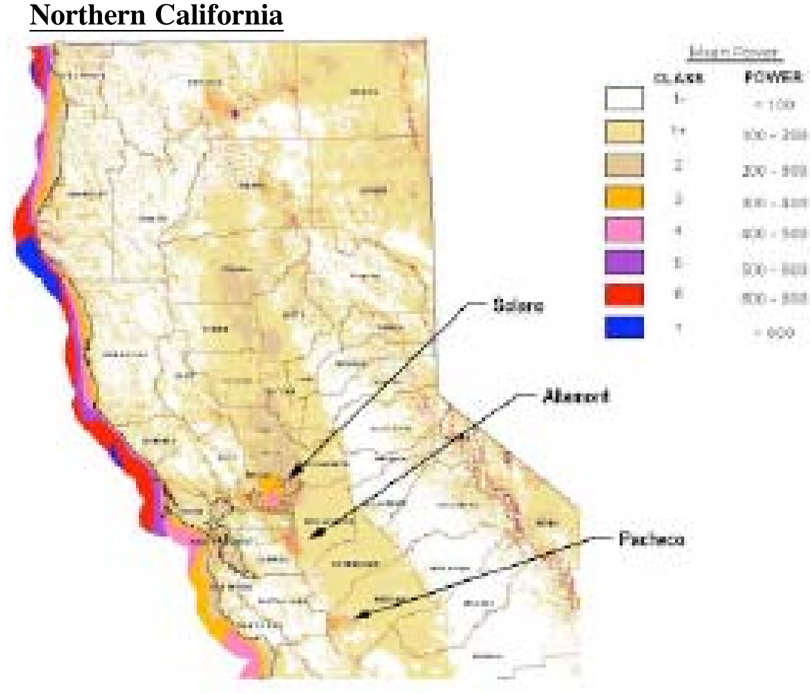
Location	Wind Class	Capacity Factor[1]
Altamont	3-4	18.4%
San Gorgonio	5-7	29.2%
Tehachapi	5-7	26.6%
Pacheco	2-4	16.6%
Solano	3-4	17.7%

[1] Electronic Wind Performance Reporting System (eWPRS) at http://wprs.ucdavis.edu/.

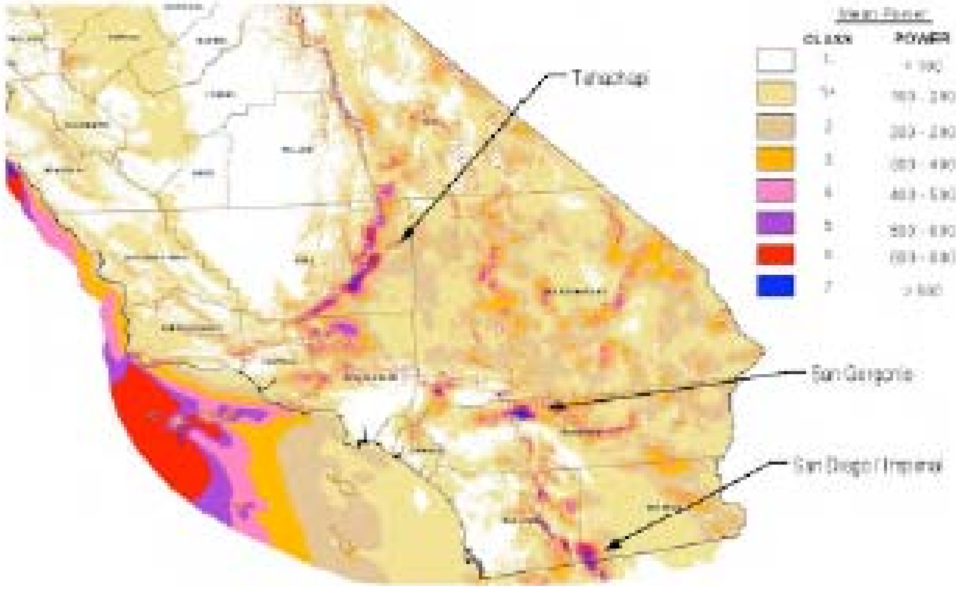
The previously identified locations are shown on the maps of California, set forth in Figure 4-8, to show the relationship to the CCSF.

Figure 4-8
Wind Resource Maps of California

Northern California



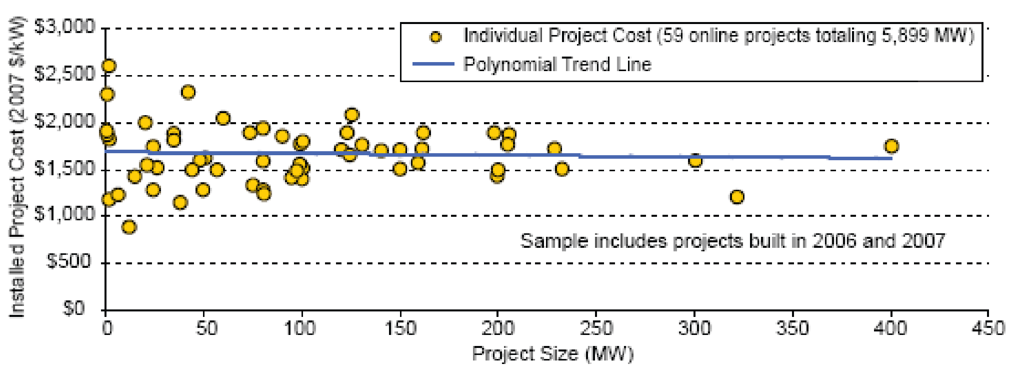
<u>**Southern California**</u>



Source: CEC *Wind Power Generation Trends at Multiple California Sites*, December 2005, p. 10 at http://www.energy.ca.gov/2005publications/CEC-500-2005-185/CEC-500-2005-185.PDF

