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RENEWABLE ENERGY COST OF GENERATION UPDATE

PIER INTERIM PROJECT REPORT

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Public Interest Energy Research Program

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Renewable Energy Cost of Generation Update is the interim report for the Renewable Energy Cost of Generation Update project (Contract Number 500-06-014, work authorization number KEMA-06-020-P-R) conducted by KEMA, Inc. The information from this project contributes to PIER's Renewable Energy Technologies Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

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Abstract

This 2009 report updates the cost of generating electricity for technologies if built in California. California Energy Commission staff provides factors that affect costs, including cost assumptions, for 15 renewable technologies, coal-integrated gasification, combined-cycle, and nuclear power generation alternatives for utility-scale generation technologies. These costs are useful in evaluating the financial feasibility of a generation technology and for comparing the costs of building and operating one particular energy technology with another. These estimates update the 2007 cost of generation, based on empirical data collected from operating facilities, research from primary sources, actual costs and surveys of expected costs from experts in the field, and reference documents. This report details a range of instant and installed costs with projected costs based on two years of significant growth in renewable technologies, changes in material costs, and inflation.

Keywords: Renewable energy, cost of generation, biomass, geothermal, hydropower, solar, parabolic trough, photovoltaic, PV, thermal solar, wind energy, ocean wave, integrated gasification combined-cycle, IGCC, nuclear

Executive Summary

This study examines the costs of renewable electricity generation in California to support the cost of generation modeling work of the Electricity Analysis Office. In addition to renewable electricity cost of generation assessment, nuclear and integrated gasification combined-cycle generation are also examined. The California Energy Commission is tasked with developing robust cost of generation estimates, backed by solid research leveraging the full assessment of previous research on the cost of generation, cost drivers and trends, and expected cost trajectories for future costs. All of these data are then used by the Energy Commission to estimate the levelized cost of generation by technology.[1]

In the last several years, California has experienced tremendous activity in the renewable energy market, largely driven by several key pieces of legislation. The following table outlines some recent legislation that has been adopted that is likely to have a significant impact on the cost of generation for renewables as well as conventional generation.

Table 1. Recent California Legislation That May Affect Cost of Generation

Bill	Author	Year Passed	Summary
SB1	Murray (Chapter 132)	2006	SB 1 establishes in statute the California Solar Initiative with a goal of 3,000 megawatts of new solar produced electricity by the end of 2016. The California Solar Initiative Program has a $3.35 billion budget that will be administered by the California Public Utilities Commission, Energy Commission, and publicly owned utilities.
SB 107	Simitian (Chapter 464)	2006	SB 107 accelerates California's Renewables Portfolio Standard targets by requiring California's retail sellers of electricity to increase renewable energy purchases by at least 1 percent per year with a target of 20 percent renewable energy by 2010. It also requires the publicly owned utilities to file reports with the Energy Commission that outline their specific Renewables Portfolio Standard goals and progress towards the goals.
SB 1250	Perata (Chapter 512)	2006	SB 1250, combined with SB 107, continues the authorization of the Energy Commission's ongoing use of public goods charge funds for the period of 2007-2012 for the continued operation of the Energy Commission's Renewable Energy Program.
AB 2189	Blakeslee (Chapter 747)	2006	AB 2189 modifies the Renewables Portfolio Standard eligibility requirements for small hydroelectric generation facilities regarding efficiency improvements that result in increased capacity.

[1] Levelized cost is the constant annual cost that is equivalent on a present-value basis to the actual annual costs, which are themselves variable.

Bill	Author	Year Passed	Summary
AB 32	Núñez	2006	Global Warming Solutions Act – sets mandatory targets for greenhouse gas emission reductions. Commits to reducing greenhouse gas emissions to 2000 levels by 2010 (11 percent below business as usual), to 1990 levels by 2020 (25 percent below business as usual), and 80 percent below 1990 levels by 2050. Requires the California Air Resources Board and the Energy Commission to determine baselines and create systems to track greenhouse gas emissions.

Source: California Energy Commission

The ambitious goals – a Renewables Portfolio Standard of 20 percent by 2010 and 33 percent by 2020, 3,000 megawatts (MW) of photovoltaics installed within a decade, and an 11 percent reduction in greenhouse gas emissions by 2010 – are ambitious but achievable.

The Energy Commission's work in the previous integrated energy policy reports confirm that the technical potential for renewables in California and the Western Electricity Coordinating Council region dwarfs these goals. In addition, developers of renewable energy power plants and the solar photovoltaic industry have responded to increased demand for renewable energy with enthusiasm. The Energy Commission intends to bridge the established policy backdrop and the surging renewable market to convert technical potential into reality.

KEMA, Inc. (KEMA) performed a detailed assessment of the generation technologies that might be available in the next 20 years. For each technology, KEMA assessed cost drivers and trends to develop input variables for the Energy Commission's levelized cost model. To provide this information, researchers performed the following:

- Literature review and identification of renewable energy and two non-renewable energy technologies likely to be deployed in California over the next 20 years, along with identification of the scale at which they are likely to be deployed.
- Cost drivers and trend analysis for each likely contributing technology and analysis of factors that determine the range (high, average, and low) of expected costs.
- Cost model input for utility-scale technologies, including current nominal costs and plausible minimum and maximum costs for each utility-scale technology, broken down into input variables that are used in the Energy Commission's levelized cost analysis.
- Expected paths for future costs for utility-scale generation technologies, plus a discussion of factors that determine these costs, as the basis for calculating levelized energy costs.

The four topics listed above are addressed for utility-scale technologies in the interim project report. The final project report will also address community and building-scale technologies as well as summarize key findings and recommendations.

1.0 Introduction

Renewable energy deployment in California is expected to accelerate in the near term in response to legislation identifying supply portfolio targets and climate mitigation targets. Related policy development must be based on the best possible economic information, especially the cost of bulk renewable energy electricity generation. In addition, two non-renewable energy technologies are examined in support of the cost of generation modeling work of the Electricity Analysis Office and as comparisons to the renewable energy technologies. The two non-renewable energy technologies included in this report are nuclear and integrated gasification combined-cycle (IGCC). To provide this information, four fundamental topics were addressed:

- Literature review and identification of renewable energy and two non-renewable energy technologies likely to be deployed in California over the next 20 years, along with identification of the infrastructure scales at which they are likely to be deployed.
- Cost drivers and trend analysis for each likely contributing technology and quantitative analysis of factors that determine the range of expected costs.
- Cost model input for utility-scale technologies, including current nominal costs and plausible minimum and maximum costs for each utility-scale technology, broken down into categories that are used in California Energy Commission (Energy Commission) levelized cost analysis.
- Expected paths for future costs for utility-scale generation technologies, plus quantitative discussion of factors that determine these costs, as the basis for calculating levelized energy costs.

The four topics listed above are addressed for utility-scale technologies in the interim project report. The final project report will also address community and building-scale technologies and the following two topics:

- Reconciliation of currently quoted forward energy prices and currently estimated levelized costs, discussing the relative impact of various factors other than overnight construction cost that determine pricing. Reconciliation here refers to explaining the differences between prices and costs, identifying the factors that account for the differences, and providing estimates of the sizes of these factors.
- Costs and cost trajectories for community and building-scale renewable energy technologies, along with minimum and maximum costs and trajectories for these scales.

The project was undertaken to achieve the following objectives:

- Critically review, adjust and augment the content of Appendix B of Energy Commission Report #CEC-200-2007-011-SF, December 2007 (Comparative Costs of California Central

Station Electricity Generation Technologies, Klein and Rednam) in order to create comparable information for the *2009 Integrated Energy Policy Report (IEPR)*.

- Update renewable energy and non-renewable energy inputs for use in the Energy Commission's Cost of Generation Model, used in preparing the *2009 IEPR*.
- Reconcile price and cost information for representative utility-scale power purchases.
- Estimate costs and trajectories for community and building-scale technologies.

The following section describes the project approach followed by a section on project outcomes. The Project Outcomes section of the report includes an introduction to the technologies that were selected with the sections following organized by technology.

2.0 Project Approach

This section discusses the tasks the research team undertook and what the team did to accomplish the project objectives.

2.1. Task 1: Technologies

The research team undertook the following activities:

- Conducted a technical and analytical critique of reference documents, including:
    - Comparative Costs of California Central Station Electricity Generation Technologies[2] published by the California Energy Commission in December 2007.
    - Costs and supply curves generated in support of California Public Utilities Commission (CPUC) Greenhouse Gas (GHG) Modeling Project. Final results and GHG Calculator v2b from E3.[3]
    - Costs estimates found and used in the RETI Phase 1A and 1B reports by Black & Veatch in Renewable Energy Transmission Initiative Phase 1A.[4]
- Recommended utility-scale RE technologies for cost analysis with technical and market justification. Utility-scale RE technologies are generally defined as those over 20 MW.
- Identified the primary existing commercial embodiment of each utility-scale technology in California. The term commercial embodiment is intended to describe the most prevalent commercially available application of a technology. As an example, in the case of solar thermal power, the primary existing application is concentrating parabolic trough collectors, augmented by natural gas-fired boilers and supplying heat to steam Rankine power plants in the 50 MW to 80 MW size range.
- Identified the expected primary commercial embodiment in 2018.

The research team will revisit Task 1 for the community and building-scale technologies in the second phase of the project and include findings in the final project report.

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2 Klein, Joel and Anitha Rednam. *Comparative Costs of California Central Station Electricity Generation Technologies*. California Energy Commission, Electricity Supply Analysis Division, CEC-200-2007-011, December 2007. http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

3 GHG Calculator v2b, updated on 5/13/08. http://www.ethree.com/CPUC_GHG_Model.html.

4 Black & Veatch. *Renewable Energy Transmission Initiative Phase 1A* (Draft Report). Black & Veatch, RETI Stakeholder Steering Committee, Project Number 149148.0010, March 2008. http://www.energy.ca.gov/2008publications/RETI-1000-2008-001/RETI-1000-2008-001-D.PDF.

Please also note that this study provides estimates for cost of generation technologies but does not provide levelized life-cycle cost estimates for the various energy technologies.[5]

2.2. Task 2: Cost Drivers

For each of the utility-scale technologies identified in Task 1, the research team identified:

- Market and industry changes since August 2007 that have materially affected costs.
- Current trends that will materially affect future costs.
- Primary general and California-specific cost drivers (e.g., plant scale, global industry manufacturing scale, resource quality, plant location, capacity factor in case of storage coupled plants, overnight cost).

2.3. Task 3: Current Costs

For each of the utility-scale technologies identified in Task 1, the research team identified:

- Nominal 2009 costs in the format required for the Energy Commission's levelized Cost of Generation model.
- Plausible minimum, average, and maximum costs with technical justification. To the extent possible, plausible maximum is defined as a cost more than one competitive player would be willing to pay, and plausible minimum is defined as is the least cost recorded absent hidden subsidies. In some cases, unique site characteristics were also considered.

The process for compiling data–of the plausible minimum, average, and maximum cost cases–was discussed between the research team and Energy Commission staff. Establishing ranges between minimum, average, and maximum costs circumscribes the range of market costs that would reasonably be encountered in the actual development, construction, and operation within each technology.

For each technology, size ranges were identified for total plant capacity to determine minimum, average, and maximum plant capacities in megawatts (MW). Plant capacity factors and forced outage rates were also defined using minimum, average, and maximum values, reflecting the ranges identified through researched values. North American Energy Reliability Corporation (NERC)/Generating Availability Data System (GADS) fleet reliability data were used for technologies where data was available, and in the case of wind, solar, and biomass technologies, other research sources were identified. Plant heat rates and fuel usage data were similarly modeled for low/average/high cases, based on actual operating plant characteristics; data was compiled for each fossil technology fuel usage reflecting in-service values for generating plants.

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5 Levelized life-cycle cost estimates include the total cost of a project from construction to retirement and decommissioning. The research team's cost estimates for nuclear energy do not include nuclear plant decommissioning and waste disposal costs.

Fuel cost estimates were derived with ranges for each fuel type based on published studies and data from coal, natural gas, uranium, and biomass.

Overnight and installed capital cost values for minimum, average, and maximum costs were defined through two approaches. For overnight costs, capital cost ranges were developed through documented plant cost histories and adjusted for capacity scaling effects, noting that the overnight cost per kilowatt depends on the total capacity of the plant. Further adjustments to overnight cost were made to reflect the cost driver analysis, showing learning effects of cumulative generation. These experience curve effects were reflected on the year-to-year overnight costs within the generation technology dataset.

For installed capital cost values, the low/average/high cases were developed primarily through the use of differing construction time durations where such data could be verified by the research team. This data reflects the uncertainty in concept-to-completion time for each technology and results in cost impact due to additional interest costs and allowance for funds used during construction charges (AFUDC).

The use and application of renewable energy and other tax incentives were also considered and modeled with the input dataset to develop low/average/high cost data values. These tax incentives were applied for each technology, based on their current validity and specific application for each technology.

The dataset contains cells for low/average/high values for each input to the cost of generation model, and each specific input is modeled with its own low/average/high cost range. One may not draw the conclusion that these costs are specific to a particular size project – for example, the low plant capacity automatically generates the highest operating cost. Instead, the datasets were compiled so that each technology dimension (e.g., capacity, forced outage rate, heat rate, overnight cost) has its own low/average/high range and is not associated with a relative capacity or size project. In that way, the data is modeled such that the range of inputs defining low/average/high costs reflect boundaries for each technology; and the minimum cost represents the lowest plausible range of cost, and the maximum cost represents the highest plausible range of cost for each technology.

2.4. Task 4: Expected Cost Trajectories

The research team developed a spreadsheet model using cost driver information to estimate future cost trajectories (costs expected in each year from 2009-2029) of the recommended utility-scale technologies identified in Task 1.

The spreadsheet model to develop expected cost trajectories for each technology was developed using the concept of learning effects and the experience curve. Experience curves are used in developing technology policy because they show the market effects of increased cumulative production. As the market adopts a new energy technology, manufacturers gain economies of scale due to increased production, and they learn how to improve the technology. Both of these factors over time can lower unit costs of production.

The primary definition of experience curve effects is captured in what is termed the progress ratio for a technology. Simply put, the progress ratio is the expected percentage decrease in unit cost, based on a doubling of cumulative output of that technology. As an example, a technology that has a progress ratio of 0.90 would indicate that a doubling of installed units for that technology choice would result in a 10% unit cost reduction.[6]

Energy technologies generally have technology progress ratios in the range from 0.70 to 1.00, with the lower number indicating a rapid learning rate and lowering of unit costs over time (new technology deployment) and progress ratios close to unity reflecting extremely mature technologies with only small, incremental learning effects.

The research team noted that it is possible for technologies to exhibit changes in progress ratios over time, due to several factors:

- Disruptive Technology Advances – breakthrough developments in a technology that significantly affect unit cost and/or pace of learning for a manufacturer.
- Price Subsidies – Artificial price subsidies can alter the balance between experience and learning, and mitigate learning effects, since the price signal is not a true competitive market signal.
- Changes in Macroeconomic Fundamentals – They can affect supply/demand balance and adoption rates of technologies, enhancing or inhibiting learning effects of additional production.

These changes over time demonstrate that one value for progress ratio and experience effects is generally not suitable for modeling the experience curve over time, especially for those technologies with high learning effects. The research team thus modeled a range of learning effects, with documented progress ratios for each technology modified through the use of key cost drivers that were identified for each technology choice.

In the modeling of these learning effects, the technology progress ratio and experience effects, which typically range from 0.70 to 1.00, were modified through the use of cost driver rates of change ratios. These cost driver ratios begin at unity (1.00) as a base case, which reflects the normal, expected experience curve, and the ratios can be weighted as greater than unity, which imply a lesser learning effect, or less than unity, which imply a greater, accelerated learning effect than the normal experience curve.

Cost drivers were subjectively evaluated based on two factors: importance weighting (how important the driver is to the technology cost improvement) and low/high ranges to reflect the subjective variation in learning effect. For each technology and the researched technology

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6 International Energy Agency. *Experience Curves for Energy Technology Policy*. Organization of Economic Cooperation and Development (OECD), 2000.

progress ratio, each cost driver was modeled at unity for the average case and then modified for the low/high cases based on the research team technical findings and judgment.

A modified progress ratio, calculated as the product of the expected technology experience curve (shown as Technology Progress Ratio in the example below) and the weighted average cost driver effect, combines the effects of the baseline technology experience curve and identified cost drivers that might either accelerate or decelerate the cost improvements associated with an increase in the cumulative installed base for each technology. This modified progress ratio is used for final cost modeling for each technology.

The weighted average cases for low/average/high cost driver effects using the modified progress ratio were then modeled using the standard experience curve equation and year-over-year price changes identified. These price changes were used to develop the forecasted overnight costs for each technology.

2.4.1. Method

The experience curve effects and cost drivers were developed for each technology by combining the expected variability in identified cost drivers with the published data reflecting the expected learning curve effects for each renewable energy technology, as published by the U.S. Department of Energy (DOE) and other industry sources. The research team modified the experience curve effects by the weighted impact each cost driver could have on the technology and its cost trajectory.

A model was developed to calculate these impacts and is shown below in Table 2:

Table 2. Cost Driver Analysis Worksheet Example

Cost Driver Analysis

	Technology:	**Onshore Wind**	7		
	Technology Progress Ratio:	**0.900**			
			Rate of Change		
	Cost Driver	**Percentage**	**Low**	**Average**	**High**
1	Turbine Costs	75.0%	0.95	1.00	1.10
2	Reliability	10.0%	0.97	1.00	1.04
3	Permitting/Site Selection	5.0%	0.98	1.00	1.02
4	Land Acquisition	5.0%	0.99	1.00	1.01
5	Transmission Costs	5.0%	0.97	1.00	1.10
	Total and Averages:	**100.0%**	**0.96**	**1.00**	**1.09**
	Modified Progress Ratio:		0.86	0.90	0.98

Source: KEMA

For example, the above sheet shows the calculations made for the onshore wind renewable technology. The technology progress ratio for onshore wind is identified as 0.90 as a baseline from industry published data.[7] This baseline value for experience curve effects is then subjectively adjusted by each cost driver ratio, and then a weighted average is taken that takes the subjective effects of these cost drivers into account.

The calculated weighted average is then shown as the modified progress ratio, or the expected range in learning curve effects with additional cumulative capacity over time. In the case above, the expected range in modified progress ratio is from a low value of 0.86 to a high value of 0.98, which implies that with a doubling of overall installed capacity, the expected decrease in costs would be between 2% and 14%, with an average expected decrease of 10%.

The next step in computing experience curve effects and overall cost trajectories is developing reliable estimates for cumulative installed capacity for each technology. This was done through two primary research sources: the Energy Information Administration's (EIA) Annual Energy Outlook for 2009[8] and European Wind Energy Association's (EWEA) Pure Power report, [9] which provides global data for offshore wind technology adoption. Cumulative installed capacity forecasts were compiled for each technology using this reference source data.

The overall cost trajectory developed in a year-over year fashion was computed using the standard experience curve formula:

$$Cost\_Ratio \equiv \left[\frac{Cumulative\_Generation_{Y}}{Cumulative\_Generation_{Y-1}} \right] \wedge \ln\left(\frac{Modified\_\Pr ogress\_Ratio}{2} \right)$$

This cost ratio was developed in the cost driver data worksheets for each technology and then used to adjust the forecasted yearly costs for each technology.