The wind power system considered in this report includes a 50 MW installation. This size installation is considered reasonable and consistent with current trends. However, additional sizes could produce similar results since wind turbines are modular by nature and do not benefit from significant economies of scale typically associated with large installations. This is demonstrated in Figure 4-9 which illustrates the relationship between project size and cost based on national data for wind turbine installations.

Figure 4-9
Installed Wind Project Costs
as a Function of Project Size – 2006-2007 Projects



Source: U.S. Department of Energy *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*, May 2008, p. 22 at http://www.windpoweringamerica.gov/pdfs/2007_annual_wind_market_report.pdf.

Project Characteristics

The wind power system considered in this report for assessing the technical and economic characteristics of large-scale wind projects consisted of a 50 MW project with an expected life of approximately 30 years. The system has a net output of 50,000 kW or 50 MW and assumes the turbines are installed at a height of 80 meters. The capacity factor is estimated using two classes or strengths of wind. These capacity factors correspond to various wind resources and include Class 3 to 4 wind which results in an average capacity factor of 35% and Class 5 wind which is estimated to have a capacity factor of 40%.

Economic Characteristics

The overnight cost of the installations is estimated at $2,250/kW. This would include the purchase of the units, installation, and a utility interconnection. The operating costs are estimated at $15/kW-yr and include typical maintenance and full-time monitoring of the installation. Inverter replacements are anticipated every 5 to 10 years at a cost of approximately $600/kW plus a $5/MWh variable component.

Table 4-6 provides a summary of the relevant technical and economic characteristics.

Table 4-6
Technical and Economic Requirements
for Generic Wind Turbine Installations

Description	Class 3/4	Class 5
Project Characteristics		
Plant Capacity (MW)	50	50
Typical Duty Cycle	Intermittent	Intermittent
Unit Life (years)	30	30
Availability Factor	98%	98%
Capacity Factor	35%	40%
MWh/year	153,300	175,200
Construction Period	> 1 year	> 1 year
Technology Status	Mature	Mature
Economic Characteristics (2009$)		
Capital Cost ($/kW)	$2,250.00	$2,250.00
Fixed O&M ($/kW-year)	$15.00	$15.00
Non-Fuel Variable O&M ($/MWh)	$5.00	$5.00
Capital Replacements ($/kW)	$600.00	$600.00
Applicable Incentives	30% ITC, PTC 5 yr. MACRS	30% ITC, PTC 5 yr. MACRS

4.5 Hydroelectric Resources

Hydroelectric facilities generate electricity by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing this water through a turbine. The amount of energy captured and electricity produced is a function of the head (vertical height that the water falls) and the flow rate of this water.

There are several types of hydroelectric facility designs and turbines utilized to capture the water's energy. These include:

- Impoundment facilities which utilize a dam to capture water in a reservoir. This water is then released upon demand to generate electricity.
- Run-of-river facilities which use the flow of the river with little or no impoundment, but still utilize some type of dam.
- Diversion facilities which divert a portion of river flows through a penstock, canal, or weir to generate electricity.
- In-line hydroelectric projects which utilize the flow of water through a penstock, aqueduct or pipe to generate electricity based on using the water that has already been diverted to generate electricity.

In California there are nearly 400 hydroelectric plants with a total capacity of about 14,000 MW.[25] The types of installations considered in this report are those that comply with California's RPS and are typically comprised of expansions and upgrades at existing facilities utilizing run-of-river modes of operation.

4.5.1 Hydroelectric Installations

An example of a hydroelectric dam, shown in Figure 4-10, is the SFPUC's Hetch Hetchy Water and Power System which is a complex gravity system including dams, power plants, siphons, pumps, tunnels and pipelines that stretches from the High Sierras to the San Francisco Bay.

Figure 4-10 - Hydroelectric Dam

[25] The amount of hydroelectricity produced varies each year depending on rainfall. Source: http://www.energy.ca.gov/hydroelectric/index.html

4.5.2 Hydroelectric Projects Considered

The hydroelectric projects considered for inclusion in the CCA program supply mix were those that qualify for RPS eligibility[26] under the CEC guidelines.[27] These include the following types of hydroelectric projects which are based on excerpts from the relevant section of the CEC guidelines.

Small Hydroelectric (not conduit)

- The facility was under contract to, or owned by, a retail seller prior to January 1, 2006.
- Generation from a small hydroelectric facility that commences commercial operations or is repowered on or after January 1, 2006 is eligible for the California RPS if the facility meets all of the following criteria:
  1. The facility is 30 MW or less, with an exception for eligible efficiency improvements made after January 1, 2008.
  2. The facility is located in-state or satisfies the out-of-state requirements.
  3. The facility does not "cause an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow."