2.5. Task 5: Price/Cost Reconciliation

In a later phase of the project, the research team will:

- Analyze publicly available pricing information for representative utility-scale RE power purchases in California.
- Reconcile representative prices and estimated levelized life cycle costs, including the relative impact of factors other than cost that determine pricing, e.g., state and federal incentives and tax policies, financing assumptions, and the cost of credit.

The project outcomes from the research team's analysis for Task 5 will be presented in the final project report.

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7 U.S. DOE. Energy Information Administration. *Learning Curve Effects for New Technologies*.

8 U.S. Department of Energy. Energy Information Administration. Annual Energy Outlook 2009 (AEO2009). DOE/EIA-0383(2009), March 2009.

9 Zervos, Arthourous, Christian Kjaer,. *Pure Power: Wind Energy Scenarios up to 2030*. European Wind Energy Association, March 2008.

2.6. Task 6: Community and Building Scale Renewable Energy Costs

In a later phase of the project, the research team will:

- Identify sources of relevant U.S. cost information for renewable energy heating and cooling technologies.
- Estimate nominal costs and expected cost trajectories for recommended community- and building-scale RE technologies.
- Present plausible minimum and maximum costs and cost trajectories for same, with explanation of factors that vary and cause costs to vary.

The project outcomes from the research team's analysis for Task 6 will be presented in the final project report.

3.0 Project Outcomes

This section presents the research results. The technologies selected in Task 1 are presented in Section 3.1 along with a description of the method for selecting the technologies. Note that the community and building-scale technologies will be included in the final project report. The sections following 3.1 are organized by technology and include outcomes from Tasks 2, 3, and 4.

3.1. Technologies

The research team conducted a technical and analytical critique of reference documents in order to recommend technologies for cost analysis. The interim project report includes the research team's recommendations for utility-scale technologies (i.e., > 20 MW). The final project report will include recommended community-scale RE technologies (i.e., 1 – 20 MW) and building-scale RE technologies (i.e., < 1 MW).

3.1.1. Technical and Analytical Critique of Reference Documents

To set the foundation for the research efforts, KEMA performed a technical and analytical critique of the following key reference documents:

- *Comparative Costs of California Central Station Electricity Generation Technologies*[10] published by the California Energy Commission in December 2007.
- Costs and supply curves generated in support of California Public Utilities Commission (CPUC) Greenhouse Gas (GHG) Modeling Project. Final results and GHG Calculator v2b from E3.[11]
- Costs estimates found and used in the RETI Phase 1A and 1B reports by Black & Veatch in *Renewable Energy Transmission Initiative Phase 1A*.[12]

All of these studies have published assumptions about the cost of generation for renewable technologies, nuclear, and IGCC. KEMA's review of the studies indicates that four broad categories of benefits and costs are assessed, including:

- Generation costs

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10 Klein, Joel and Anitha Rednam. *Comparative Costs of California Central Station Electricity Generation Technologies*. California Energy Commission, Electricity Supply Analysis Division, CEC-200-2007-011, December 2007. http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

11 GHG Calculator v2b, updated 5/13/08. http://www.ethree.com/CPUC_GHG_Model.html.

12 Black & Veatch. *Renewable Energy Transmission Initiative Phase 1A* (Draft Report). Black & Veatch, RETI Stakeholder Steering Committee, Project Number 149148.0010, March 2008. http://www.energy.ca.gov/2008publications/RETI-1000-2008-001/RETI-1000-2008-001-D.PDF.

- Transmission costs
- Integration costs
- Environmental benefits and other externalities

Generation costs are always considered since they generally form the basis of cost estimation. Treatment of transmission costs, integration costs, and environmental benefits is not consistent and treatment of externalities is even less common.

The three studies are briefly described below followed by comparison tables of key input assumptions.

2007 Cost of Generation Report

The Energy Commission's Cost of Generation Report (COG) provides levelized cost estimates for various central station generation technologies in California. The levelized cost estimates were developed using the Energy Commission's Cost of Generation Model which was initially developed to support the *2003 Integrated Energy Policy Report* (*IEPR*). The 2007 Cost of Generation Report used a newly refined Cost of Generation Model to estimate the levelized costs of energy for three classes of developers: investor owned utilities, publicly owned utilities, and merchant plants. The report summarizes the levelized cost estimates in a clear and concise manner for eight conventional technologies and twenty renewable technologies for the three classes of developers. It also documents key input assumptions and compares the 2007 input assumptions to those used in the *2003 IEPR* forecast and EIA estimates. A general description of the Energy Commission's Model and method is provided as well as user instructions and explanation of the screening and sensitivity analysis components of the Model.

CPUC 2008 GHG Modeling Project

The cost and supply curves generated by the California Public Utilities Commission (CPUC) GHG Modeling Project in 2008 provide a benchmark for which to compare the key assumptions and levelized cost estimates provided in this study. The analysis used a GHG calculator developed by E3 and reviewed through the stakeholder process under the CPUC GHG docket R. 06-04-009.

The CPUC is scheduled to complete the first phase of the implementation analysis in early 2009. The intent is to conduct a renewable penetration barrier analysis and to develop plausible resource portfolios for California Independent System Operator (California ISO) to analyze further.[13] In addition, the analysis will estimate net cost and rate impacts, looking at cost and rate impacts of the 33% Renewables Portfolio Standard (RPS) portfolio relative to a 20% RPS reference case baseline. Though the results of the CPUC 2009 analysis are not yet available, KEMA assessed the study based on publicly available presentations.[14] According to a CPUC

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13 The study does not recommend optimal renewable resource portfolios.

14 CPUC, Aspen, E3, and Plexos. "33% Implementation Analysis Working Group Meeting." CPUC, 2008.

presentation, RETI provided useful inputs for the 2008 CPUC GHG Modeling Project and the pending CPUC 33% Implementation Analysis.

The E3 calculator considers factors such as integration costs and renewable impact on wholesale prices. The study performed a sensitivity analysis that determined four key drivers of results in the electricity sector:

- Load growth assumptions.
- Fuel prices.
- EE achievements.
- Carbon dioxide (CO_2) market costs.

Inclusion of CO_2 market costs has become increasingly important for planning purposes in California. According to E3, CO_2 costs are treated as an exogenous input to the model. The analyst using the GHG calculator inputs a CO_2 price, as well as any assumptions about offset prices, and whether CO_2 permits are auctioned or allocated, among other CO_2 market design questions. CO_2 costs are then calculated and allocated to load-serving entities differently based on the selected scenario. CO_2 costs are tracked only for retail providers and CO_2 costs to existing generators are not tracked.

RETI 1A 2008 and IB 2009 Studies

According to the RETI Report, RETI's goal is to "identify transmission facilities likely to be required to meet a 33% RPS requirement by the year 2020." The RETI IB 2009 study developed information for ranking potential renewable resources grouped by geographic proximity, development timeframe, shared transmission constraints, and economic benefits. It also estimated the value of energy by considering time of day and capacity value of resource (contribution to system reliability). It then conducted a high-level screening analysis ranking the renewable zones by cost effectiveness, environmental concerns, development and schedule uncertainty, and other factors. The renewables resources ranking by grouping is intended to assist in transmission planning.

The RETI analysis has not yet included integrated costs in its method. However, it appears that there is a plan to include these costs may be included in future RETI analyses should the information be developed in an appropriate manner that it warrants inclusion in the cost estimates. For instance, further information on integration costs are needed to support estimates on the cost to integrate intermittent wind and solar resources.

Transmission costs calculated by Black & Veatch and used in the Phase 1 economic ranking assume simultaneous delivery of the full nameplate generating capacity of every competitive renewable energy zone (CREZ). This conservative approach is appropriate for a high-level screening analysis yet without doubt overstates the amount and cost of the transmission facilities necessary to meet current state GHG and renewable energy goals.

The method employed by the RETI team includes scenario analysis to analyze the effects of different policy scenarios, resource portfolios and technology options and costs. This method allowed the RETI analysis to assess the impacts of uncertainty on the ranking process. The RETI analysis also appears to include carbon costs based on a GHG adder.

Comparison of 2009 Analysis With the 2007 IEPR Data

The following table provides a comparison of the key assumptions presented in the *2007 IEPR* and KEMA's 2009 analysis.

Table 3. Comparison between 2009 KEMA analysis and 2007 IEPR

Technology	Gross Capacity (MW)		Capacity Factor (%)		Instant Cost ($/KW)		Fixed O&M ($/kW-Yr)		Variable O&M ($/MWh)	
	2009 KEMA	2007 IEPR	2009 KEMA	2007 IEPR	2009 KEMA	2007 IEPR	2009 KEMA	2007 IEPR	2009 KEMA	2007 IEPR
Biomass Combustion - Fluidized Bed Boiler	28	25	85%	85%	$3,200	$3,156	$99.50	$150.26	$4.47	$3.11
Biomass Combustion - Stoker Boiler	38	25	85%	85%	$2,600	$2,899	$160.00	$134.72	$6.98	$3.11
Biomass Cofiring	20	N/A	90%	N/A	$500	N/A	$15.00	N/A	$1.27	N/A
Biomass - IGCC	30	21.25	75%	85%	$2,950	$3,121	$150.00	155.44	$4.00	3.11
Geothermal - Binary	15	50	90%	95%	$4,046	$3,093	$47.44	$72.54	$4.55	$4.66
Geothermal - Flash	30	50	94%	93%	$3,676	$2,866	$58.38	$82.90	$5.06	$4.58
Hydro – Small Scale or "Developed Sites"	15	10	30%	52%	$1,730	$4,125	$17.57	$13.47	$3.48	$3.11
Hydro – Capacity Upgrade	80	N/A	30%	N/A	$771	N/A	$12.59	N/A	$2.39	N/A
Solar - Parabolic Trough	250	63.5	27%	27%	$3,687	$4,021	$68.00	$62.18	$0.00	$0.00
Solar - Parabolic Trough with Storage	250	N/A	65%	N/A	$5,406	N/A	$68.00	N/A	$10.30	N/A
Solar - Photovoltaic (Single Axis)	25	1	27%	22%	$4,550	$9,611	$68.00	$24.87	$0.00	$0.00
Onshore Wind - Class 5	100	N/A	42%	N/A	$1,990	N/A	$13.70	N/A	$5.50	N/A
Onshore Wind – Class 3/4	50	50	37%	34%	$1,990	$1,959	$13.70	$31.09	$5.50	$0.00
Offshore Wind - Class 5 (2018 start date)	100	N/A	45%	N/A	$5,588	N/A	$27.40	N/A	$11.00	N/A
Ocean Wave (2018 start date)	40	0.75	26%	15%	$2,587	$7,203	$36.00	$31.09	$12.00	$25.91
Coal - IGCC	300	575	80%	60%	$2,250	$2,198	$41.70	$36.27	$6.67	$3.11
Nuclear: Westinghouse-AP1000	960	1000	86%	85%	$4,000	$2,950	$147.70	$140.00	$5.27	$5.00

Source: KEMA and 2007 Integrated Energy Policy Report

Notes to Table: If N/A is listed, no data was available. The hydro "developed sites" category is analogous to the hydro small-scale category used in the *2007 IEPR*. Gross capacity refers to the gross electrical generation output, Capacity factor refers to the full-load equivalent operational percentage for a unit, and instant cost refers to the cost to build a unit immediately (without construction interest or escalation effects). The instant cost for nuclear energy does not include decommissioning or nuclear waste disposal costs.

Key observations include:

- The hydroelectric for developed sites without power discrepancy in instant costs is primarily due to estimated licensing and mitigation costs. KEMA examined the Idaho National Laboratory (INL) database of potential sites and found that the average mitigation costs were substantially less than what was estimated in 2007.
- The capacity factor for the hydro was determined through an analysis of existing hydroelectric plants in California. Through this analysis, the average capacity factor was found to be much lower than the *2007 IEPR* estimate.
- Solar photovoltaic (PV) single-axis instant costs have decreased substantially since the *2007 IEPR*. These decreasing cost trends are consistent with several research and financial sources as well as significant economies of scale associated with the change from a 1 megawatt (MW) unit to a 25 MW installation. Section 3.5.3 provides further documentation of KEMA's assumptions and source documents.
- Ocean wave is a new technology resource category at the central scale project level that is scheduled to become a viable resource in the 2018 timeframe. The instant costs are not directly comparable between a 40 MW system and the 0.75 MW pilot project that was included in the *2007 IEPR* analysis.
- The *2007 IEPR* analysis did not cover Class 5 wind specifically. Rather, they included one broad wind category that aligns closely with Class 3 and 4. The data aligns quite nicely between the two studies. Costs per unit of capacity and energy are expected to decline as machine size and output per unit increases.

Offshore wind is a new category in the 2009 analysis and is scheduled to come on-line in the 2018 timeframe. Offshore wind instant costs are estimated to be approximately twice that of onshore wind.

The coal IGCC capacity factor is substantially higher in the KEMA 2009 analysis. This change is based on actual plant data and warranted because as technologies mature capacity factors tend to increase.

The instant cost of nuclear is higher in the 2009 analysis versus the *2007 IEPR* estimate. The KEMA data is based on the Westinghouse–AP 1000 system, and, as discussed in Section 3.8 of this report, the nuclear data is well substantiated by several research and financial sources. In addition, the information is consistent with data available from major operators such as Florida Power and Light, Georgia Power, and South Carolina Electric and Gas Company.

The *2009 IEPR* cost of generation report will add to the previous analyses of renewable resources in the following manner:

- The cost estimates will be presented as a range (high, mid, low) of estimates to reflect the uncertainty and other factors that affect project costs.
- Installed costs have been added that include the carrying cost of capital during the average construction periods.
- Include explicitly cost trajectories affected by specific influences into the future.
- Clearly including financing and other construction-related costs beyond engineering estimates.
- Providing explicit reference documentation for renewable technologies.
- Assessing of costs for community or building scale technologies.

Comparison of 2009 Analysis With the CPUC GHG Modeling Project

KEMA's 2009 analysis is compared to the data that was presented in the CPUC GHG modeling project in the following table.

Table 4. Comparison of 2009 analysis with the CPUC GHG model data

Technology	Gross Capacity (MW)*		Capacity Factor (%)		Instant Cost ($/KW)		Fixed O&M ($/kW-Yr)		Variable O&M ($/MWh)	
	2009 KEMA	CPUC E3 Data 2008$	2009 KEMA	CPUC E3 Data 2008$	2009 KEMA	CPUC E3 Data 2008$	2009 KEMA	CPUC E3 Data 2008$	2009 KEMA	CPUC E3 Data 2008$
Biomass[1]		1		85%		$3,737		$107.50		$0.01
Biomass Combustion - Fluidized Bed Boiler	28		85%		$3,200		$ 99.50		$ 4.47	
Biomass Combustion - Stoker Boiler	38		85%		$2,600		$160.00		$ 6.98	
Biomass Cofiring	20		90%		$500		$ 15.00		$ 1.27	
Biomass - IGCC	30		75%		$2,950		$150.00		$ 4.00	
Geothermal[2]		1		90%		$3,011		$154.92		$ -
Geothermal - Binary	15		90%		$4,046		$47.44		$ 4.55	
Geothermal - Flash	30		94%		$3,676		$58.38		$ 5.06	
Hydro - Small Scale or "Developed Sites"	15	1	30%	50%	$1,730	$2,402	$17.57	$13.40	$ 3.48	$3.30
Hydro – Capacity Upgrade	80	N/A	30%	N/A	$771	N/A	$12.59	N/A	$2.39	N/A
Solar - Parabolic Trough	250	1	27%	40%	$3,687	$2,696	$68.00	$49.63	$ -	$ -
Solar - Parabolic Trough with Storage	250	N/A	65%	N/A	$5,406	N/A	$68.00	N/A	$10.30	N/A

Technology	Gross Capacity (MW)*		Capacity Factor (%)		Instant Cost ($/KW)		Fixed O&M ($/kW-Yr)		Variable O&M ($/MWh)	
Solar - Photovoltaic (Single Axis)	25		27%		$4,550		$68.00		$ -	
Wind[3]		1		37%		$1,931		$ 28.51		
Onshore Wind - Class 5	100		42%		$1,990		$13.70		$ 5.50	
Onshore Wind - Class 3/4	50		37%		$1,990		$13.70		$ 5.50	
Offshore Wind - Class 5 (2018 start date)	100	N/A	45%	N/A	$5,588	N/A	$27.40	N/A	$11.00	N/A
Ocean Wave (2018 start date)	40	N/A	26%	N/A	$2,587	N/A	$36.00	N/A	$12.00	N/A
Coal - IGCC	300	1	80%	85%	$2,250	$2,388	$41.70	$ 36.36	$ 6.67	$2.75
Nuclear: Westinghouse - AP1000	960	1	86%	85%	$4,000	$3,333	$147.70	$ 63.88	$ 5.27	$0.47

Notes: Source for CPUC E3 data is GHG Calculator v2b (May 2008).[15]
1) Biomass is listed as generic category in the CPUC GHG Model
2) Geothermal is listed as generic category in the CPUC GHG Model
3) Wind is listed as a generic category (no Class is listed)
* Capacity MW was listed as 1 MW in all cases

Source: KEMA and CPUC

Key observations include:

- Cost characterizations and heat rates in the GHG model come primarily from the EIA 2007 Annual Energy Outlook Report.[16]
- Direct comparison of data is difficult due to lack of data on unit size assumptions.
- The CPUC data does not include solar single-axis PV systems, despite recent announcements in California for larger scale centralized PV system applications.
- The CPUC solar thermal instant cost estimates are substantially lower than the *2007 IEPR*, a 2006 National Renewable Energy Laboratory (NREL) study and KEMA's 2009 estimate for reasons that are not easy to identify. KEMA's cost data is based on a 2006 NREL/Black & Veatch study and independent research on capital costs of projects in Spain and the United States. Cost estimates and discussion of major market drivers are included in Section 3.5.2.

15 http://www.ethree.com/CPUC_GHG_Model.html. *E3 GHG Calculator v2b*, May 2008.

16 U.S. DOE. Energy Information Administration. *Assumptions to the Annual Energy Outlook*. 2007.

- KEMA's Class 3 and 4 wind data aligns closely with the CPUC data. E3 benchmarked wind costs to a recent American Wind Energy Association (AWEA) study.
- All costs in the GHG model were inflated by 25% per year for two years to reflect the recent rapid inflation in construction costs. Given the recent downturn in the economy, this assumption may no longer be appropriate.
- The CPUC GHG model includes site-specific transmission interconnection distances for geothermal, solar thermal, wind and hydro. Conversely, KEMA's 2009 assessment includes transmission costs and voltage conversion from the generation plant to the local first point of interconnection to the transmission or distribution network.
- The CPUC data includes wind and small hydro include *firming resource* costs based on cost of CTs needed to reach 90% availability on peak. KEMA's assessment does not include *firming resource* costs.

Comparison of 2009 Analysis With the RETI Project (Phase 1A and 1B)

The 2009 analysis is compared to the data that was presented in RETI 1A report in the following table.

Table 5. Comparison between 2009 Analysis with the RETI 1A Data

Technology	Gross Capacity (MW)		Capacity Factor (%)		Instant Cost ($/KW)		Fixed O&M ($/kW-Yr)		Variable O&M ($/MWh)	
	2009	RETI 1A	2009	RETI 1A	2009	RETI 1A	2009	RETI 1A	2009	RETI 1A
Solid Biomass[1]		35		80%		$4,000		$83		$11.00
Biomass Combustion - Fluidized Bed Boiler*	28		85%		$3,200		$99.50		$4.47	
Biomass Combustion - Stoker Boiler*	38		85%		$2,600		$160.00		$6.98	
Biomass Cofiring	20	35	90%	85%	$500	$400	$15.00	$10	$1.27	$0.00
Biomass - IGCC	30	N/A	75%	N/A	$2,950	N/A	$150.00	N/A	$4.00	N/A
Geothermal[2]		30		80%		$4,000		$0		$27.50
Geothermal – Binary	15		90%		$4,046		$47.44		$4.55	
Geothermal - Flash	30		94%		$3,676		$58.38		$5.06	
Hydro - "Developed Sites" or "New" as listed in RETI	15	<50	30%	50%	$1,730	$3,250	$17.57	$15	$3.48	$6.00
Hydro – Capacity Upgrade or "Incremental" in RETI	80	300	30%	50%	$771	$1800	$12.59	$15	$2.39	$4.75
Solar - Parabolic Trough	250	200	27%	28%	$3,687	$3,900	$68.00	$66	$0.00	$0.00

Technology	Gross Capacity (MW)		Capacity Factor (%)		Instant Cost ($/KW)		Fixed O&M ($/kW-Yr)		Variable O&M ($/MWh)	
Solar - Parabolic Trough with Storage	250	N/A	65%	N/A	$5,406	N/A	$68.00	N/A	$10.30	N/A
Solar - Photovoltaic (Single Axis)	25	20	27%	28%	$4,550	$7,000	$68.00	$35	$0.00	$0.00
Wind[3]		100		32%		$2,150		$50		$0.00
Onshore Wind - Class 5**	100		42%		$1,990		$13.70		$5.50	
Onshore Wind - Class 3/4	50		37%		$1,990		$13.70		$5.50	
Offshore Wind - Class 5	100	200	45%	40%	$5,588	$5,500	$27.40	$88.00	$11.00	$0
Ocean Wave	40	100	26%	35%	$2,587	$4,000	$36.00	$210	$12.00	$11.00
Coal – IGCC	300	N/A	80%	N/A	$2,250	N/A	$41.70	N/A	$6.67	N/A
Nuclear: Westinghouse - AP1000	960	N/A	86%	N/A	$4,000	N/A	$147.70	N/A	$5.27	N/A

Notes:
1) RETI 1A Solid Biomass.
2) Only one category of geothermal is listed in the RETI 1A Report.
3) Only one category of onshore wind is listed in the RETI 1A Report.
If ranges were presented in RETI 1A data, midpoints are listed in the table

Source: KEMA, Black & Veatch RETI 1A Report, 2008

Key observations include the following:

- For the most part, the KEMA analysis is fairly consistent with the RETI data.
- Information on underlying assumptions in RETI report on the two hydro categories is limited. Therefore, it is difficult to assess why cost estimates vary between KEMA 2009 data and the RETI IA data.
- The RETI IA instant cost data for solar parabolic trough appears to align nicely with KEMA's data.
- The instant cost for solar PV single-axis systems is significantly lower in the KEMA study than the RETI analysis. The KEMA data is strongly supported by recent declining price trends as discussed in Section 3.5.3.

Summary

More and more studies that assess cost of achieving RPS goals are taking macroeconomic and externality benefits into account. For instance, some studies are now assessing macroeconomic benefits of renewable generation including benefits associated with growth in the clean technology industry and employment. Externalities should also potentially be examined either on a qualitative or quantitative basis. For instance, the benefit associated with renewables in helping to serve as a hedge against the price of fossil fuel could potentially be quantified.

Future studies should consider including:

- CO_2 abatement costs.
- Qualitative or quantitative assessment of other key issues that may influence costs of generation including:
  - Environmental sensitivity.
  - Land-use constraints.
  - Permitting risk.
  - Transmission constraints and equity issues related to who bears the cost of new transmission.
  - System integration costs.
  - System diversity.
  - Tax credit availability and structure.
  - Financing availability.
  - Macro-economic benefits (jobs creation, security, fuel diversity, etc.).
  - Natural gas price and wholesale price effects associated with increased penetration of renewables.
  - Other risk factors.

3.1.2. Method for Selecting Technologies

The research team used the following screening criteria to select the majority of technologies for cost analysis:

- Is the technology commercially available and in use on any level other than a demonstration phase?
- Are there a number of projects in use in the United States or abroad that use this technology?
- Is this a viable technology for use in California or in neighboring states? If so, what is the production potential?
- Are there any regulatory issues or other restrictions for use in California?

- Is there any actual cost data available for the existing installations that can be used in the study?

Cost analysis for the technologies that passed these screening technologies was conducted to provide data starting in 2009 (i.e., current start data). In several cases, technologies that are not currently commercially available were selected for cost analysis. These technologies were included because there is substantial demonstration project activity or sufficient interest in these technologies to expect that these technologies could be commercially available and dominant in 10 years time. Since no cost data from commercial installations is readily available for these technologies, the authors expect greater uncertainty around the costs. The authors have identified these technologies in the table below with a data start date of 2018. The utility-scale technologies falling into this category are Biomass Co-Gasification IGCC, Offshore Wind (Class 5), and Ocean Wave.

3.1.3. Utility-Scale Technologies

The utility-scale technologies recommended for cost analysis are shown in Table 6 below.

Table 6. Central plant technology list for COG modeling project

Technology List	Gross Capacity (MW)	Data Start Date
Biomass		
Biomass Combustion - Fluidized Bed Boiler	28	Current
Biomass Combustion - Stoker Boiler	38	Current
Biomass Cofiring	20	Current
Biomass Co-Gasification IGCC	30	2018
Geothermal		
Geothermal - Binary	15	Current
Geothermal - Flash	30	Current
Hydropower		
Hydro - Small Scale (developed sites without power)	15	Current
Hydro - Capacity upgrade for developed sites with power	80	Current
Solar		
Solar - Parabolic Trough	250	Current
Solar - Photovoltaic (Single Axis)	25	Current
Wind		
Onshore Wind - Class 5	100	Current
Onshore Wind - Class 3/4	50	Current
Offshore Wind - Class 5	100	2018
Wave		
Ocean Wave	40	2018
Integrated Gasification Combined-Cycle		
IGCC without carbon capture	300	Current
Nuclear		

Technology List	Gross Capacity (MW)	Data Start Date
Westinghouse - AP1000	960	Current

Source: KEMA

3.1.4. Community-Scale Technologies

Community-scale technologies will be discussed in the final project report.

3.1.5. Building-Scale Technologies

Building-scale technologies will be discussed in the final project report.

3.2. Biomass

3.2.1. Technology Overview

The use of biomass technology has been a part of the energy landscape for centuries and has become a technology of increasing importance in the current energy mix, both in California, the United States, and the rest of the world.

Biomass, or the use of plant-based hemi-cellulose material, agricultural vegetation, or agricultural wastes as fuel, has three primary technology pathways:

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

Of these technology pathways, the two primary embodiments of electricity production technology are found in the direct combustion and gasification approaches to biomass combustion into electricity and energy. Active research into pyrolysis for biofuel production is active and ongoing but is not yet at commercial scale.

Combustion technologies are widespread, and include the following general approaches:

- Stoker Boiler Combustion uses similar technology for coal-fired stoker boilers to combust biomass materials, either using a traveling grate or a vibrating bed. While a very mature, century-old technology, stoker boiler designs have seen technology improvements recently to improve biomass combustion, particularly emissions reductions and increased combustion efficiencies.

- Biomass-Cofiring uses biomass fuel burned with coal products in current technology pulverized-coal boilers used in utility-scale electricity production. Biomass cofiring is a mature technology in Europe and is increasingly being adopted in the United States, since it can significantly enhance the use of biomass, reduce net carbon emissions in power generation, and has shown good reliability in service.
- Fluidized Bed (FB) Combustion uses a special form of combustion where the biomass fuel is suspended in a mix of silica and limestone through the application of air through the silica/limestone bed. Fluidized bed combustion boilers are classified either as bubbling bed (FB) or circulating fluidized bed (CFB) units.

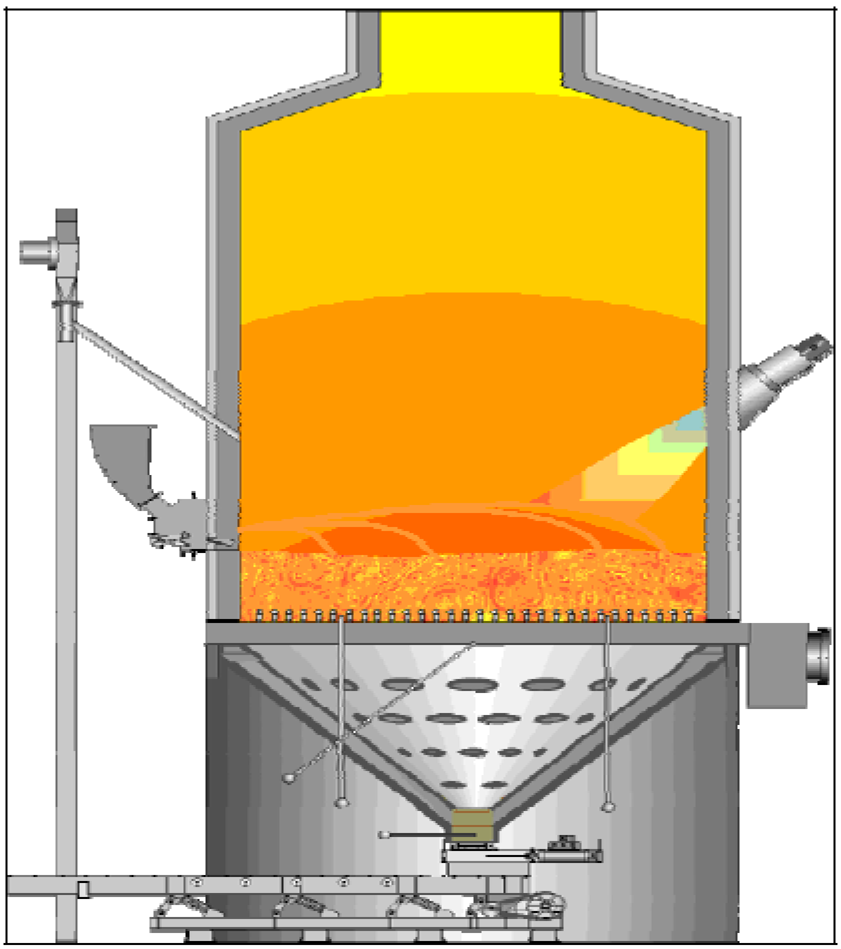

Figure 1. Utility-scale fluidized bed gasifier

Source: Energy Products of Idaho

Gasification technologies, while relatively recent in their evolution, are growing in scope and scale as they are increasingly being developed and used throughout the world. Several different forms of gasification technologies exist today:

- Biomass Integrated Gasification Combined-Cycle (IGCC) – similar to the coal-based IGCC process, except the biomass fuel is gasified in a reactor vessel prior to its introduction and combustion in a gas turbine generator set. Gas turbines developed for coal-based IGCC are well-suited for biomass IGCC because both gasified fuels are of sufficient BTU heating value content. Biomass IGCC plants are now being introduced as technology demonstration units.

Figure 2. Biomass IGCC plant representation
Source: KEMA

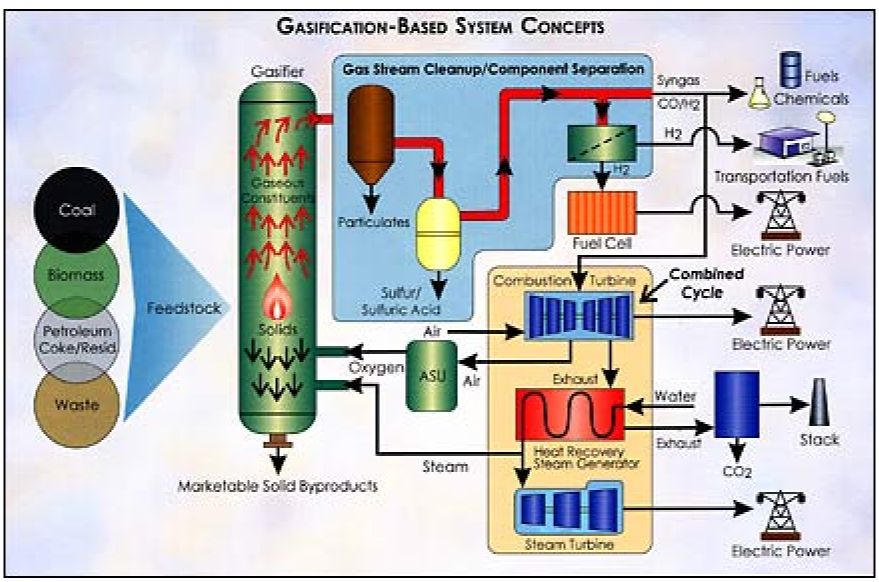

Figure 3. Schematic diagram of biomass IGCC process
Source: U.S. Department of Energy
(www.fossil.energy.gov/programs/powersystems/gasification/howgasificationworks.html)

- Biomass fluidized bed gasification – using a FB or CFB gasification reactor to convert biomass feedstocks into synthetic fuel gas, which is then burned in a conventional coal or natural gas-fired utility boiler. This technology is not being adopted for the cost of generation study because the current commercial embodiment is direct fluidized bed combustion of biomass for electrical power generation.

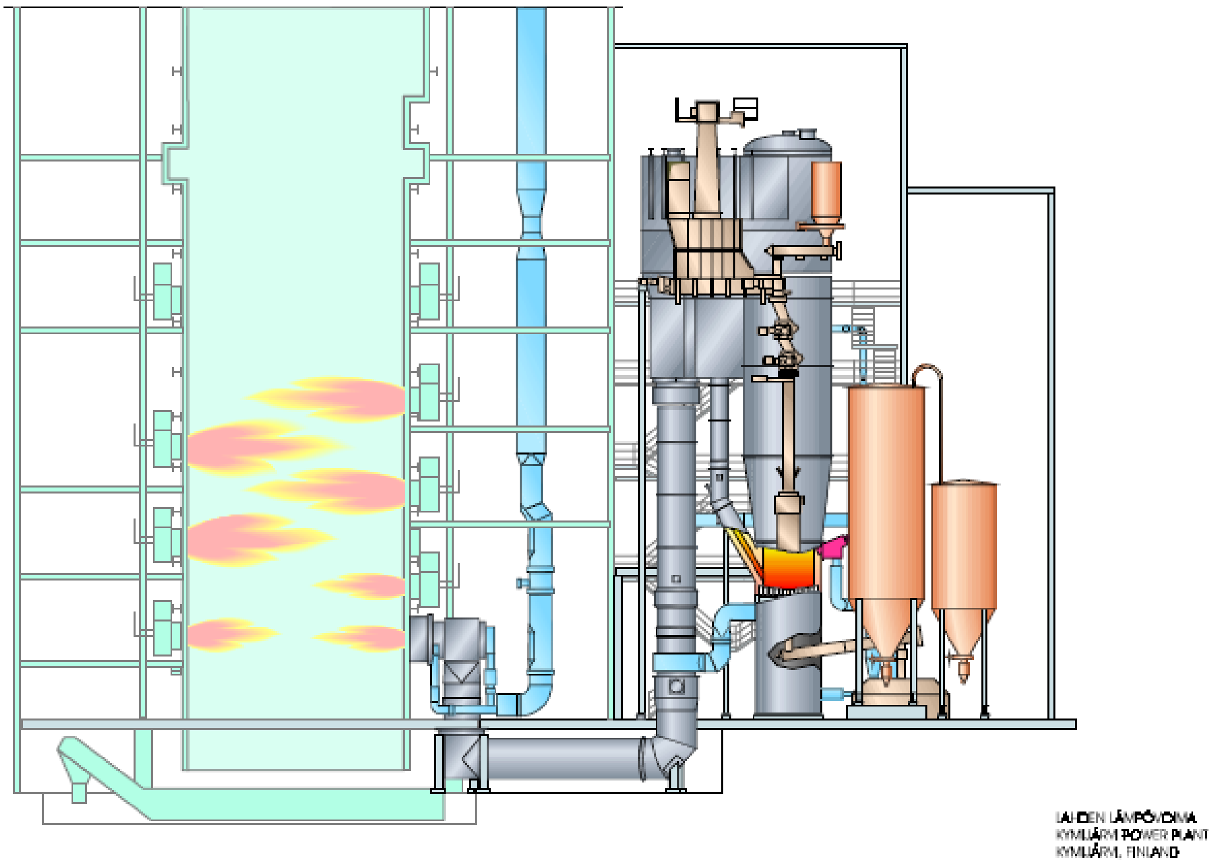

Figure 4. Utility-scale biomass fluidized bed gasifier
Source : Foster Wheeler

3.2.2. Biomass Combustion – Fluidized Bed Boiler

Technical and Market Justification

For biomass fuels, fluidized bed combustion is rapidly emerging as a system of choice for many power generation applications. The inherent fuel versatility of fluidized bed systems provides a plant operator the ability to burn many different biomass resource types, including those feedstocks with significant moisture variations. The major reason for this is that the fluidized bed carrying medium (typically a mix of silica sand and/or alumina) provides a thermal *flywheel* effect that maintains constant heat output and flue gas quality even when burning fuels of varying moisture content.[17]

Fluidized bed boilers are characterized as either bubbling bed (FB) or circulating fluidized bed (CFB), and this is based on how the bed material is used within the boiler. In a bubbling bed (FB) unit, the bed material stays within a fixed zone in the boiler, while in a circulating fluidized bed (CFB) unit, the material is suspended above an air zone and is circulated through a return loop back to the combustion zone by means of a mass or cyclonic separator.

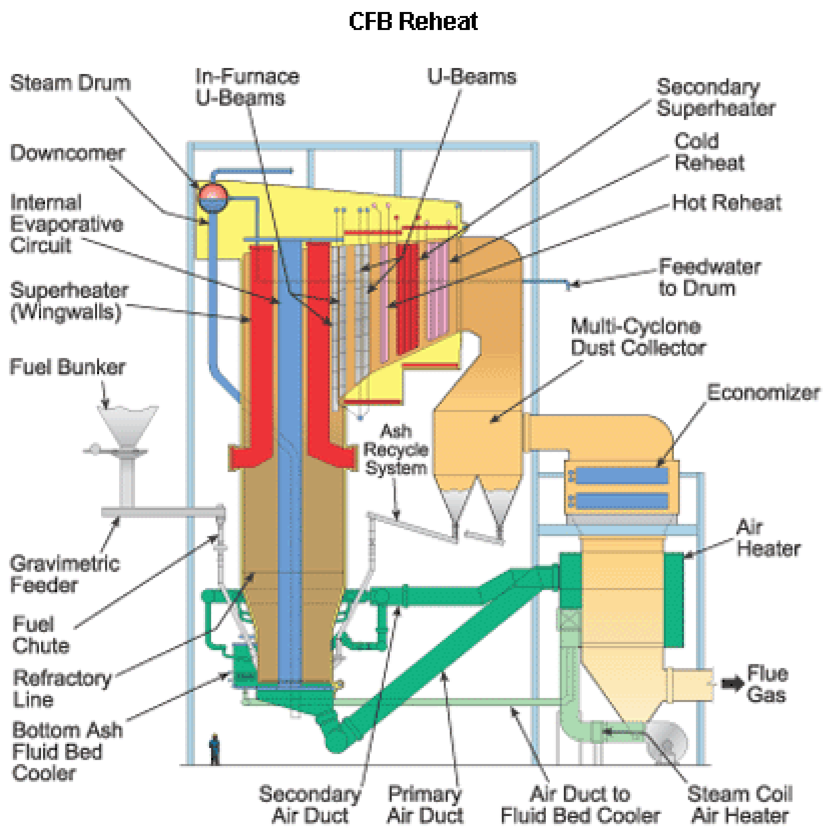

Figure 5. Circulating fluidized bed schematic diagram

Source: Babcock & Wilcox Image (www.babcock.com/products/boilers/images/cfb.gif)

For both FB and CFB units, due to the high quality combustion and near complete carbon burnout (99-100%) of biomass fuel sources, ash is carried over into the flue gas stream, requiring the addition of post-combustion ash removal equipment such as cyclones and baghouses. The

17 Overend, R.P. *Biomass Conversion Technologies*. Golden, CO: National Renewable Energy Laboratory, 2002.

post-combustion controls allow particulate removal to New Source Performance Standards (NSPS) for PM10.