  Eligible Efficiency Improvements: A small hydroelectric facility shall not lose its RPS eligibility if efficiency improvements undertaken after January 1, 2008 cause it to exceed 30 MW and "the efficiency improvements do not result in an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow."

Conduit Hydroelectric

To be eligible for the RPS, a conduit hydroelectric facility must use for its generation only the hydroelectric potential of an existing pipe, ditch, flume, siphon, tunnel, canal, or other manmade conduit that is operated to distribute water for a beneficial use.[28] A conduit hydroelectric facility may be considered a

[26] The CEC establishes the guidelines associated with the RPS for eligible facilities. A facility is typically eligible if it uses a renewable resource or fuel, satisfies resource-specific criteria, and is either located within the State or satisfies applicable requirements for out-of-state facilities.
[27] CEC *Renewables Portfolio Standard Eligibility, Third Edition, Commission Guidebook,* CEC-300-2007-006-ED3-CMF, January 2008 at http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF.
[28] "Beneficial use" shall be defined consistent with the California Code of Regulations, Title 23, Sections 659 through 672, to include the following uses of water: domestic use, irrigation use, power use,

separate project even though the facility itself is part of a larger hydroelectric facility. The RPS eligibility requirements for conduit hydroelectric facilities depend in part on whether the facility was operational before or after January 1, 2006, and whether eligible energy efficiency improvements were made after January 1, 2008.

- Generation from a conduit hydroelectric facility that commences commercial operations or is repowered on or after January 1, 2006 is eligible for the California RPS if the facility meets all of the following criteria:

  1. The facility is 30 MW or less, with the exception of eligible efficiency improvements made after January 1, 2008.
  2. The facility is located in-state or satisfies the out-of-state requirements.
  3. The facility does not cause an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow.

  Eligible Efficiency Improvements: A conduit hydroelectric facility shall not lose its RPS eligibility if efficiency improvements undertaken after January 1, 2008 cause it to exceed 30 MW and do not result in an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow. The entire generating capacity of the facility shall be RPS-eligible.

  A conduit hydroelectric facility may be associated with or part of a larger existing hydroelectric facility and separately certified as RPS eligible if the facility meets the following criteria:

  1. The existing hydroelectric facility commenced commercial operations before January 1, 2006.
  2. The conduit hydroelectric facility commenced commercial operations on or after January 1, 2006.
  3. The existing hydroelectric facility and conduit hydroelectric facility are separately metered to identify their respective generation.

municipal use, mining use, industrial use, fish and wildlife preservation and enhancement use, aquaculture use, recreational use, and heat control use.

Incremental Hydroelectric Generation from
Efficiency Improvements Regardless of Facility Output

The incremental increase in generation that results from efficiency improvements to a hydroelectric facility, regardless of the electrical output of the facility, is eligible for the RPS if all of the following conditions are met:

1. The facility was operational before January 1, 2007.
2. The efficiency improvements are initiated on or after January 1, 2008, are not the result of routine maintenance activities, and were not included in any resource plan sponsored by the facility owner before January 1, 2008.
3. The facility has, within the immediately preceding 15 years from the date the efficiency improvements are initiated, received certification from the State Water Resources Control Board (SWRCB) pursuant to Section 401 of the Clean Water Act (33 U.S.C. Sec. 1341), or has received certification from a regional board to which the SWRCB has delegated authority to issue certification, unless the facility is exempt from certification because there is no potential discharge into water of the United States.
4. The incremental increase is the result of efficiency improvements from a retrofit, and the efficiency improvements do not result in an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow.
5. All of the incremental increase in electricity generation resulting from the efficiency improvements must be demonstrated to result from a long-term financial commitment by the retail seller.[29]

4.5.3 Generic Hydroelectric Projects

The generic project considered for this report is the result of incremental hydroelectric improvements of an existing facility that has no "adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow.

In-line or in-conduit projects were considered but cost estimates were not developed due to the limited number of market opportunities for these systems. This is due to the existing systems typically being designed to transport water from one location to another based on the energy in the flowing water. The use

[29] "Long-term financial commitment" means either new ownership investment in the facility by the retail seller or a new or renewed contract with a term of more than 10 years, which includes procurement of the incremental generation. [Public Utilities Code Section 399.12.5(b)(4).]

of an in-line hydroelectric device would lower this kinetic energy and typically diminish the ability of the system to accomplish its primary function of water transport.

Project Characteristics

The generic projects could range from $2,000/kW to costs as high as $5,000/kW to expand existing sites, depending on the level of infrastructure necessary to handle the incremental capacity. A figure of $3,500/kW was selected as being a reasonable cost of providing incremental hydroelectric capacity. These sites will have varying capacity factors but an estimated 50% is considered reasonable.

Economic Characteristics

The operating costs are estimated at $15/kW-yr and include typical maintenance and full-time monitoring of the installation plus $5/MWh for variable operating costs.

Table 4-7 provides a summary of the relevant technical and economic characteristics.