Fluidized bed boiler technology has long been in commercial use, with much more widespread adoption in Europe than in the United States, due to several reasons.[18] First, fuel resources in Europe can vary widely in quality and processing, and the ability of fluidized bed boilers to handle widely varying fuels is of advantage. Second, fluidized bed boilers exhibit superior emissions performance, especially nitrogen oxide (NOx) emissions, due to the inherently low firing temperature of the boiler. Third, for coal-based fuels, the ability to directly inject limestone as a sorbent provides excellent sulfur and sulfur dioxide (SOx) reductions without the need for expensive post-combustion scrubbing equipment and systems.

Market adoption of fluidized bed boiler technology for biomass has long been a commercial reality, with both bubbling bed and CFB units being used for biomass cogeneration throughout the United States, particularly in the forest products and paper industry. Adoption of CFB technology for utility-scale coal and biomass power generation has reached worldwide general industry adoption, as shown below:

Table 7. Installed CFB boiler capacity by country[19]

Country	Installed Capacity (MW)
China	10,000
Czech Republic	1,400
Germany	1,800
Poland	3,310
India	1,200
United States	8,800

Source: Tavoulareas, Stratos. Advanced Power Generation Technologies – An Overview

Technology Selection Criteria

Fluidized bed combustion technology for generating electric power using biomass fuel was selected for the cost of generation study by the research team because of the following factors:

- Commercial scale – Both bubbling bed and circulating fluidized bed technologies have been developed to utility scale, and current commercialized units fit well within the overall supply curve constraints for biomass that can limit overall generating unit size potential.

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18 U.S. Environmental Protection Agency. Combined Heat and Power Partnership. *Biomass Combined Heat and Power Catalog of Technologies*, September 2007.

19 Tavoulareas, Stratos. *Advanced Power Generation Technologies – An Overview*. U.S. Agency for International Development. ECO-Asia Clean Development Program, August 2008.

- Fuel flexibility – Biomass combustion in fluidized bed boilers has been well documented for a variety of biomass fuel feedstocks. The inherent stability in fluidized bed boilers while burning fuels of varying quality is a key advantage when evaluating changing biomass fuel sources over the life of the generating plant.
- Reliability – Fluidized bed combustion is reliable and proven over decades of service. While relatively new in technology when compared to stoker- or traditional-fired boilers, there is rapid and growing adoption of fluidized bed boiler technology for mid-sized units.
- Emissions performance – Fluidized bed combustion performs well in reducing NOx emissions because of the low combustion temperatures used in the process. In addition, the near-complete conversion of available carbon results in lower carbon monoxide (CO) emissions. Particulate emissions are managed through post-combustion controls, as with traditional-fired units burning solid fuels.

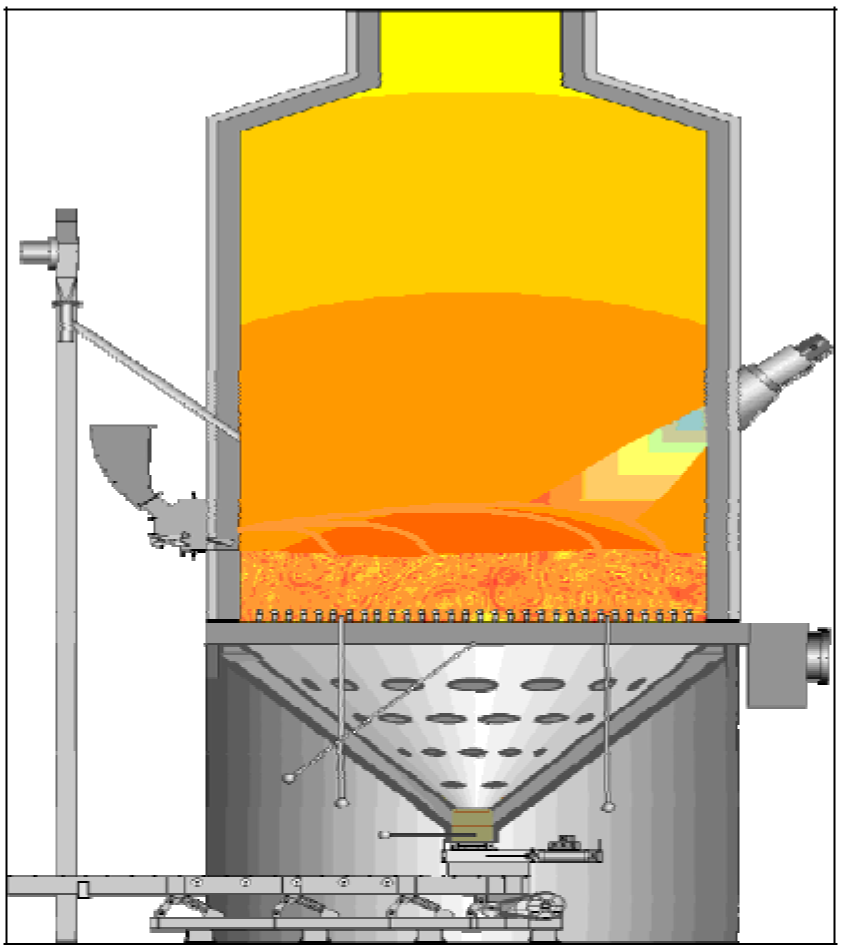

Figure 6. Bubbling fluidized bed boiler

Source: Energy Products of Idaho

Primary Commercial Embodiment

Today, the primary commercial embodiment of circulating fluidized bed boiler technology is in Europe and China and gaining momentum in the United States For over 20 years, the development of circulating and bubbling fluidized bed technology has progressed in Europe to the point where circulating fluidized bed boilers are a standard, utility-scale technology today. In the United States, several companies have progressed with standardized designs of circulating fluidized bed boilers combusting a variety of fuels, from biomass to coal and petroleum coke.

In California, current commercial embodiment is limited, mainly because of the limited ability to permit solid-fuel combustion facilities. However, there is current interest in the cogeneration and forest-products industrial base to examine fluidized bed combustion technology for repowering existing solid-fuel combustion facilities to biomass fuel conversion.[20]

The research team believes that fluidized bed technology will become commercially embodied in California to enable the state to achieve its biomass energy goals by 2018. The inherently fuel flexible nature of fluidized bed combustion, the integration of primary pollution controls into the combustion process, and the small footprint are enablers of this technology in California, as being demonstrated now in Europe and China.

Cost Drivers

Market and Industry Changes

Market and industry changes since August 2007 have not significantly affected costs for circulating fluidized bed boiler technology. Material cost increases have abated due to the current economic recession, especially in carbon steel and stainless steel costs, which are the primary cost components of circulating fluidized bed boiler manufacturing.

Carbon steel costs have changed significantly since August 2007, but the net change is not significant. The attached table highlights the rapid rise and then fall of carbon steel pricing:[21]

Table 8. Recent carbon steel pricing

Year	Average Carbon Steel Price ($/Ton)
2007	$717
2008	$1,004
2009 (April 2009 average annual price)	$736

Source: Purchasing Magazine

20 KEMA Sources :Personal Communication with EPI, Foster Wheeler, March 2009.

21 Purchasing Staff. "Steel plate prices have plunged 50% from mid-2008 peak." *Purchasing Magazine*. April 2009. www.purchasing.com/article/CA6654110.html?industryid=48389.

Current Trends

Current trends that will materially affect future costs are:

- Global economic downturn – The breadth and depth of the current recession has caused a significant reduction in the number of new boiler orders for both power generation and industrial manufacturing capacity. The length of the current recession and the pace of recovery will determine the escalation rate in raw materials, the use of boiler manufacturing capacity, and thus future costs.
- Steel price abatement – Current amelioration of worldwide steel prices, both for carbon and stainless steel, will have a price-moderating effect on stoker boiler prices both now and in the near future. Long-term steel commodity prices are currently difficult to predict.
- Industrial production and economic growth in China – By November 2008, China lost over 30 million manufacturing jobs in Guangzhou Province due to the global recession, significantly curtailing Chinese economic gross domestic product (GDP) growth. Enough of the global output for steel and other raw materials, used in circulating fluidized bed boiler production, were being used in China that significant escalation of prices resulted. The pace of the economic recovery and stimulus in China will determine raw material price escalation and thus will impact circulating fluidized bed boiler costs.
- Economic stimulus –Because stimulus packages are designed to support energy technologies, such as combined heat and power, cogeneration, and biomass, stimulus support in the United States could have an escalating effect on both materials and demand for circulating fluidized bed boilers.

Cost Drivers

Cost drivers for biomass circulating fluidized bed boiler technologies are as follows:

- Biomass fuel type and uniformity – The type and uniformity of delivered biomass fuel supply is a primary cost driver for any biomass technology. Because of the varied nature of biomass fuel feedstocks, their delivered moisture content and heating value variations, and fuel processing issues, the handling and processing costs of biomass fuels can vary greatly. As a result, the type and nature of biomass fuels combusted can have a material impact on the capital cost of the boiler island design, as well as the overall fuel handling and operations cost.
- Supply curve for biomass fuel, fuel transport and handling costs – The availability of adequate and sufficient biomass fuel resources within a 100-mile radius of the plant location is a critical driver for operating cost. Most biomass fuel is transported by truck transport to a plant site, which limits the effective economic radius from the plant location to aggregate fuel supply at commercially reasonable prices. The varied nature of biomass fuel feedstocks also necessitates special handling equipment and larger

numbers of dedicated staff than for coal-fired combustion power plants of equivalent size.

- Boiler island cost – Capital cost of the boiler island is a critical cost driver that can entail approximately 40-60% of the overall plant cost, depending on the type of biomass combusted and the need for post-combustion pollution controls.[22] The design basis for the type of fuels to be combusted is an important cost driver. In addition, the escalation trends for raw materials used in manufacture of the boiler island, primarily steel cost, are factors that can influence delivered boiler island cost.
- Long-term fuel supply contract availability – Most current biomass fuel supply contracts are of short-term duration and for fuel of sometimes varying quality. A key cost driver to promoting biomass circulating bed combustion in California is the ability to develop and achieve performance on long-term (e.g., five years duration and longer) fuel supply contracts for available fuel sources.
- Plant scale – Current CFB technology has been proven to utility-scale applications of up to 300 MW, with the primary commercial embodiment in sizes from 30-100 MW. Development of 800 MW class supercritical CFB cycles is now being studied for applications in China, and the outcome of that research effort would materially affect the capital cost profile and scale of CFB technology applications for biomass.[23]
- Emissions control costs – Costs especially of post-combustion emissions control technologies, such as SCR/SNCR technologies for NOx control, and additional particulate matter controls, are important cost drivers that can significantly increase the capital and operating costs of a commercial fluidized bed boiler combusting biomass.
- Retrofit versus greenfield/new site – For many biomass fluidized bed applications, repowering is a commercially viable option that can save 20-40% of the capital cost of a new greenfield site where all balance-of-plant systems would need to be constructed.
- O&M capitalization – The extent to which the long-term operations and maintenance of a biomass fluidized bed facility is capitalized through a long-term maintenance contract with an OEM supplier is a cost driver. These long-term maintenance contracts trade risk for maintenance cost predictability and can slightly change the operating cost profile of a commercial biomass fluidized bed boiler plant.

22 KEMA Sources: Personal Communication with Energy Products of Idaho, Coeur d'Alene, ID, March 2009.

23 Tavoulareas, Stratos. *Advanced Power Generation Technologies – An Overview.* U.S. Agency for International Development. ECO-Asia Clean Development Program, August 2008.

Current Costs

Current costs for biomass circulating fluidized bed boiler plants were primarily derived from three sources:

- Primary written research, reviewing the commercial embodiment of the technologies, and their instant and installed cost profiles.
- Research team direct communication with current technology manufacturers and developers of biomass CFB and bubbling bed plants.
- Research team direct experience in biomass and CFB plant development, construction, and operations, both in the United States and Europe.

The cost data gained through these three methods allowed for the comparison and contrast of capital and operating plant data and provided a detailed cost comparison for low/average/high cost case development.

Plant capacities for biomass fluidized bed boilers were established in a range of 15-70 MW, with 28 MW being the average plant capacity. The capacity range is primarily set by the effective biomass fuel supply range, along with the commercial embodiment of most biomass CFB designs today.

Capacity factors were modeled in the range of 75-90%, with 85% being the average value. These capacity factors are consistent with operational CFB boilers in commercial service.

Instant cost ranges for biomass CFB plants ranged from a low case of $1,600 per kilowatt (kW) to a high case of $4,800/kW, with an average CFB plant cost of $3,200/kW. These instant costs can vary widely due to a number of factors: type of fuel and fuel mix burned, size/scale of the plant, whether the site is a brownfield redevelopment or a greenfield site, and the amount of post-combustion pollution controls needed to satisfy air quality and permitting requirements. Typically, the boiler island comprises 40-60% of the total instant plant cost.

Heat rates are similar to those of other solid-fuel technologies, ranging from 9,800 British thermal units (Btu) per kilowatthour (kWh) to 11,000 Btu/kWh, with 11,500 Btu/kWh being used as the average. Heat rates can vary for biomass CFB systems due to fuel moisture content and heating value.

Expected Cost Trajectories

Cost trajectories for biomass fluidized bed boiler technology were developed through examination of several factors.

Capital cost and installation duration for a fluidized bed plant provide the largest trajectory difference. In all cases, the research team assumed a biomass fluidized bed plant is developed by a merchant generator, as there are few applications worldwide that have been developed for cogeneration purposes, either in the forest/paper industries, the MSW industries, or for enhanced oil/gas recovery.[24] Construction periods were set for either a two or three-year construction cycle, mostly dependent on permitting approvals and receipt of air quality approvals.

Determination of installed costs were derived from examining interest costs during construction, plus the range in expected construction costs for the low, average, and high cases.

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

3.2.3. Biomass Combustion – Stoker Boiler

Technical and Market Justification

Stoker boilers have been used for solid fuel combustion and power generation for over a century. Generally used for small-scale power generation under 100 MW in size, the primary stoker boiler technology types for biomass are moving grate and encompass traveling grate, vibrating grate, and spreader stoker variants of the technology.

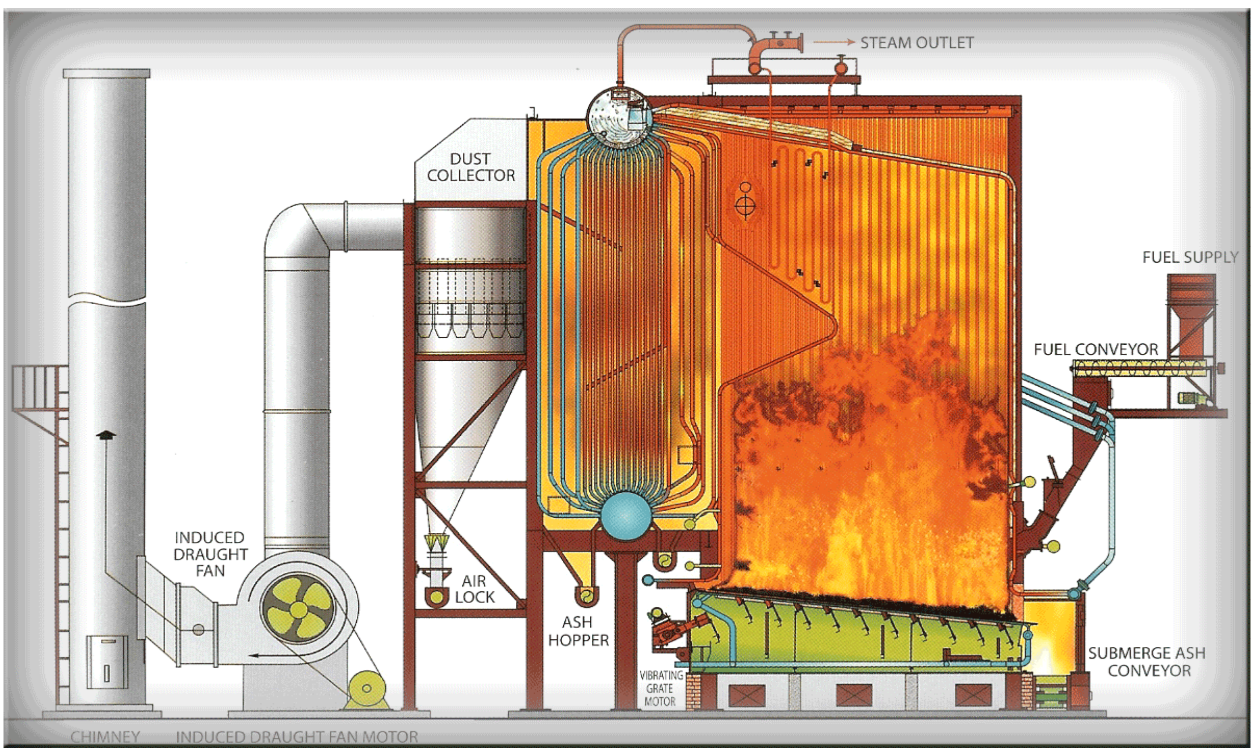

Figure 7. Stoker boiler schematic diagram

Source: Boilermech, (www.boilermech.com)

24 California Biomass Collaborative. *California Biomass Facilities Reporting System*, March 2009. http://biomass.ucdavis.edu/tools.html.

Biomass-fired stoker boiler technology has evolved to provide reliable, efficient combustion and energy generation. Today, modern biomass stoker combustion systems provide an efficient, stable combustion process while supplying the desired boiler heat input with low emissions:

- Efficient combustion – Produces efficient use of the biomass feedstock fuel supply through burning with low carbon monoxide (CO) emissions and low unburned carbon (UBC), which is an indicator of combustion efficiency.
- Stable combustion – Produces stable and consistent combustion to maintain consistent design parameters and boiler performance, even with changing biomass fuel supply mix.
- Heat input – Generates the heat input to support the power generation cycle.
- Low emissions – Produces low carbon monoxide, low unburned carbon (UBC), and low nitrogen oxides (NOx).[25]

Modern stoker designs have improved significantly over vintage boilers installed pre-1965, when the majority of commercial stoker boilers were installed.[26] Today's biomass stoker boilers have improvements that enhance their ability to burn biomass feedstocks of varying quality and type:

- Improved fuel feed controls and distribution of biomass across the grate – Provide more uniform heat release in the boiler, improving consistency and reliability of operation.
- Improved combustion air distribution – Improves efficiency and emissions performance, particularly NOx and CO emissions.
- Advanced overfire air systems – Complete combustion, improving efficiency and emissions performance and reduces unburned carbon and char when burning biomass fuels.
- Reduced excess air requirements – Improve combustion efficiency.
- Improved fuel/air mixing through better furnace gas path design and use of grate oscillation – Improves efficiency and reliability of furnace parts.[25]

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25 Abrams, Richard F. and Kevin Toupin. "Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Marketplace." POWER-GEN Renewable Conference Technical Publication, March 2007.

26 Gas Research Institute (GRI). *Analysis of the Industrial Boiler Population*. Energy and Environmental Analysis, Inc., June 1996.

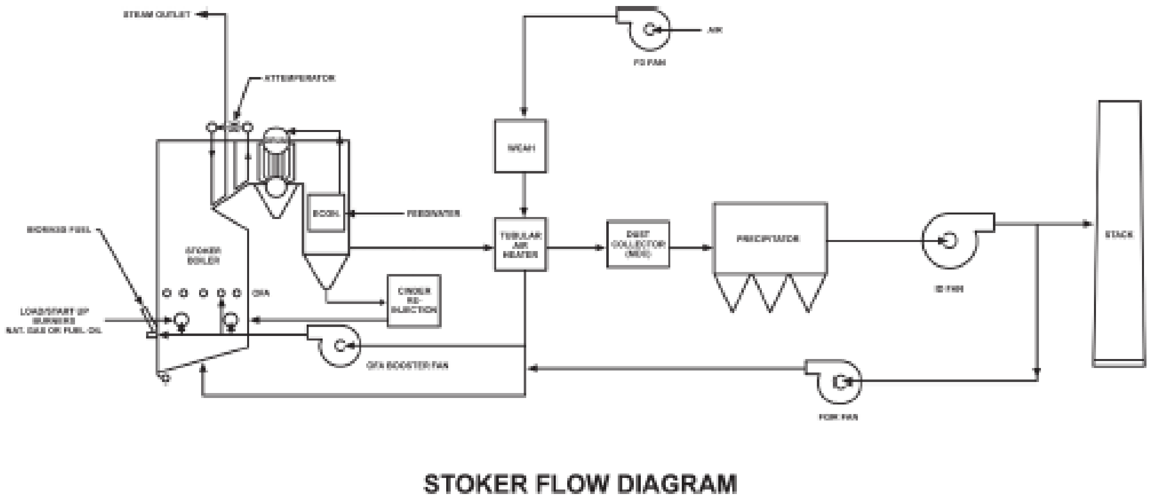

Figure 8. Flow schematic for a stoker boiler configuration

Source: DeFusco, McKenzie and Fick, "Bubbling Fluidized Bed or Stoker." [27]

Primary Commercial Embodiment

Currently, California has approximately 30 solid-fuel biomass facilities in the state, totaling 640 MW of generation. The vast majority of these plants are stoker boilers, installed in the 1970s and 1980s after the Public Utility Regulatory Policies Act (PURPA) came into effect, and serve primarily the forest products, pulp and paper, and waste-to-energy cogeneration markets. These plants operate reliably and effectively, although California has seen a decline in the number of solid-fuel biomass plants due to two reasons: cost of biomass fuel supplies and more stringent emissions legislation in the state.

The primary commercial embodiment of the stoker boiler technology is not expected to change significantly by 2018, but the research team expects continuing improvements in fuel combustion technology to reduce emissions and increase fuel flexibility. In addition, the research team found improved post-combustion emissions controls, such as selective catalytic reduction (SCR), and Riley's selective catalytic reduction (RSCR™) – a combination of a regenerative thermal oxidizer and SCR. RSCR technology is significantly more thermally efficient than standard SCR technologies, providing NOx removal at much lower annual fuel costs.[28]

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27 DeFusco, John, Phillip McKenzie, and Michael Fick. "Bubbling Fluidized Bed or Stoker – Which is the Right Choice for Your Renewable Energy Project." CIBO Fluid Bed Combustion XX Conference, May 2007.

28 Abrams, Richard F. and Kevin Toupin . "Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Marketplace." POWER-GEN Renewable Conference Technical Publication, March 2007.

Cost Drivers

Market and Industry Changes

Market and industry changes since August 2007 have not significantly affected costs for stoker boiler technology. Material cost increases have abated due to the current economic recession, especially in carbon steel and stainless steel costs, which are the primary cost components of stoker boiler manufacturing.

Carbon steel costs have changed significantly since August 2007, but the net change is not significant. The attached table highlights the rapid rise and then fall of carbon steel pricing:[29]

Table 9. Recent carbon steel pricing

Year	Average Carbon Steel Price ($/Ton)
2007	$717
2008	$1,004
2009 (April 2009 average annual price)	$736

Source: Purchasing Magazine

Current Trends

Current trends that will materially affect future costs are:

- Global economic downturn – The breadth and depth of the current recession has caused a significant reduction in the number of new boiler orders for both power generation and industrial manufacturing capacity. The length of the current recession and the pace of recovery will determine the escalation rate in raw materials, the use of boiler manufacturing capacity, and thus future costs.
- Steel price abatement – Current amelioration of worldwide steel prices, both for carbon and stainless steel, will have a price-moderating effect on stoker boiler prices both now and in the near future. Long-term steel commodity prices are currently difficult to predict.
- Industrial production and economic growth in China – By November 2008, China lost over 30 million manufacturing jobs in Guangzhou Province due to the global recession, significantly curtailing Chinese economic gross domestic product (GDP) growth. Enough of the global output for steel and other raw materials used in stoker boiler production was being used in China that significant escalation of prices resulted. The pace of the economic recovery and stimulus in China will determine raw material price escalation and thus will impact stoker boiler costs.
- Economic stimulus – Because stimulus packages are designed to support energy technologies such as combined heat and power, cogeneration, and biomass, stimulus

29 Purchasing Magazine Staff. "Steel Plate Prices Have Plunged 50% From Mid-2008 Peak." *Purchasing Magazine*, April 2009. www.purchasing.com/article/CA6654110.html?industryid=48389.

support in the United States could have an escalating effect on both materials and demand for stoker boilers.

Cost Drivers

Cost drivers for stoker-fired biomass combustion boiler plants are as follows:

- Biomass fuel type and uniformity – The type and uniformity of delivered biomass fuel supply is a primary cost driver for any biomass technology. Because of the varied nature of biomass fuel feedstocks, their delivered moisture content and heating value variations, and fuel processing issues, the handling and processing costs of biomass fuels can vary greatly. As a result, the type and nature of biomass fuels combusted can have a material impact on the capital cost of the boiler island design, as well as the overall fuel handling and operations cost.
- Supply curve for biomass fuel, fuel transport, and handling costs – The availability of adequate and sufficient biomass fuel resources within a 100-mile radius of the plant location is a critical driver for operating cost. Most biomass fuel is transported by truck transport to a plant site, which limits the effective economic radius from the plant location to aggregate fuel supply at commercially reasonable prices. The varied nature of biomass fuel feedstocks also necessitates special handling equipment and larger numbers of dedicated staff than for coal-fired combustion power plants of equivalent size.
- Boiler island cost – Capital cost of the boiler island is a critical cost driver that can entail approximately 40-60% of the overall plant cost, depending on the type of biomass combusted and the need for post-combustion pollution controls.[30] The design basis for the type of fuels to be combusted is an important cost driver. In addition, the escalation trends for raw materials used in manufacture of the boiler island, primarily steel cost, are factors that can influence delivered boiler island cost.
- Long-term fuel supply contract availability – Most current biomass fuel supply contracts are of short-term duration and for fuel of sometimes varying quality. A key cost driver to promoting biomass combustion in California is the ability to develop and achieve performance on long-term (e.g., five years duration and longer) fuel supply contracts for available fuel sources.
- Emissions control costs – Costs especially of emissions control technologies, such as advanced overfire air or SCR/SNCR technologies for NOx control and additional

30 KEMA Sources: Personal Communication with Energy Products of Idaho, Coeur d'Alene, ID, March 2009.

particulate matter controls, are important cost drivers that can significantly change the capital and operating costs of a commercial stoker boiler combusting biomass.[31]

- Retrofit versus greenfield/new site – For many biomass fluidized bed applications, repowering is a commercially viable option that can save 20-40% of the capital cost of a new greenfield site where all balance-of-plant systems would need to be constructed.

Current Costs

Current cost profiles for stoker boiler biomass combustion technology were developed using three primary research methods:

- Primary written research, reviewing the commercial embodiment of the technologies and their instant and installed cost profiles.
- Research team direct communication with current technology manufacturers and developers of biomass-fired stoker boiler plants.
- Research team direct experience in biomass stoker combustion plant development, construction, and operations, specifically referencing a stoker boiler biomass plant in St. Paul, Minnesota.

Stoker-boiler technology is considered a mature technology, with stoker designs having changed little in basic design or cost profile over a period of 40 years. Most of the design innovation being performed today in stoker technology is to upgrade the performance of stoker boilers to combust a wide range of biomass fuels (formerly, biomass fuels being combusted in a stoker boiler had to be relatively uniform in type and heat/moisture content), and to improve emissions control performance.[32]

Capital costs and sizes for stoker boilers were developed through direct communication with manufacturers, including Riley and Energy Products of Idaho. In addition, these costs were verified and contrasted with the *Biomass Combined Heat and Power Catalog of Technologies* reference document, compiled by the U.S. Environmental Protection Agency (EPA) Combined Heat and Power Partnership.[33]

Net capacity factors for stoker boilers can vary depending on the type of fuel source used, the variation in the fuel, and operating requirements of the plant. In general, stoker boilers burning

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31 Abrams, Richard F. and Kevin Toupin . "Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Marketplace." POWER-GEN Renewable Conference Technical Publication, March 2007.

32 Power Engineering, "Efficient and Low Emission Stoker-Fired Biomass Boiler Technology in Today's Marketplace." *Power Engineering*, March 2007.

33 U.S. Environmental Protection Agency. Combined Heat and Power Partnership. *Biomass Combined Heat and Power Catalog of Technologies*, September 2007.

biomass have fewer capacity factors than if the boilers were using coal as fuel, with the primary reason being the larger variation in biomass fuel properties going to the stoker grate and the variation of the biomass fuel source over time. Capacity factors of 75%, 85%, and 90% were used based on fleet experience for the high-cost, average-cost, and low-cost cases, respectively.

Plant capital cost data was examined through the construction of an average sized 38 MW plant, and scaled accordingly for the high and low-cost cases, based on experience and actual plant data. For the low-cost case, reference data from a prior retrofit site was used, and for the high cost case, scaling factors from manufacturers detailing the range in cost estimates were used.[34]

Plant heat rates were modeled using an average 40-50% moisture woody biomass fuel feedstock and current stoker technology. Heat rate ranges are from 10,250 – 13,000 Btu/kWh, with an average heat rate of 11,000 Btu/kWh modeled. The research team notes that performance, ultimate capacity, and heat rate are strongly dependent on the biomass fuel type selected, its variation in combustion and moisture properties over time, and the mixing of biomass fuel sources. Moisture, for instance, is a key variable in determining biomass stoker performance because the energy used in heating and vaporizing the moisture content in the fuel is not recovered fully and thus negatively impacts overall performance.

Expected Cost Trajectories

Cost trajectories for biomass stoker boiler technology were developed through examination of several factors.

Capital cost and installation duration for a stoker plant provides the first and largest trajectory difference. In all cases, the research team assumed a biomass stoker plant, developed by a merchant generator, as the vast majority of stoker applications are developed for cogeneration purposes in California, either in the forest/paper industries, the MSW industries, or for enhanced oil/gas recovery.[35] Construction periods were set for either a two- or three-year construction cycle, mostly dependent on permitting approvals and receipt of air quality approvals.

Determination of installed costs were found through the interest costs during construction, plus the range in expected construction costs for the low, average, and high cases. Expected installed costs for 2009 for the low, average, and high cases are:

Table 10. Biomass stoker installed cost ranges – 2009 dollars per kW installed

Low Case	Average Case	High Case
$ 1,914 /kW	$ 2,909 /kW	$4,050/kW

Source: KEMA

34 KEMA Communication with Energy Products of Idaho, and direct experience with Market Street Energy project, St. Paul, MN, March 2009.

35 California Biomass Collaborative. *California Biomass Facilities Reporting System*, March 2009 (http://biomass.ucdavis.edu/tools.html).

Very little experience curve learning effects were modeled in the expected cost trajectories. The U.S. Department of Energy shows stoker combustion technology as a very mature technology and with little incremental improvement foreseen through 2030.[36] A maximum learning rate of 5% through 2030 was modeled, along with a low-case rate reflecting no learning through 2030 was modeled for the high case.

3.2.4. Biomass Cofiring

Technical and Market Justification

One of the most attractive and easily implemented renewable energy sources is derived from cofiring of biomass in existing coal fired boilers. In biomass cofiring, up to 20%-30% of the coal can be displaced by biomass. The biomass and coal are combusted simultaneously. The term *biomass* refers to materials derived from plant matter such as trees, grasses, and agricultural crops. These materials, grown using energy from sunlight, can be renewable energy sources for fueling many of today's energy needs. Cofiring projects replace a portion of the nonrenewable fuel–coal–with a renewable fuel–biomass.

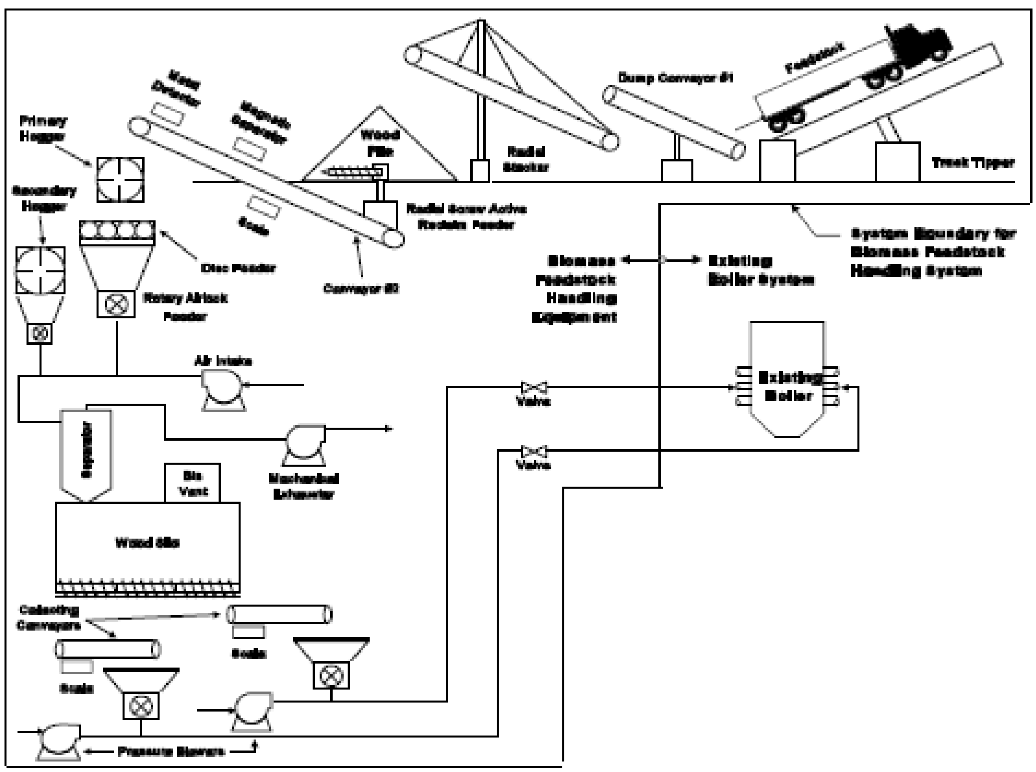

Figure 9. Biomass cofiring schematic for a pulverized coal boiler system

Source: U. S. Department of Energy, Energy Efficiency and Renewable Energy

36 U.S. Department of Energy. Energy Information Administration. Office of Integrated Analysis and Forecasting. *Learning Parameters for New Generation Technology Components*.

When it is used as a supplemental fuel in an existing coal boiler, biomass can provide the following benefits: lower fuel costs, more fuel flexibility, avoidance of waste to landfills and their associated costs, and reductions in sulfur oxide, nitrogen oxide, and greenhouse gas emissions. Other benefits such as decreases in flue gas opacity have also been documented.

Cofiring is a proven technology. Over the past 15 years, the research team has found extensive experience with direct and indirect cofiring of several types of biomass fuels. KEMA has tested cofiring mixtures of coal and several biomass fuels up to about 25% (on an energy basis) in KEMA's 1 MW test boiler and has been involved in over 50 full-scale commercial and demonstration projects in coal-fired power plants. In addition, many utilities have cofiring biomass in coal-fired generation plants, as noted in the following table:[37]

Table 11. Coal-fired generation plants with biomass cofiring

Facility Name	Company	City/County	State	Capacity (MW)	Heat Input from Biomass (Percent of Total)
6th Street	Alliant Energy	Cedar Rapids	IA	85	7.7
Bay Front	Xcel Energy	Ashland	WI	76	40.3
Colbert	TVA	Tuscumbia	AL	190	1.5
Gadsden 2	Alabama Power	Gadsden	AL	70	<1.0
Greenridge	AES	Dresden	NY	161	6.8
C.D. Mcintosh, Jr.	City of Lakeland	Polk	FL	350	<1.0
Tacoma Steam Plant	Tacoma Public Utilities	Tacoma	WA	35	44.0
Willow Island 2	Allegheny Power	Pleasants	WV	188	1.2
Yates 6 and 7	Georgia Power	Newnan	GA	150	<1.0

Source: Haq, Zia. Biomass for Electricity Generation

The Electric Power Research Institute (EPRI) began research and testing of biomass cofiring in utility boilers in 1992, and with success cofiring biomass percentages of up to 40% of fuel requirements. In Europe, the Netherlands has undertaken extensive studies of biomass cofiring of up to 30% of boiler fuel requirements. Biomass cofiring is currently a valid commercial technology for coal-fired utility-scale power plants, having been tested in a wide range of boiler types, including cyclone, stoker, pulverized coal, and fluidized bed boilers.[38]

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37 Haq, Zia, *Biomass for Electricity Generation*. U.S. Department of Energy. Energy Information Administration, 2002.

38 U.S. Environmental Protection Agency. Combined Heat and Power Partnership. *Biomass Combined Heat and Power Catalog of Technologies*, September 2007.

Biomass cofiring technology is versatile and can be accomplished in several ways, depending on the percentage of biomass to be cofired with coal, and the design of the specific boiler system. In general, there are four main routes to successfully accomplish cofiring, as shown in the diagram below:

- Co-milling of biomass with coal.
- Separate milling, injection in pf-lines, combustion in coal burners.
- Separate milling, combustion in dedicated biomass burners.
- Biomass gasification, syngas combusted in furnace boiler.