Table 4-7
Technical and Economic Requirements
for Generic RPS Eligible Hydroelectric Installation

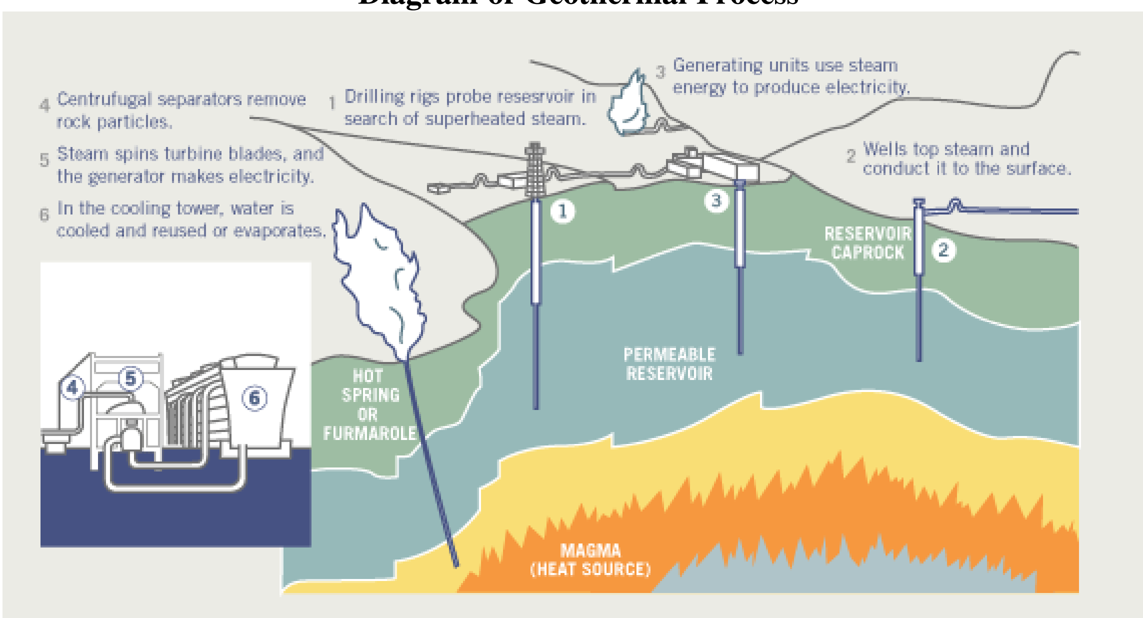
Description	Hydroelectric
Project Characteristics	
Plant Capacity (MW)	10
Typical Duty Cycle	Varies
Unit Life (years)	30
Availability Factor	90%
Capacity Factor	50%
MWh/year	43,800
Construction Period	> 1 year
Technology Status	Mature
Economic Characteristics (2009$)	
Capital Cost ($/kW)	$3,500.00
Fixed O&M ($/kW-year)	$15.00
Non-Fuel Variable O&M ($/MWh)	$5.00
Capital Replacements ($/kW)	$100.00
Applicable Incentives	30% ITC, PTC 5 yr. MACRS

4.6 Geothermal Power Resources

Geothermal power resources can be developed when subsurface temperature gradients are elevated and is most favorable where the earth's crust is relatively thin which leads to a greater flow of heat from the earth's interior. High energy geothermal sites can be used for electricity production and are mostly located in the western parts of the U.S. Geothermal facilities generate power utilizing three types of technology to produce electricity and include flash and dry steam systems and binary cycle systems. In the first two, the geothermal steam is utilized directly to the turbine with water being injected back into the ground from the condensing process. In a binary cycle system, a heat exchanger is used to extract the energy from the earth's geothermal energy and a closed-loop steam system is used in the production of electricity.

There are currently 43± geothermal power plants in California with approximately 1,800 MW of installed capacity. California's geothermal facilities produce about 4.5% of the State's total electricity and two-thirds of the U.S. generation.[30] Figure 4-11 illustrates the geothermal process.

Figure 4-11
Diagram of Geothermal Process



Source: http://www.geysers.com/geothermal.htm

4.6.1 Geographic Considerations for Geothermal Installations

The State's geothermal resources include both dry steam and liquid resources associated with several locations that support geothermal development. Historic

[30] Http://www.energy.ca.gov/geothermal/index.html

development has occurred periodically in The Geysers, the Salton Sea and Coso Hot Springs which are Known Geothermal Resource Areas (KGRA). A map of the various geothermal resources is provided in Figure 4-12.

Figure 4-12
California Known Geothermal Resource Areas (KGRA)

Source: http://www.energy.ca.gov/maps/geothermal_areas.html.

The existing geothermal plants in the State are summarized in Table 4-8, along with the county or location of the project and associated megawatt capacity.

Table 4-8
Location of California Geothermal Power Plants and Capacity

Geothermal Resource Area	County	Existing Gross MW
East Mesa	Imperial	73.2
Heber	Imperial	100.0
Salton Sea (including Westmoreland)	Imperial	350.0
	Imperial Total	523.2
Coso Hot Springs	Inyo	300.0
Geysers (Lake & Sonoma Counties)	Sonoma/Lake	1,000.0
Honey Lake (Wendel-Amedee)	Lassen	6.4
Long Valley (Mono- Long Valley)		
Mammoth Pacific Plants	Mono	40.0
	Total	**1,870**

Source: CEC *California Geothermal Resources* , Staff Paper, April 2005, CEC-500-2005-070, p. 6 at http://www.energy.ca.gov/2005publications/CEC-500-2005-070/CEC-500-

In 2002, GeothermEx, Inc. was retained to perform a geothermal assessment for the State and western Nevada. The study was funded by the SFPUC and utilized prior research, exploration, and development results to assess the selected regions' potential.[31]

The study addressed the amount and quality of available geothermal resources using standard industry techniques and identified approximately 4,732 MW in the 22 resource areas of California. A summary of these results is set forth in Table 4-9 which shows the most likely resource potential within the State.