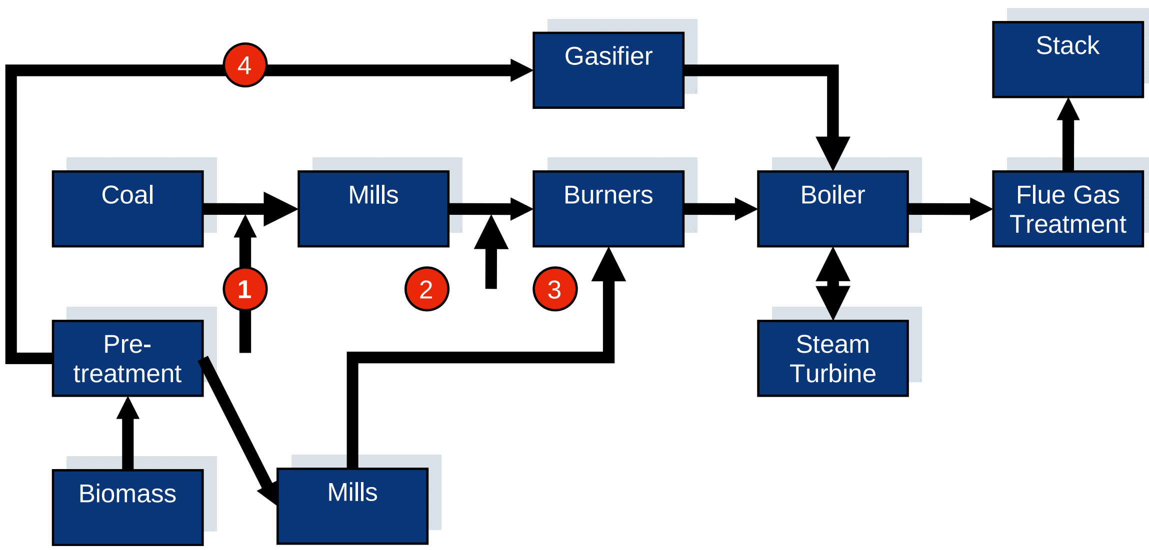

Figure 10. Primary biomass cofiring locations
Source: KEMA, Inc.

Co-milling of biomass with coal, and separate milling and injection/combustion into the coal burners are the most common route for biomass cofiring when the overall percentage of biomass to coal is relatively small (<15%). In these applications, the biomass blends well with a predominantly coal mixture, and is combusted in the boiler with little operational impact.

For larger percentages of cofiring with biomass, typical applications will require the addition of separate feed streams of the biomass, along with the addition of dedicated biomass burners. These boiler modifications are needed because of the differing characteristics and heating values of the fuel (biomass – 9000 Btu/lb, versus coal – 12,000 Btu/lb), and the varying feedstock quality that can often be found in biomass fuel supply.

In addition, a fourth route to cofiring biomass is to gasify it, usually in a fluidized bed gasifier, and then combust the synthetic gas in the furnace with dedicated gas burners. This approach is increasingly gaining market acceptance, particularly with the successful commercial operation of fluidized bed gasifiers, and is a driving technology behind the retrofit of older technology biomass stoker plants.[39]

Primary Commercial Embodiment

The primary commercial embodiment of biomass cofiring technology in California is found in two forms:

- Addition of biomass cofiring to the small number of remaining utility-scale coal boilers in California, typically up to 30% cofiring. In addition, biomass cofiring is feasible in the WECC region coal-fired plants that currently export generation and energy to California.
- Addition of biomass cofiring to the existing small utility-scale coal boilers in operation (20-50 MW), of which there are approximately 30 plants that currently exist, and approximately 66 plants feasible if currently closed biomass facilities are repowered.

By 2018, the primary commercial embodiment is predicted by the research team to be similar to the current state, with incremental operating improvements gained by additional cofiring experience. The research team notes that several companies are looking at their current biomass cofiring experience to be an interim step towards complete fuel switching from coal to 100% biomass fuel, as climate change legislation appears more likely before 2018.

Cost Drivers

Market and Industry Changes

Since August, 2007, there has been additional industry experience with cofiring biomass due to emissions legislation in the United States, plus continued emphasis on biomass cofiring implementation in the European Union. These industry changes have helped cofiring gain additional momentum as a useful generation technology addition for carbon reduction and climate change mitigation strategies. As of this report, these industry changes have not had a discernable impact on market prices for cofiring adoption.

Current Trends

Currently, biomass cofiring is one of the most inexpensive ways to increase use of biomass feedstocks and fuel sources. Requiring only a fraction of the investment capital for new plant, the research team believes it is a technology with significant potential to help biomass become competitive in the energy landscape.

Cost Drivers

Cost drivers for biomass circulating fluidized bed boiler technologies are as follows:

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39 Energy Products of Idaho, Cœur d'Alene, ID.

- Biomass fuel type and uniformity – The type and uniformity of delivered biomass fuel supply is a primary cost driver for any biomass technology. Because of the varied nature of biomass fuel feedstocks, their delivered moisture content and heating value variations, and fuel processing issues, the handling and processing costs of biomass fuels can vary greatly. As a result, the type and nature of biomass fuels combusted can have a material impact on the capital cost of the boiler cofiring upgrades, as well as the overall fuel handling and operations cost. For biomass cofiring, the amount of biomass cofiring and uniformity of the fuel can affect the operating combustion and temperature profiles in the boiler, and thus the overall cost of boiler improvements.[40]
- Supply curve for biomass fuel, fuel transport, and handling costs – The availability of adequate and sufficient biomass fuel resources within a 100-mile radius of the plant location is a critical driver for operating cost. Most biomass fuel is transported by truck to a plant site, which limits the effective economic radius from the plant location to aggregate fuel supply at commercially reasonable prices. The varied nature of biomass fuel feedstocks also necessitates special handling equipment and larger numbers of fuel handling personnel than for a similarly sized coal-fired plant.
- Boiler island capital upgrade cost – Capital cost of necessary boiler modifications, depending on the cofiring fuel injection point is a critical cost driver that can entail approximately 50% of the overall capital upgrade cost, depending on the type of biomass combusted and the location of the biomass cofiring injection point.[41] In addition, the escalation trends for raw materials used in manufacture of the boiler fuel feed and pressure parts, primarily steel cost, are factors that can influence the final installed cost of cofiring upgrades to the boiler.
- Long-term fuel supply contract availability – Most current biomass fuel supply contracts are of short-term duration and for fuel of sometimes varying quality. The ability to write and achieve performance on long-term (e.g., five years duration and longer) fuel supply contracts for available fuel sources is a key cost driver to securing additional biomass cofiring generation.
- O&M capitalization – The extent to which the long-term operations and maintenance of boiler upgrades required to support a high (>10% biomass cofiring) level of biomass cofiring is capitalized through a long-term maintenance contract with an OEM supplier is a cost driver. These long-term maintenance contracts trade risk for maintenance cost predictability, and can slightly change the operating cost profile of a commercial boiler plant cofiring both coal and biomass fuels.

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40 Dayton David, *A Summary of NOx Emissions Reduction From Biomass Cofiring*. National Renewable Energy Laboratory, May 2002.

41 KEMA Sources: Personal Communication with Energy Products of Idaho, Coeur d'Alene, ID, March 2009.

Current Costs

Current costs were developed by examining the biomass cofiring technology within the context of operation of current coal-fired utility-scale boiler technology, coupled with the experience base of cofiring biomass both in Europe and in the United States. Plant scale was developed by using the 5-30% general cofiring ranges seen in current applications, and especially those successfully demonstrated in the United States.[42] Capacities used in the model ranged from 10 - 40 MW gross capacity due to biomass cofiring, and incremental to the nominal coal-fired output of the boiler plant.

Capacity factors modeled were from 85-95%, reflecting current test burn and operational experience showing that there is not a detrimental availability impact caused by cofiring biomass within the nominal 5-30% ranges.

Efficiency and heat rate ranges were also chosen based on nominal increases to heat rate due to moisture content of the fuel, but otherwise tracked current coal-plant industry heat rates. Heat rate ranged from 9,800 Btu/kWh to 12,000 Btu/kWh, with an average heat rate modeled at 10,500 Btu/kWh.

Capital requirements for the cofiring technology were based on both current industry experience combined with the research team experience base in cofiring biomass in the Netherlands. Instant (overnight) capital cost ranges were modeled between 400 – 700 $/kW, with an average of $500/kW. All boiler modifications for cofiring technology are assumed to be constructed within one year.

Expected Cost Trajectories

The type of boiler modifications and technologies involved in biomass cofiring are extremely mature technologies involving burner modifications, injection point rework, and fuel handling systems. Based on the maturity of these technologies, very little experience curve effects are anticipated, and only small incremental improvements in cost performance are foreseen by the research team. A technology progress ratio for biomass cofiring of 0.990 was assigned to this technology based on the similarities of cofiring technologies to established solid-fuel cofiring and test burn technology applications. The progress ratio indicates that, with a doubling of the installed biomass cofiring capacity, one would expect a 1% improvement in cost performance over time.

The overall cost performance of biomass cofiring technologies is expected to track the rate of inflation over the long run.

3.2.5. Biomass Co-Gasification IGCC

Technical and Market Justification

Biomass co-gasification IGCC is a unique technology that has many commercial utility-scale applications. Biomass IGCC draws upon the technology base used to develop and

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42 Blume, Grant, Ronald Meijer, and Kevin Sullivan, "Cofiring of Biomass in the US." Renewable Energy World Conference Presentation, March 2009.

commercialize coal-based IGCC plants beginning with the first commercial scale utility unit at Duke Energy's Wabash River Generating Station in 1995. Since that time, both coal and biomass-based IGCC has been commercialized as a viable generating technology, with key advantages:

- Feedstock flexibility – Because the combined-cycle unit is fired with synthetic gas from the gasifier units, a variety of fuel feedstocks, from coal to petroleum coke and biomass, can be used.
- Low emissions – Similar to a natural gas-fired combined-cycle unit and much lower than solid-fueled coal units.
- Carbon capture – IGCC cycles are particularly suitable for carbon capture and sequestration, since carbon dioxide is emitted in separate streams that may be captured and disposed in a normal process cycle.

The key approach to the IGCC cycle application for biomass fuels is the ability of current generation gas turbines to accept and burn low-BTU content gas streams. This technology shift has happened over the last 15 years, and now most modern gas turbine engines will combust biomass-based syngas in turbine size ranges suitable for most biomass development plant scales.[43]

The first successful demonstration project for biomass co-gasification IGCC was in Varnamo, Sweden, and ran from 1992 through 2000 at 18 MW combined heat and power output.[44]

As of 2007, the biomass gasification market counted 13 active biomass gasifiers from companies worldwide, encompassing four major technology types:[45]

- Atmospheric pressure circulating fluidized bed gasifier – In commercial operation at Lahti, Finland, producing 42 MWe since 1998, and using biofuels, RDF (refuse derived fuel), and wood waste as biomass feedstocks.
- Pressurized circulating fluidized bed gasifier (PCFB) – Demonstrated at Varnamo, Sweden, through 2000, and producing 6 MWe using wood, RDF and straw as biomass feedstocks.
- Plasma gasifier – Demonstrated at Utashinai, Japan, in 2003, producing 8 MWe in commercial operation, using a downward moving bed and plasma bottom torch.

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43 Overend, Ralph P. *Biomass Conversion Technologies*. Golden, CO: National Renewable Energy Laboratory, March 2002.

44 Stahl, Krister, Lars Waldheim, Michael Morris, Ulf Johnsson, and Lennart Gårdmark. "Biomass IGCC at Varnamo, Sweden – Past and Future." GCEP Energy Workshop, April 2004.

45 Cobb, James T. "Survey of Commercial Biomass Gasifiers." University of Pittsburgh, AIChE Annual Meeting, November 2007.

- Draft type – original technology, and not generally suitable for gas turbine applications because of tar carryover.

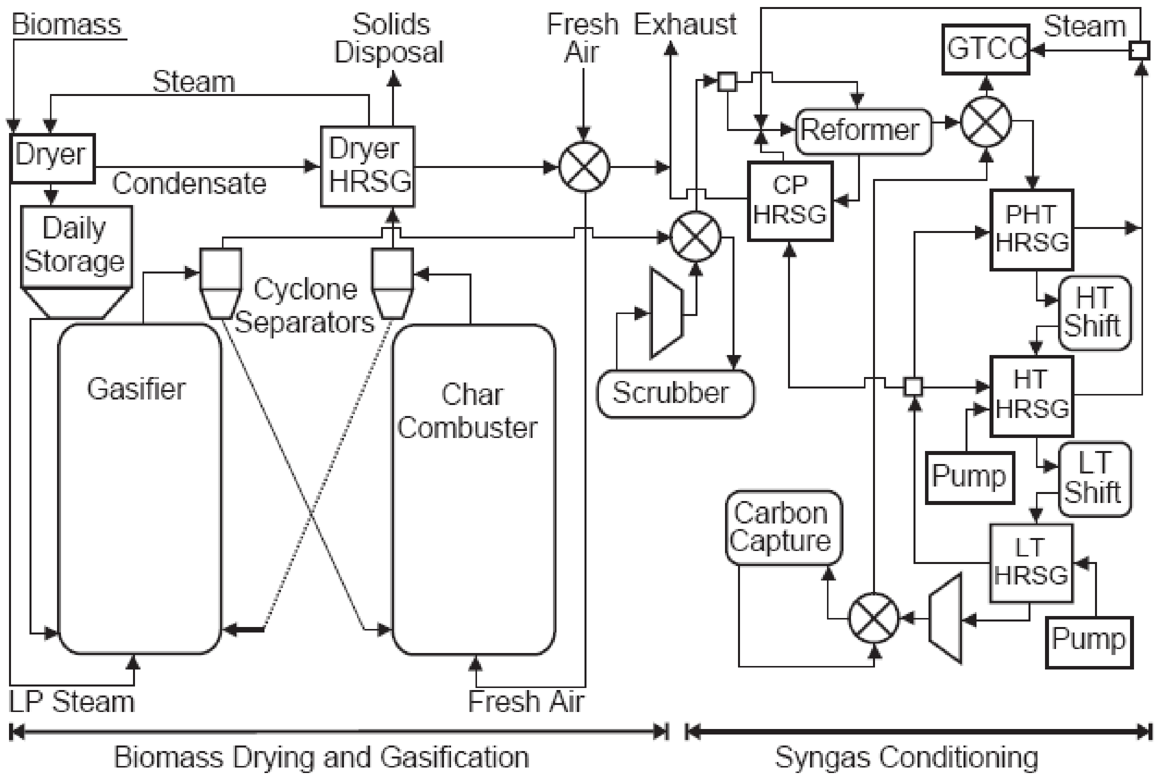

Figure 11. Process flow diagram for biomass gasification and conditioning for IGCC application

Source: Rhodes and Keith, "Engineering economic analysis of biomass IGCC."[46]

Primary Commercial Embodiment

Currently, there is no primary commercial embodiment in California, as the use of biomass IGCC has not yet been commercialized. However, the basic premise of coal-based IGCC is a commercial technology, and in the United States, utility-scale coal-based IGCC plants are being developed with the capability to cofire biomass feedstocks in limited percentages (<15%).

By 2018, the research team expects the biomass IGCC technology to become commercialized, with CFB gasifier technology as the leading approach for biomass IGCC development.

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46 Rhodes, James S. and David W. Keith. "Engineering Economic Analysis of Biomass IGCC With Carbon Capture and Storage." *Biomass and Bioenergy* 29 (2005): 440-450.

Cost Drivers

Market and Industry Changes

Market and industry changes since August 2007 have favored the rapid development of utility-scale biomass IGCC plants. The first change in the market is pending climate change legislation that will impose a cap-and-trade system for carbon dioxide and other GHG emissions. This change will drive technology development to those approaches that can capture and sequester carbon, as well as carbon-neutral approaches to power generation. Biomass IGCC, because of the near-zero carbon emission profile of biomass fuels, coupled with the ability to capture carbon dioxide, is an ideal technology for a carbon-constrained power generation market.

Second, the increased deployment of coal-fired IGCC units, such as the recently announced repowering project at Duke Energy's Edwardsport station in Indiana, will further the development of gasification reactor technology. Gasifier trains will be tested and technology developed to reliably gasify biomass feedstocks along with coal.

Third, active research in biomass gasification and co-gasification with coal is being conducted in Europe, particularly in the Netherlands, where biomass co-gasification experiments of up to 50% biomass by weight are being conducted at two power stations.[47]

Current Trends

Future costs for biomass co-gasification will be driven by the development of commercial gasifier trains that are able to handle wide variations in biomass feedstock materials. As these technologies become more mature, experience effects will drive down the overall capital cost of these plants.

Cost drivers for biomass integrated gasification combined-cycle plant technologies are as follows:

- Biomass fuel type and uniformity – The type and uniformity of delivered biomass fuel supply are primary cost drivers for any biomass technology. Because of the varied nature of biomass fuel feedstocks, their delivered moisture content and heating value variations, and fuel processing issues, the handling and processing costs of biomass fuels can vary greatly. As a result, the type and nature of biomass fuels combusted can have a material impact on the capital cost of the fuel handling systems and the gasifier process trains. Fuel variability in the gasification process can alter process properties, and result in changes to the required gasifier size.[48]
- Supply curve for biomass fuel, fuel transport and handling costs – The availability of adequate and sufficient biomass fuel resources within a 100-mile radius of the plant location is a critical driver for operating cost. Most biomass fuel is transported by truck

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47 KEMA sources and research.

48 Murphy Michael, *Repowering Options: Retrofit of Coal-Fired Boilers With Fluidized Bed Biomass Gasification*. Energy Products of Idaho, 2001.

to a plant site, which limits the effective economic radius from the plant location to aggregate fuel supply at commercially reasonable prices. The varied nature of biomass fuel feedstocks also necessitates special handling equipment and larger numbers of fuel handling personnel than for a similarly sized coal-fired plant.

- Boiler/gasifier capital costs and trajectory – The primary driver in determining overall costs is the capital costs and long-run cost trajectories for the gasifier trains required to gasify biomass fuel feedstocks. After several decades of commercial development and embodiment of the technology in coal-gasification applications, the technology is considered relatively mature, and few scale effects are anticipated. In addition, the escalation trends for raw materials used in manufacture of the gasifier plant, primarily steel and alloy steel cost, are factors that can influence the final installed cost of installing biomass gasification technology.
- Long-term fuel supply contract availability – Most current biomass fuel supply contracts are of short-term duration and for fuel of sometimes varying quality. The ability to write and achieve performance on long-term (e.g. five years duration and longer) fuel supply contracts for available fuel sources is a key cost driver to securing financing for more expensive biomass gasification projects.

Current Costs

Gross capacity ranges between 25-40 MW were modeled for biomass gasification combined-cycle units, primarily reflecting the effective size range and fuel supply radius for sourcing biomass fuel feedstocks. These ranges also embody current project sizes now under development in California, though not yet built, and they also fall readily within currently available fluidized bed gasification technologies.

Net capacity factors are modeled as between 65-80%, reflecting the on-stream expected times of gasifier train units processing biomass fuel, coupled with the expected availability of the gas turbine combined-cycle generation units.

Instant costs were modeled based on direct conversations with active developers reviewing projects in California, combined with industry costs for fluidized bed gasifier trains supporting between 25-40 MW class plants, and existing industry combustion turbine combined-cycle data. These costs in total average $2,950/kW, with a high range of $3,688/kW and a low range of $2,655/kW modeled. High case costs reflect additional capital cost for biomass fuel variation characteristics, and low case costs reflect simpler fuel processing and handling costs.

Construction durations for total installed cost calculations range from one to three years duration, with the average plant constructed within a two-year time horizon.

Plant efficiency and heat rate were modeled based on the overall expected performance of the gas turbine combined-cycle coupled with the gasifier train operating as a fluidized bed unit. Overall heat rates between 10,000 – 11,000 Btu/kWh were modeled by the research team, with an average expected heat rate of 10,500 Btu/kWh.

Expected Cost Trajectories

Expected cost trajectories for biomass IGCC development will track closely the technology progress for coal-based integrated gasification technologies. Those technologies are considered mature after over two decades of commercial development and embodiment, and significant experience curve effects are not anticipated to reduce overall installed cost base.

The research team used a modified technology progress ratio range of 0.98 to 1.00 to model biomass integrated gasification combined-cycle experience curve trajectories, as this technology has matured in the coal-based environment in which it has developed. Some sources characterize additional learning curve effects with the gasifier train development, of up to a 10% learning curve improvement in the period after 2020, but the research team did not incorporate this view into the analysis for cost trajectory development.[49] The rationale is that the expected embodiment of this technology in California will be primarily bubbling and circulating fluidized bed gasifier trains, and this technology is well-established for gasifying biomass fuels. Other technologies currently under development for coal fuel feedstocks would need additional development to handle the widely varying characteristics common to biomass, and this resulted in a selection of a more conservative learning rate for this technology by the research team.

3.3. Geothermal

3.3.1. Technology Overview

Geothermal energy is derived from heat from beneath the Earth's surface that flows to the surface through a variety of pathways from hot water, steam reservoirs, or heated rock formations. Heat is carried continuously upward to the Earth's surface as steam or hot water when water flows through permeable rock. California has the largest geothermal megawatt production and potential of any state. Currently, only a fraction of California's enormous geothermal resources are used. Approximately 94% of all known United States hydrothermal resources are located in California.

Currently in the United States, geothermal energy accounts for approximately 2,850 megawatts of electric power, enough electricity for 3.7 million people. The cost of producing this power ranges from 4 to 8 cents per kWh. The nation's electrical power generation was estimated at 80 quadrillion Btu (quads) in 1990. Of this amount, renewable energy produced 6.4 quads in 1990 or 8% of the nation's total energy consumption. It is estimated that renewable energy sources have the potential to supply as much as 36.6 quads by 2030. Geothermal resources are predicted to be the largest short-term supplier of renewable electric power, with more than a tenfold increase or 3.3 quads projected by 2010. This is approximately 35% of the calculated renewable energy contribution.

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49 U.S. Department of Energy. Energy Information Administration. *Learning Curve Effects for New Technologies*.

Types of Geothermal Resources

Most geothermal resources fall into one of the following categories: vapor-dominated, liquid-dominated, geopressure, hot dry rock, and magma. Geothermal resources result from a concentration of the Earth's thermal energy within regions of the four subsurface types. Of these resources, only vapor- and liquid-dominated resources have been developed commercially for power generation.

Vapor-Dominated Resources

Vapor-dominated resources contain superheated steam above 200°C (382°F) and are rare in nature. The resources have been proven to be economical to exploit for electricity generation. In California the only vapor-dominated resource, known as The Geysers, is located in Northern California. The Geysers is a low-pressure, single-phase system.

Liquid-Dominated Resources

In California liquid-dominated geothermal fields are more common than vapor-dominated resources. In general, in liquid-dominated reservoirs liquid water at high temperature and high pressure fills fractured and porous geology and may form a small steam cap within the reservoir. In these geothermal systems, water migrates into a well from the reservoir by a path of least resistance. In California, liquid-dominated resources are quite abundant and far more widespread than vapor-dominated resources. Over 90% of known geothermal resources are liquid-dominated. Liquid-dominated resources are characterized by the presence of either hot water or saturated steam (a mixture of steam and hot water) with reservoir temperatures ranging from 25°C (77°F) to over 315°C (599°F).

High temperature resources (reservoirs with temperatures greater than 176°C [349°F]) generally use flashed steam or total flow power generation systems. At resource temperatures lower than 176°C, these technologies become inefficient and economically unattractive, in which case, the binary cycle system is more appropriate. A binary cycle plant can use moderate temperature resources (reservoirs with temperatures between 104°C [219°F] and 176°C) 40% to 60% more efficiently than a flashed steam facility.

Earth Energy (Geothermal Heat Pumps and Direct Use)

Earth energy is the heat contained in soil and rocks at shallow depths. This resource is tapped by geothermal heat pumps. The soil and near-surface rocks, from 5 to 50 feet deep, have a nearly constant temperature (10°C [50°F] to 70°C [10°F] depending on latitude) from geothermal heating. According to the U.S. Environmental Protection Agency, geothermal heat pumps are one of the nation's most efficient heating, cooling, and water-heating systems available. In winter, these systems draw on "earth heat" to warm the house, and in summer they transfer heat from the house to the earth. Underground reservoirs are also tapped for *direct-use* applications. In these instances, hot water is channeled to greenhouses, spas, fish farms, and homes for space heating and hot water.

Vapor-Dominated Resource Development

The development of vapor-dominated geothermal was initiated in 1960 at The Geysers through a partnership of Union Oil Company of California (Unocal) and Magma Energy Company.

Thermal Power Company produced steam to the Pacific Gas and Electric Company (PG&E) electrical power generation grid. Since 1960, The Geysers has developed into the world's largest dry steam resource with over 2700 MW of installed electrical generating capacity.

The Geysers is the largest developed vapor-dominated system in the world and the only known dry steam resource in the United States In a dry steam system, the reservoir contains dry, superheated steam with average temperatures generally exceeding 200°C (392°F). These resources are used exclusively for electricity generation and have proven to be economical.

Power plants operating in The Geysers use dry steam produced from numerous wells. The steam is piped to the turbine generator through extensive collection systems. The steam exiting the turbine is condensed with cooling water and pumped to evaporative cooling towers. The temperature of the condensate is further reduced, producing the cooled water used in the turbine exhaust condenser. The remaining condensate is injected back into the ground. During this process, however, 80% to 85% of the geothermal fluid is lost through evaporation.

Since 1960, when commercial electricity generation first began, The Geysers has become the premier geothermal development in the world. Since the mid 1980s, The Geysers reservoir has begun to exhibit the effects of heavy steam withdrawal. Steam pressure, particularly in the central part of the reservoir, has dropped much faster than was originally expected. In many existing wells, steam pressure has declined from the initial 500 pounds per square inch (psi) in 1960 to less than 200 psi, shortening their useful life and hastening the need for make-up wells. But, in many instances, the additional supply of steam provided by new make-up wells has proven to be insufficient to maintain the original steam output. Also, many of the steam developers are encountering production interference. That is, steam that would otherwise be produced from an existing well is diverted to a new well.

The dramatic decline in output from many of the plants at The Geysers is very serious. Since 1986, electricity production has fallen by as much as 40%. The production forecasts are projected to be 11,000 MW, nearly one-half of the current capacity. This situation might be reversed if sufficient water is found to recharge the reservoir by injection. This condition is due to cumulative overproduction. Current estimates suggest that less than 5% of the reservoir heat has been extracted from The Geysers.

The Geysers is the only dry steam field that is commercially developed in the nation and has successfully produced power since the early 1960s. Today, The Geysers retains a peak capability of nearly 1,100 MW, enough electricity to supply a city of over a million Californians.

As The Geysers resource was expanded, resource exploration and research in areas outside The Geysers accelerated. At The Geysers, additional generating capacity was installed. Additional dry steam plants had considerable larger capacity increases and larger turbines, which required more production and injection wells that resulted in more expensive steam production lines and greater operation and maintenance costs.

The Geysers geothermal field reached maximum steam production of 1,866 MW in 1988. Since then, pressure and production rates have declined. Steam production decline has demonstrated the importance of increased water injection to maintain reservoir pressure. While there is continuing research toward determining the best methods for water injection, mitigation efforts–such as the construction of the Santa Rosa and southeast Geysers pipeline projects to augment fluid injection to offset production declines–are underway. Other activities that have been implemented include modifications to plant operations for increasing efficiency. In addition, operation of older, less efficient power plants has been suspended and steam rerouted to newer and more efficient plants. Plant operators have installed new turbines designed at lower turbine inlet pressures. Operators have also modified the design and operations of existing turbines, condensers, and gas-handling systems for low-load and cycling. These changes may extend the life of the resource but at a higher price.

The Geysers is a resource that is now intensively managed for steam production. Since the steam decline became noticeable in 1985, approximately 200 MW of production have been taken off-line or suspended. The geothermal electricity generation industry has watched the unfolding of events at The Geysers and has responded by constructing closed-cycle systems that reinject virtually everything extracted out of the ground. Reinjection of spent steam has been successful in slowing reservoir steam declines but has not proven to increase steam production.

Geothermal resources developments are now being planned with more caution than before, to avoid a scenario similar to the one at The Geysers. The elimination of competition between steam producers and plant operators has eased as a result of ownership consolidation and changing auction strategies. Reservoir management activities such as further spacing of production and injection wells, as well as monitoring water resources for flow, quantity, chemistry, and tendencies toward brine and scaling are also being implemented. As a result, binary and liquid-dominated flash extraction systems are the only ones being installed today.

Liquid-dominated Resource Development

Geothermal exploration of liquid-dominated resources in California began in 1967, when both Unocal and Morton Salt Company deployed small, experimental geothermal turbines operating at the Salton Sea field. However, problems with silica scaling and high salt concentrations prevented commercial development of the resource at that time. In developing liquid-dominated resources during the 1970s, developers had to consider the degree of risk, greater capital costs, an adverse regulatory climate, and relative immaturity of the exploration, drilling, and production technology, which impeded the development of liquid-dominated resources. These impediments were mitigated significantly when the federal and state government responded to the oil crisis of 1973. To encourage exploitation of geothermal resources and associated technologies, the Energy Commission and the DOE provided financial assistance programs to support R&D in these areas.

Development of liquid-dominated resources was further facilitated in 1975, when the U.S. Geological Survey (USGS) concluded a nationwide geothermal resource assessment. The USGS assessment document was instrumental in expanding interest in developing liquid-dominated resources in the Southwestern states.

Several years later, the Federal Energy Regulatory Commission (FERC) encouraged development of geothermal resources by providing energy tax credits and loan guaranties while establishing a more progressive regulatory process through passage of the Public Utility Regulatory Policy Act (PURPA) of 1978. By 1979, FERC had formulated regulations for implementation of PURPA. In essence, FERC directed state regulators to require that utilities purchase power from independent power producers (IPPs) at the utility's full avoided cost and to make the utility's transmission system available to deliver the power to market. The FERC decision that utilities could be required to pay the quality factor, a capacity charge as well as an energy charge was significant to the geothermal industry. The logic for the capacity charge was that, because of the baseload nature of geothermal power, its sale to the utility directly displaced capacity that utilities would otherwise have to build in the future.

This action led to the Energy Commission requiring utilities to issue Standard Offer Number Four (SO-4) contracts for purchase of power from IPPs. This resulted in the signing of long-term contracts, setting prices at the utility's full avoided cost for new baseload capacity. The result of these regulatory and financial incentives resulted in a shift from utility development of a dry steam resource to independent development of liquid-dominated resources at multiple locations throughout the state. This trend established the IPP segment of the industry and increased its power generating capacity from zero to approximately one-third of the total MW production. Production from liquid-dominated resources is also approximately one-third of total production.

The initial electrical power development of a liquid-dominated geothermal resource occurred in November 1979 at the East Mesa field in Imperial County. The electrical generation plant consisted of a binary application using isobutane as the secondary working fluid to turn out 13.4 MW of electrical power.

In June 1980, Southern California Edison (SCE) began operation of a 10 MW experimental power plant at the Brawley geothermal field with steam produced by Unocal. However, SCE and Unocal ceased further development of the field after a few years of operation due to corrosion, reservoir uncertainties, and the high salinity brines that typically produced salts by mass that ranged between 5% and 25%.

In the mid 1970s, Unocal, in conjunction with the DOE, spearheaded research and development and plant operation activities at the Geothermal Loop Experimental Facility at the Salton Sea geothermal field. Unocal took the lead role in developing and resolving problems that were encountered in processing the high salinity brines, which were typically over 20% salt by mass. The Geothermal Loop Facility was completed in 1976 and was designed to determine the technical feasibility of removing salts that formed when steam was flashed from the brine. As a result of this cooperative industry/government effort, a crystallizer clarifier, a brine treatment process, was developed and demonstrated. This process was critical in proving that commercial power generation was technically and economically feasible from the Salton Sea geothermal field.

Unocal initiated electrical power generation from the Salton Sea geothermal resource in June 1982 from its 12 MW plant. In 1982, Unocal added two additional generation units for a total gross electrical generation of 83 MW.

In late 1985, Magma Power Company commenced continuous production from its first 40 MW power plant at the Salton Sea field. Within a couple years, Magma added three more generating units that brought its total to 145 MW. Today, the entire Salton Sea field operation of eight power plants with 288 MW capacity is operated by CalEnergy Corporation, which bought out Unocal's and Magma's operations. In January 1999, CalEnergy Operating Corporation unveiled a $400 million expansion of their geothermal power complex at the Salton Sea.

To generate electricity economically using liquid-dominated resources, reservoir temperatures generally must exceed 104.4°C (220°F). There are several areas within California where liquid-dominated resources above this temperature are being developed. These include the Imperial Valley, Coso Hot Springs, Mono-Long Valley, and Wendel-Amadee. Other areas that exhibit temperatures above this minimum and where exploration has begun include Glass Mountain, Lassen, and Surprise Valley. Since the temperature and quality of these resources vary significantly from site to site, different types of generating systems are needed, depending on the specific circumstances. In the Imperial Valley, there are 16 plants operating with a combined capacity of 527.3 MW. At the Coso Hot Springs resource there are nine dual flash operating plants with a combined gross rating capacity of 229.5 MW.

In a flashed steam systems, geothermal brine, typically between 104°C and 176°C, is brought to the surface and piped to a separation tank where the pressure is reduced, causing the fluid to flash into steam. In a single flash system, fluid is allowed to boil at the surface in one stage production separation. A fraction of the hot water "flashes" to steam when exposed to the lower pressure within the separator. The steam is then passed through a turbine to generate power. Typically, the liquid fraction is then injected back into the reservoir. During this process as much as 60% of the usable heat extracted from the reservoir may be lost. To improve efficiency, dual flash systems are used in which the geothermal fluid is flashed twice, increasing the amount of steam to the turbine. Dual flash technology imposes a second stage separator onto a single flash system. This second stage steam has a lower pressure and is either put into a later stage of a high pressure turbine or a second lower pressure turbine. The steam exiting the turbine is condensed in much the same manner as with dry steam plants. However, less of the resource is lost during evaporative cooling since less than half of the geothermal water that is produced actually flashes to steam. Double flash technology is in the range of 10% to 20% more efficient than single flash technology.

This study includes two types of geothermal power plants:

- Binary Power Plants (Figure 12).
- Flash Power Plants (Figure 13).

Dry steam plants are not included in this cost of generation study since they are only applicable to one resource in the western United States (The Geysers). For the purposes of costs modeling, resources applicable to a wider geography were chosen.

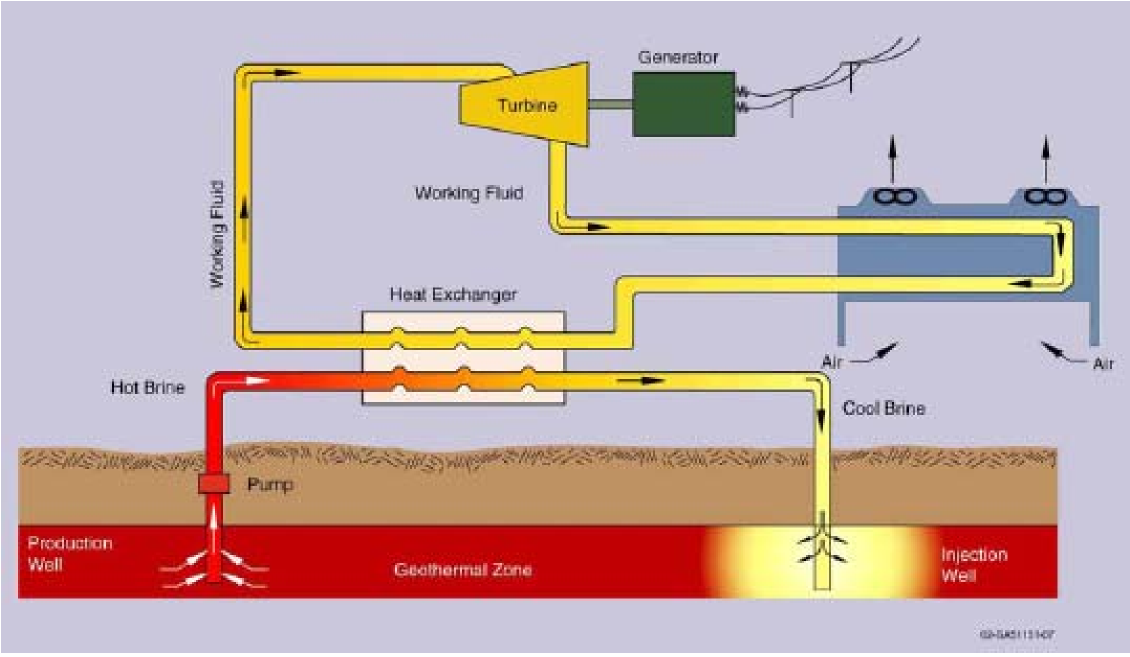

Figure 12. Binary power plant
Source: Idaho National Laboratory

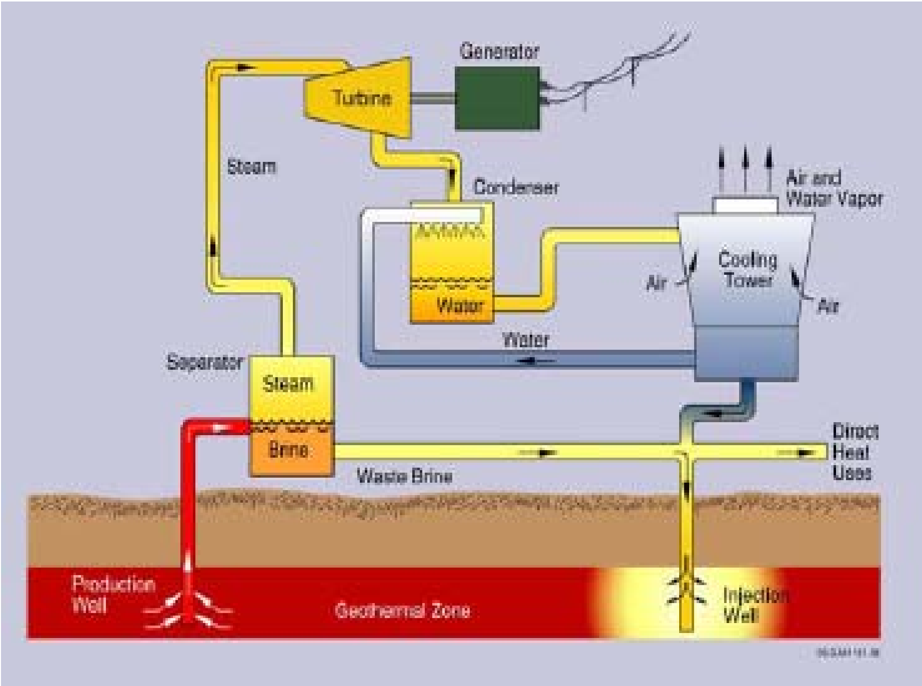

Figure 13. Flash power plant
Source: Idaho National Laboratory

3.3.2. Geothermal – Binary

Technical and Market Justification

Current California binary geothermal installations total 140 MW.[50] An additional 240 MW potential development[51] is likely using binary technology.