[31] See CEC *California Geothermal Resources*, Staff Paper, April 2005, CEC-500-2005-070, p. 6 at http://www.energy.ca.gov/2005publications/CEC-500-2005-070/CEC-500-2005-070.PDF.

Table 4-9
Most-Likely (MLK) Geothermal Resource Capacity

Geothermal Resource Area	County	MLK MW	Existing Gross MW	MLK Less Existing Gross MW
Brawley (North)	Imperial	135.0	0.0	135.0
Brawley (East)	Imperial	129.0	0.0	129.0
Brawley (South)	Imperial	62.0	0.0	62.0
Dunes	Imperial	11.0	0.0	11.0
East Mesa	Imperial	148.0	73.2	74.8
Glamis	Imperial	6.4	0.0	6.4
Heber	Imperial	142.0	100.0	42.0
Mount Signal	Imperial	19.0	0.0	19.0
Niland	Imperial	76.0	0.0	76.0
Salton Sea (inclusing Westmoreland)	Imperial	1,750.0	350.0	1,400.0
Superstition Mountain	Imperial	9.5	0.0	9.5
	Imperial Total	2,487.9	523.2	1,964.7
Coso Hot Springs	Inyo	355.0	300.0	55.0
Sulfur Bank Field, Clear Lake Area	Lake	43.0	0.0	43.0
Geysers (Lake & Sonoma Counties)	Sonoma	1,400.0	1,000.0	400.0
Calistoga	Napa	25.0	0.0	25.0
	The Geysers Total	1,468.0	1,000.0	468.0
Honey Lake (Wendel-Amedee)	Lassen	8.3	6.4	1.9
Lake City / Surprise Valley	Modoc	37.0	0.0	37.0
Long Valley (Mono- Long Valley) Mammoth Pacific Plants	Mono	111.0	40.0	71.0
Randsburg	San Bernadino/ Kern	48.0	0.0	48.0
Medicine Lake (Fourmile Hill)	Siskiyou	36.0	0.0	36.0
Medicine Lake (Telephone Flat)	Siskiyou	175.0	0.0	175.0
Sespe Hot Springs	Ventura	5.3	0.0	5.3
	Total	**4,732**	**1,870**	**2,862**

Source: CEC *California Geothermal Resources* , Staff Paper, April 2005, CEC-500-2005-070, p. 8 at http://www.energy.ca.gov/2005publications/CEC-500-2005-070/CEC-500-2005-070.PDF.

This information supports the ability of in-State resources producing additional geothermal electricity.

4.6.2 Geothermal Plants

Figure 4-13 shows one of the plants owned by Calpine at The Geysers in the Mayacamas Mountains located 70± miles north of San Francisco. The Geysers utilizes dry steam and is the largest geothermal development in the world, produces more than 850 MW of electricity, and is considered one of the most reliable energy sources in California.

Figure 4-13 - Geothermal Power Plant

The out-of-city geothermal resources available to the CCA program include representative flash steam and binary cycle system facilities utilized for the technical and economic characteristics of geothermal energy plants.

4.6.2 Generic Geothermal Projects

Flash-Steam Geothermal System

Project Characteristics

The flash-steam system is assumed to be a 20 MW unit with an expected life of 30 years. The system is estimated to have a capacity factor of 90%.

Economic Characteristics

The estimated overnight cost of the installation is $3,500/kW. This would include the purchase of the unit, installation, and a utility interconnection. The operating costs are estimated at $55/kW-yr and include typical maintenance and a full-time operating staff. The variable component is $5/kW.

Binary Cycle Geothermal System

Project Characteristics

The binary cycle system is assumed to be a 20 MW unit with an expected life of 30 years. The system is estimated to have a capacity factor of 90%.

Economic Characteristics

The estimated overnight cost of the installation is $4,000/kW. This would include the purchase of the unit, installation, and a utility interconnection. The operating costs are estimated at $45/kW-yr and include typical maintenance and a full-time operating staff. The variable component is $4.5/kW.

Table 4-10 provides a summary of the technical and economic characteristics of these technologies.

Table 4-10
Technical and Economic Requirements
for Generic Geothermal Installations

Description	Flash-Steam	Binary Cycle
Project Characteristics		
Plant Capacity (MW)	20	20
Typical Duty Cycle	Base Load	Base Load
Unit Life (years)	30	30
Availability Factor	95%	95%
Capacity Factor	90%	90%
MWh/year	157,680	157,680
Construction Period	> 1 year	> 1 year
Technology Status	Mature	Mature
Economic Characteristics (2009$)		
Capital Cost ($/kW)	$3,500.00	$4,000.00
Fixed O&M ($/kW-year)	$55.00	$45.00
Non-Fuel Variable O&M ($/MWh)	$5.00	$4.50
Capital Replacements ($/kW)	$100.0	$100.0
Applicable Incentives	30% ITC, PTC 5 yr. MACRS	30% ITC, PTC 5 yr. MACRS

4.7 Biomass Power Resources

Biomass plants utilize a fuel source with a biological original to produce electricity, wood is the most common source of biomass fuel but other fuels are used such as agricultural waste and dedicated crops. Biomass facilities are typically 50 MW or less and require a large quantity of fuel feedstock in a relatively small geographic region to improve the facility's economics.

The CEC RPS program guidelines refer to biomass technology as those which use a "biomass" fuel. Biomass fuel is defined in the program as follows:[32]

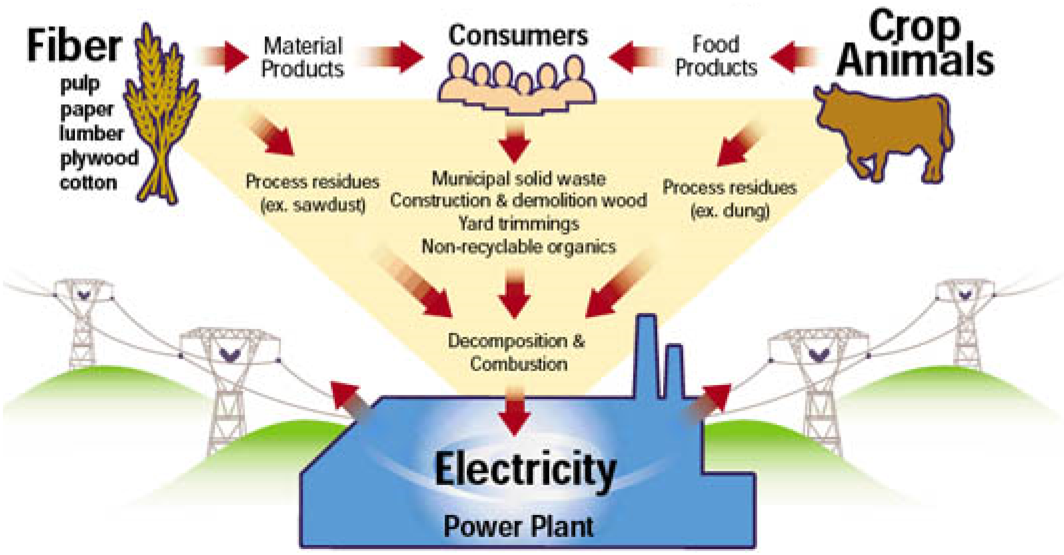
> **Biomass** – any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, sludge derived from organic matter, and wood and wood waste from timbering operations.
>
> Landscape or right-of-way tree trimmings include all solid waste materials that result from tree or vegetation trimming or removal to establish or maintain a right-of-way on public or private land for the following purposes:
>
> 1) For the provision of public utilities, including, but not limited to, natural gas, water, electricity, and telecommunications.
> 2) For fuel hazard reduction resulting in fire protection and prevention.
> 3) For the public's recreational use.

The biomass resources discussed below are intended to utilize these same fuels as identified in the CEC guidelines. This will result in benefits to the environment as fossil fuels are displaced and fuels which are more closely carbon neutral are used in the production of electricity.

Currently there are approximately 30 direct-combustion biomass facilities in operation in California with a capacity of 640 MW.[33] Figure 4-14 illustrates the typical biomass to electricity process.

[32] CEC *Overall Program Guidebook*, March 2007, CEC-300-2007-003-CMF, p. 16 at http://www.energy.ca.gov/2007publications/CEC-300-2007-003/CEC-300-2007-003-CMF.PDF.
[33] http://www.energy.ca.gov/biomass/biomass.html.

Figure 4-14
Diagram of Biomass to Electricity



Source: http://www.energy.ca.gov/biomass/index.html

4.7.1 Biomass Plants

Figure 4-15 shows the 25 MW Rio Bravo Rocklin biomass facility northeast of Roseville. The fuel source is biomass waste mainly consisting of urban wood waste and wood related products. Capacity and energy are sold to PG&E under a 30 year contract.

Figure 4-15 - Biomass Power Plant

In assessing the use of biomass resources, there are two primary methods of extracting electricity from biomass utilizing a combustion process. These include:

- Stoker Boiler Combustion which combusts biomass material on a travelling or vibrating bed. This technology is very mature but typically produces greater emissions than other forms of combustion.
- Fluidized Bed Combustion wherein the biomass fuel is suspended in a mix of silica and limestone through the application of air. These types of boilers typically produce lower emissions.

In selecting a technology for consideration in this report, fluidized bed combustion was selected as being the project most likely to be constructed in the State.

4.7.2 Generic Biomass Project

Project Characteristics

A fluidized bed boiler rated at 50 MW was considered in this report for assessing the technical and economic characteristics of biomass resources with an expected life of 30 years. The capacity factor is estimated at 85% and is assumed to have sufficient fuel.

Economic Characteristics

The overnight estimated cost of the installation is $3,500/kW. This would include the purchase of the unit, installation, and a utility interconnection. The operating costs are estimated at $100/kW-yr for fixed O&M and $4.50/MWh for variable expenses.

In addition to fixed and variable expenses, biomass facilities utilize wood or another biomass-based fuel source. Currently this fuel is priced at approximately $3.00/mmBtu delivered to the plant with actual cost per fuel source varying depending on moisture content and Btus available in the feedstock. These costs are estimated to increase at the rate of inflation.

Table 4-11 provides a summary of the technical and economic characteristics of these technologies.

Table 4-11
Technical and Economic Requirements
for Generic Biomass Installations

Description	Fluidized Bed Combustion
Project Characteristics	
Plant Capacity (MW)	50
Typical Duty Cycle	Base Load
Unit Life (years)	30
Availability Factor	95%
Capacity Factor	85%
MWh/year	372,300
Construction Period	> 1 year
Technology Status	Mature
Economic Characteristics (2009$)	
Capital Cost ($/kW)	$3,500.00
Fixed O&M ($/kW-year)	$100.00
Non-Fuel Variable O&M ($/MWh)	$4.50
Capital Replacements ($/kW)	$100.00
Applicable Incentives	30% ITC 5 yr. MACRS

5.1 Introduction

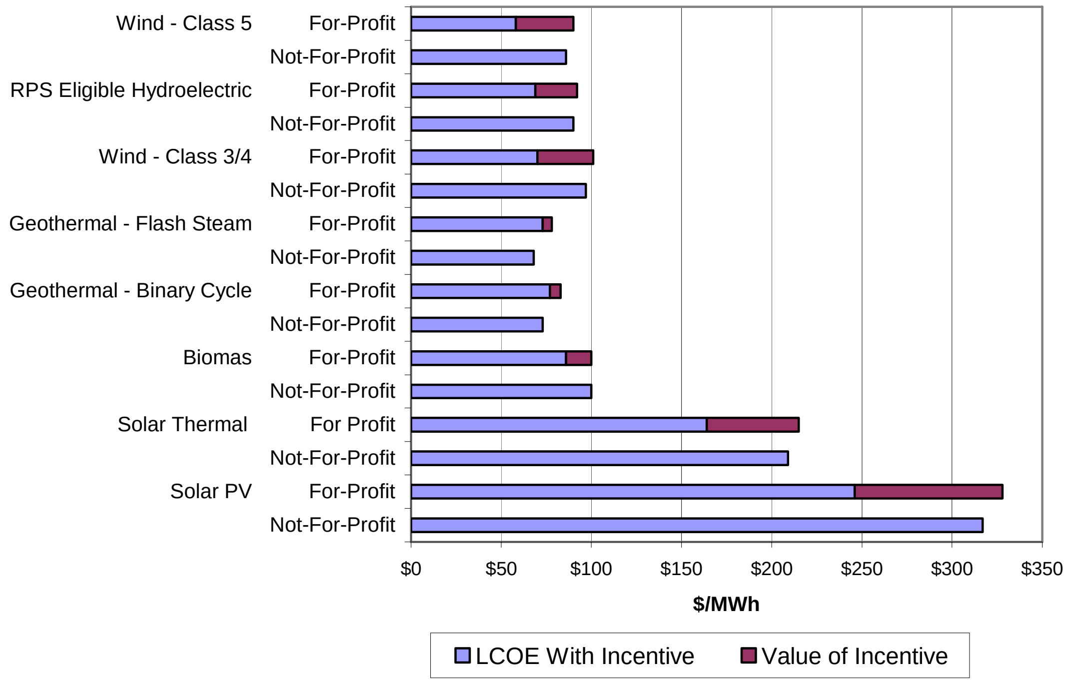
The LCOE of the theoretically and technically possible renewable energy resources identified in Section 4 was developed using the spreadsheet models developed by GES. A separate model was developed for each ownership structure that addresses the capital structure and ability of each ownership type to take advantage of incentives available to renewable resources. The model calculates the LCOE of each resource technology based on resource-specific cost and operating data and market-based assumptions about financing, federal and State tax liability or benefits, and other incentives available to each technology. The for-profit model minimizes the LCOE over a 20-year period while maintaining debt financing requirements and equity returns necessary to satisfy investor requirements. The not-for-profit model develops the LCOE by calculating the revenue requirements associated with each project assuming 100% debt financing and no federal or State income tax benefits or liability over a 20-year period.

The results of each analysis are set forth in Table 5-1 and Figure 5-1. A discussion of these results and specific assumptions is provided below for each resource category.

Table 5-1
Summary of Levelized Cost of Electricity (LCOE)
($/MWh)

	For-Profit	Not-For-Profit @ 5% Interest Rate
Solar PV	$246	$317
Solar Thermal	$164	$209
Wind - Class 3/4	$70	$97
Wind - Class 5	$58	$86
RPS Eligible Hydroelectric	$69	$90
Geothermal - Flash Steam	$73	$68
Geothermal - Binary Cycle	$77	$73
Biomass	$86	$100

Figure 5-1
Levelized Cost of Electricity (LCOE)
(in ascending order by For-Profit)



5.2 Installed Costs

The installed costs of the projects are based on the overnight costs presented in Section 4 plus an indirect cost adder for additional owner's costs associated with each project. A summary of the overnight and installed costs is presented below for each of the technologies discussed in Section 4.

Table 5-2
Calculation of Installed Costs

A	B	C	D	E
			Installed Cost ($/kW)	
Technology	Net Capacity (MW)	Overnight Cost ($/kW)	For-Profit (1.07 multiplier)	Not-For-Profit (1.05 multiplier)
			[C × 1.07]	[C × 1.05]
Solar				
Ground-Mounted Solar PV	20.0	$6,500	$6,955	$6,825
Solar Thermal	200.0	$4,000	$4,280	$4,200
Wind Power				
Class 3/4	50.0	$2,250	$2,408	$2,363
Class 5	50.0	$2,250	$2,408	$2,363
Hydroelectric				
Expansion of Existing Facility	10.0	$3,500	$3,745	$3,675
Geothermal				
Flash Steam	20.0	$3,500	$3,745	$3,675
Binary Cycle	20.0	$4,000	$4,280	$4,200
Biomass				
Fluidized Bed Combustion	50.0	$3,500	$3,745	$3,675

5.3 Operating Costs for Selected Resources

The O&M costs for each technology are estimated based on both the fixed and variable operating costs of the technology. The annual fixed expense is expressed in 2009$ per kilowatt-year ($/kW-yr) and the variable expense is expressed in 2009$ per megawatt-hour ($/MWh).

The fixed or variable expenses for each technology are set forth in Table 5-3 and are based on information set forth in the Task 1 report. These costs are considered sufficient to operate the project and assume that it operates at its maximum efficiency.

In addition to the direct O&M costs, certain technologies require either annual capital replacements or a lump sum replacement in a particular period. These are set forth in this table as well, either on a $/kW-yr basis or as a lump sum at Year 10 for inverter replacements associated with solar PV and wind installations. If the figures are set forth in a lump sum, a formula is used on the pro forma to annualize this expense so that costs are spread over the useful life of the capital replacements.

Table 5-3
Calculation of Fixed and Variable Expenses

Technology	Net Capacity (MW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Replacement ($/kW-yr)
Solar				
Ground-Mounted Solar PV	20.0	$65.00	$5.00	$600.00
Solar Thermal	200.0	$65.00	$5.00	$250.00
Wind Power				
Class 3/4	50.0	$15.00	$5.00	$600.00
Class 5	50.0	$15.00	$5.00	$600.00
Hydroelectric				
Expansion of Existing Facility	10.0	$15.00	$5.00	$100.00
Geothermal				
Flash Steam	20.0	$55.00	$5.00	$100.00
Binary Cycle	20.0	$45.00	$4.50	$100.00
Biomass				
Fluidized Bed Combustion	50.0	$100.00	$4.50	$100.00

5.4 Solar LCOE Ranges from $164 to $317/MWh

The for- and not-for-profit LCOE for various solar installations considered technically feasible in the CCSF were calculated for each type of ownership and ranged from a low of $164/MWh to a high of $317/MWh. The results of the LCOE models are set forth in Table 5-4.

Table 5-4
Solar Resources
($/MWh)

	For-Profit		Nor-For-Profit (5% Interest Rate)	
	First Year	LCOE	First Year	LCOE
Solar PV	$199	$246	$278	$317
Solar Thermal	$133	$164	$184	$209

The LCOE indicates that in each instance, the use of a for-profit ownership structure and sales of electricity to the CCA program using a PPA results in the lowest LCOE due to the high level of federal and State incentives available to for-profit owners of solar installations. The solar thermal installation had the lower LCOE. The not-for-profit LCOE calculations are higher in all instances due to the inability of the owner to utilize federal incentives provided through the U.S. Tax Code.

5.5 Wind LCOE Ranges from $58 to $97/MWh

The for- and not-for-profit LCOE for the various wind installations ranged from a low of $58/MWh to a high of $97/MWh. The results of the LDOC models are set forth in Table 5-5.

Table 5-5
Wind Resources
($/MWh)

	For-Profit		Nor-For-Profit (5% Interest Rate)	
	First Year	**LCOE**	**First Year**	**LCOE**
Wind - Class 3/4	$57	$70	$83	$97
Wind - Class 5	$47	$58	$73	$86

As with solar, the PPA approach to procuring renewable resources results in the lowest LCOE due to the high level of incentives tied to the U.S. Tax Code. The most attractive project would be a Class 5 project.

5.6 RPS Eligible Hydroelectric LCOE Ranges from $69 to $90/MWh

The LCOE for an RPS eligible hydroelectric facility is estimated at $69 and $90/MWh for the for- and not-for-profit ownership structures, respectively. These are among the lowest LCOEs developed and demonstrate the attractiveness of hydroelecltric resources.

5.7 Geothermal LCOE Ranges from $73 to $77/MWh

The for- and not-for-profit LCOE for the various geothermal installations ranged from a low of $73/MWh to a high of $77/MWh. The results of the LDOC models are set forth in Table 5-6.

Table 5-6
Geothermal Resources
($/MWh)

	For-Profit		Nor-For-Profit (5% Interest Rate)	
	First Year	**LCOE**	**First Year**	**LCOE**
Geothermal - Flash Steam	$59	$73	$56	$68
Geothermal - Binary Cycle	$62	$77	$61	$73

5.8 Biomass LCOE Ranges from $86 to $100/MWh

The LCOE for a biomass facility is estimated at $86 and $100/MWh for the for- and not-for-profit ownership structures, respectively.