Primary Commercial Embodiment

Binary cycle geothermal power plants pass moderately hot geothermal water (called brine) by a secondary fluid with a much lower boiling point than water. This causes the secondary fluid to flash to vapor, which then drives the turbines. California binary plants range in size from 0.7 to 47.8 MW with most between 20 and 30 MW. Each of these plants can have several generators. The average generator size in use in California is approximately 4 MW.

The typical binary geothermal power plant in 2018 is foreseen to be similar in function and size to the current installations.

Cost Drivers

Much of the information on cost drivers is common to both binary and flash geothermal plants. Common information between the two technologies is not repeated in the flash geothermal section.

Market and Industry Changes

There have been no market and industry changes since August 2007 that have materially affected geothermal technologies.

Current Trends

Binary geothermal is a mature technology with plants in California since the mid 1980s. A number of specific sites have been identified in California suitable for binary plant development. Should these sites be developed, the less expensive sites (greatest return on investment) would be first, with the more expensive sites to follow. Any learning curve in development would most likely be a cost avoidance rather than a cost saving. Therefore any cost reduction trends are unlikely to be seen.

Cost Drivers

Geothermal plants include the following key cost drivers:[52]

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50 Source: http://geoheat.oit.edu/directuse/power.htm

51 Sison-Lebrilla, Elaine, Valentino Tiangco. *Geothermal Strategic Value Analysis*. CEC-500-2005-105-SD, June 2005.

52 Kagel, Alyssa. *A Handbook on the Externalities, Employment, and Economics of Geothermal Energy*. Geothermal Energy Association, October 2006.

- Exploration – Includes defining the geothermal resource.
- Confirmation – Seeks to confirm the energy potential of a resource by drilling production wells and testing their flow rates until about 25% of the resource capacity needed by the project is confirmed.
- Site development – Covers all remaining activities that bring a power plant on-line.
    - Drilling – The success rate for drilling production wells during site development average 70% to 80%. The size of the well and the depth to the geothermal reservoir are the most important factors in determining the drilling cost.
    - Project leasing and permitting – Like all power projects, geothermal must comply with a series of legislated requirements related to environmental concerns and construction criteria.
    - Piping network – The network of pipes connecting the power plant with production and injection wells. Production wells bring the geothermal fluid (or *brine*) to the surface to be used for power generation, while injection wells return the used fluid back to the geothermal system to be used again.
    - Power plant design and construction – In designing a power plant, developers must balance size and technology of plant materials with efficiency and cost effectiveness. The power plant design and construction depend on type of plant (binary or flash) as well as the type of cooling cycle used (water or air cooling).
    - Transmission – Includes the costs to include the construction of new lines, upgrades to existing lines, or new transformers and substations.

Another important factor is operation and maintenance (O&M), which consist of all costs incurred during the operational phase of the power plant. Below is a brief description:[53]

- Operation costs consist of labor, spending for consumable goods, taxes and royalties, and other miscellaneous charges.
- Maintenance costs consist of keeping equipment in good working status and steam field maintenance. Besides maintaining the production injection wells (pipelines, roads, etc.), expenses related to steam field maintenance mainly involve make-up drilling activities. Make-up drilling aims to compensate for the natural productivity decline of the project start-up wells by drilling additional production wells.

Cost drivers are not constant for every single geothermal site development. Each of the above drivers can vary significantly based on specific site characteristics. Other key variable factors that drive costs for geothermal plants (not mentioned directly above since they are highly project specific) are project delays, temperature of the resource, and plant size.

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53 Hance, Cedric *Factors Affecting Costs of Geothermal Power Development*. Geothermal Energy Association, August 2005.

Project delays can significantly impact the exploration cost of geothermal development. Figure 14 shows an estimation of this cost impact.[53]

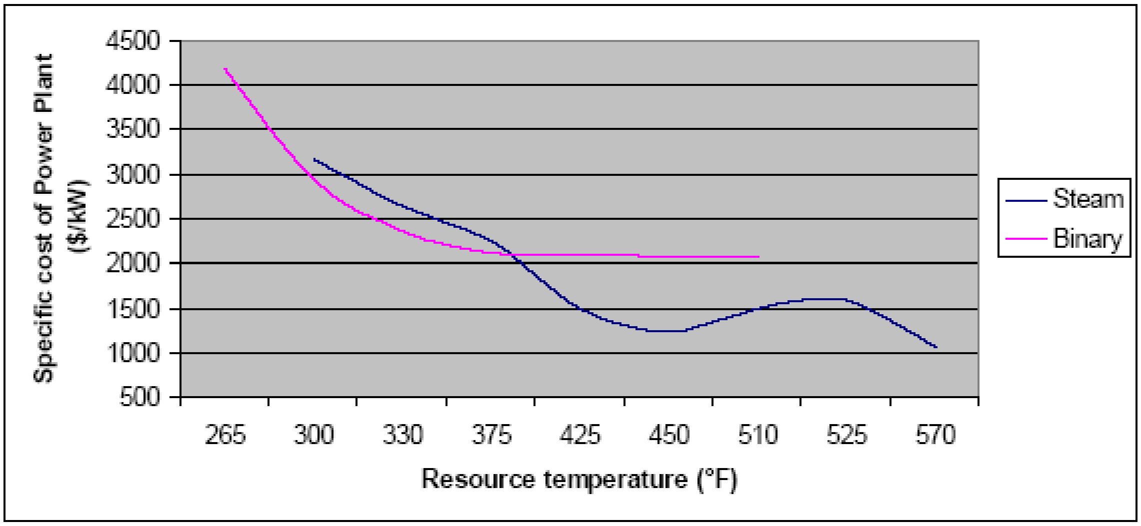


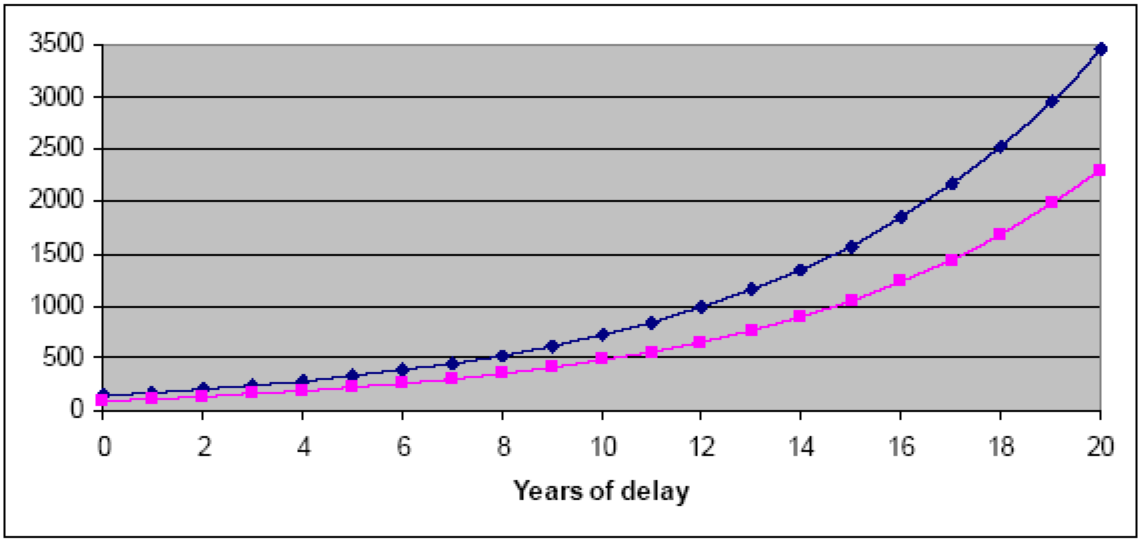
Figure 14. Specific cost of power plant equipment vs. resource temperature
Source: Hance, *Factors Affecting Costs of Geothermal Power Development*.

The temperature of the resource is an essential parameter influencing the cost of the power plant equipment. Each power plant is designed to optimize the use of the heat supplied by the geothermal fluid. The size and thus cost of various components (e.g., heat exchangers) are determined by the resource's temperature. As the temperature of the resource goes up, the efficiency of the power system increases, and the specific cost of equipment decreases (more energy being produced with similar equipment). Since binary systems use lower resource operating temperatures than flash steam systems, binary costs can be expected to be higher.

Figure 15 gives estimates for cost variance due to resource temperature.

The following table and chart shows the evolution of the expected value of a $100 and $150 capital investment when a 17% rate of return is considered. This illustrates the financial impact delays may have on the project viability.

Delay (years)	0	1	2	3	4	5	6	7	8	9	10
Exploration Costs	100	117	137	160	187	219	257	300	351	411	481
	150	176	205	240	281	329	385	450	527	616	721



Delay (years)	11	12	13	14	15	16	17	18	19	20
Exploration Costs	562	658	770	901	1054	1233	1443	1688	1975	2311
	844	987	1155	1351	1581	1850	2164	2532	2962	3466

Figure 15. Financial impact of delay on exploration costs
Source: Hance, *Factors Affecting Costs of Geothermal Power Development.*

Economies of scale might significantly decrease the specific cost of some components. One source (Hance 2005) gives an estimation for capital costs of geothermal projects with capacity ranges of 5 to 150 MW declining exponentially with their capacity according to the following relationship: **CC = 2500e^-0.0025(P-5)**, where CC represents capital costs and P the project's power capacity as shown in Figure 16.

Capacity	Capital Cost
5	2500
20	2411
34	2325
49	2242
63	2163
78	2086
92	2011
107	1940
121	1871
136	1804
150	1740

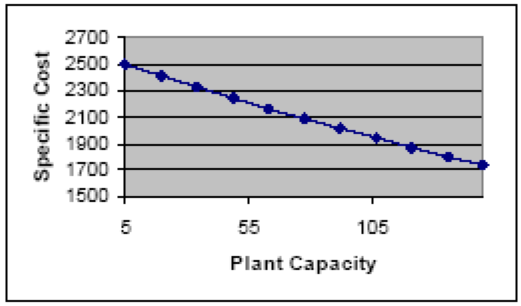


Figure 16. Economies of scale

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

Current Costs

Several sources provide estimated costs for geothermal development. Based on an analysis of the cost drivers given above, it is difficult to use general average costs without examining specific potential project sites.

In July 2002, the Energy Commission executed a PIER contract with the Hetch Hetchy Water and Power Division of the San Francisco Public Utilities Commission (Hetch Hetchy/SFPUC) to fund studies and projects relating to renewable energy. GeothermEx, Inc. (GeothermEx) was retained by Hetch Hetchy/SFPUC to provide a geothermal resource assessment for California and western Nevada. This section summarizes the findings of GeothermEx on the resource assessment for California.

GeothermEx used prior research, exploration, and development results available in the public domain. It also used data and information released by some developers into the public domain for this study. Three baseline conditions were used to determine the geothermal resource areas included in this assessment: geographic location, resource temperature, and evidence of a discrete resource. In California, 22 geothermal resource areas were included in the assessment.

Among the various geothermal resource areas, the amount and quality of technical data are extremely variable. A uniform set of required resource criteria therefore needed to be quantified to determine commercial feasibility for each resource area. For each selected reservoir values for the following criteria were obtained or reasonably estimated: temperature, area, thickness, porosity, and resource recovery factor.

To better capture the uncertainty of each resource, the minimum, most likely and maximum values, were used for each criterion. These values were then used in probabilistic simulation, (based on Monte Carlo random-number sampling,) to calculate estimated generation capacity based on accessible heat at the resource area. Because the generation capacity is estimated based on calculated heat in place, there is no guarantee that sufficient permeability exists to allow commercial production for those resources where little or no test drilling has occurred.

A summary of this analysis, with development costs for specific sites suitable for binary plant development, is shown in Table 12.[54]

Table 12. Potential binary geothermal plant development in California (most likely sources)

Geothermal Resource Area	County	Resource Type	Potential Development (MW)	Estimated Cost ($2004/kW)	Estimated Cost ($2009/kW)
Dunes	Imperial	Binary	11	$4,085	$4,726
East Mesa	Imperial	Binary	74.8	$5,141	$5,948
Glamis	Imperial	Binary	6.4	$4,953	$5,731
Heber	Imperial	Binary	42	$2,706	$3,131
Mount signal	Imperial	Binary	19	$2,746	$3,177
Superstition Mountain	Imperial	Binary	9.5	$3,211	$3,715
Honey Lake (Wendel-Amedee)	Lassen	Binary	1.9	$2,484	$2,874
Long Valley (Mono- Long Valley) Mammoth Pacific Plants	Mono	Binary	71	$2,034	$2,353
Sespe Hot Springs	Ventura	Binary	5.3	$4,112	$4,758
Total			**241**		
High				**$5,141**	**$5,948**
Low				**$2,034**	**$2,353**
Average				**$3,497**	**$4,046**

Source: Sison-Lebrilla, Elaine and ValentinoTiangco, Geothermal Strategic Value Analysis

A straight average is used to estimate average costs. A weighted average would yield a difference of approximately 2%, which is considered small for the purposes of the cost modeling.

Another source (Kagel 2006) provides general cost data for geothermal plants but does not separate between binary or flash technologies. That source estimates $2,770/kW ($2004) as total development costs, which is 79% of the average costs derived for California resources in this study. Since binary plants are typically more expensive than flash geothermal plants, and since the values presented above are based on actual site evaluations, the 21% discrepancy is considered acceptable when evaluating corroborating sources for cost estimates.

Operation and maintenance costs can be separated into fixed ($/kW-yr) and variable ($/MWh-yr) costs. When considering variable costs, one must determine facility capacity factor. Actual installations in California and Nevada were used in estimating capacity factor.

54 Sison-Lebrilla, Elaine, Valentino Tiangco *Geothermal Strategic Value Analysis*. CEC-500-2005-105-SD, June 2005.

Table 13. California and Nevada existing binary plants with capacity factor[55]

Owner	Plant	Location	Type	Year	No. Of Units	Rating MW	Capacity Factor %	Annual Energy GWh
Wineagle Development	Wineagle	California	Binary	1985	2	0.7	80	5
TG/USEC	Amedee	California	Binary	1988	2	1.6	80	11
ORMAT	Mammoth/Pacific	California	Binary	1984	2	10	90	79
ORMAT	ORMESA IE	California	Binary	1988	10	10	90	79
ORMAT	ORMESA IH	California	Binary	1989	12	12	90	95
ORMAT	ORMESA I	California	Binary	1987	26	20	90	158
ORMAT	ORMESA II	California	Binary	1988	20	20	90	158
ORMAT	Mammoth/Pacific	California	Binary	1990	3	30	90	236
ORMAT	Second Imperial Project	California	Binary	1993	12	33	80	231
ORMAT	GEM 1	California	Binary	1979	1	Retired		
SDG&E	Binary Demo.	California	Binary	1985	1	Retired		
Empire Energy	Empire	Nevada	Binary	1987	4	4.8	90	38
Constellation	Soda Lake 1	Nevada	Binary	1987	3	26.1	90	206
ORMAT	Steamboat I	Nevada	Binary	1986	7	10.8	95	90
ORMAT	Steamboat 2	Nevada	Binary	1992	2	47.8	95	398
OESI/CON	SWI	Nevada	Binary	1989	14	21	90	166
Home Stretch Geothermal	Wabuska I	Nevada	Binary	1984	1	2.2	90	17

Source: Oregon Institute of Technology: http://geoheat.oit.edu/directuse/power.htm

Actual capacity factors range from 80% to 95% with most being at 90%.

Another thing to note about the existing installations is the number of generation units for each site. From the data, plant sizes range from 0.7 to 47.8 MW. Nearly every plant uses multiple generators, with generator sizes ranging in size from 0.35 to 10 MW.

Based on an evaluation of the actual installations given in Table 13, a general range of plant sizes is as follows:

Average:	15 MW
High:	50 MW
Low:	2 MW

These values are used for the cost modeling.

55 Source: Oregon Institute of Technology: http://geoheat.oit.edu/directuse/power.htm.

O&M values for binary geothermal were determined with the values given in \$2004/kW-yr.[56] Those applicable to variable O&M were then converted to \$/MWh based on high, low, and average capacity factors using 9.

Equation 1: Conversion Factor to Variable O&M

$$\$/\text{MWh} = \$/\text{kW-yr} / 8.76 / \text{Capacity Factor}$$

All values were adjusted from \$2004 to \$2009 in proportion to inflation. The results of the analysis are included in Table 14.

Table 14. Fixed and variable O&M for binary geothermal power plants

Binary Geothermal O&M	Cost (\$2004 / kw-yr)	Fixed O&M (\$2009 / kW-yr)	Average Capacity Factor	Variable O&M (\$2009 / MWh)	High Capacity Factor	Variable O&M (\$2009 / MWh)	Low Capacity Factor	Variable O&M (\$2009 / MWh)
Field, General O&M and Rework	\$24		0.9	\$3.52	0.95	\$3.34	0.8	\$3.96
Makeup Wells	\$6		0.9	\$0.88	0.95	\$0.83	0.8	\$0.99
Relocation Injection Wells	\$1		0.9	\$0.15	0.95	\$0.14	0.8	\$0.17
Power Plant O&M	\$41	\$47.44						
Total	**\$72**	**\$47.44**		**\$4.55**		**\$4.31**		**\$5.12**

Source: KEMA

There is also some variability in fixed O&M. The referenced report provides only average values. In general, values vary approximately ±15%,[57] which is used to estimate high and low fixed O&M values.

Fixed O&M Average: \$47.44

Fixed O&M High: \$54.56

Fixed O&M Low: \$40.32

Expected Cost Trajectories

Binary geothermal power is a very mature technology with a limited number of sites available for generation. While the technology could have a learning effect of up to 20%, implying that for a doubling of installed capacity costs would be reduced by 20%, the small number of sites available for development makes it difficult to obtain those learning effects. Based on cumulative geothermal installed generation in 2009 at 2.4 GW to 2029 expected capacity of 3 GW, the research team expects a learning effect of no more than 7% over that period.

While completing the interim project report, the research team was provided with earlier research on geothermal cost trajectories that potentially conflicts with the assessment of the

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56 Sison-Lebrilla, Elaine, Valentino Tiangco. *Geothermal Strategic Value Analysis*. CEC-500-2005-105-SD, June 2005.

57 Lovekin, James, Subir Sanyal, Adil C. Sener, Valentino Tiangco, and Pablo Gutierrez-Santana. "Potential Improvements to Existing Geothermal Facilities in California." *GRC Transactions* 30, 2006.

learning effects for geothermal.[58] The premise of this research is that given enough R&D investment, geothermal projects can become cost equivalent to, or better than, similar-sized fossil-fueled projects. The authors cite in their research an S-curve technology experience model that is essentially similar to other logarithmic-based experience curve models, including the basic premises that the research team used in the computation of long-run cost trajectories for cost of generation data.

Schilling and Esmundo cite in their research the fact that geothermal costs have steadily declined since 1980, from 13.8 cents/kWh to 2005 values of 4.3 cents/kWh. Their fundamental conclusion regarding geothermal cost trajectories is that with a R&D investment of approximately $7.5 billion, geothermal energy should become more cost-competitive than the fossil-fuel price of energy.

The research team evaluated the Schilling and Esmundo conclusion regarding geothermal technology cost trajectory. First, the research team notes that Schilling and Esmundo cite in their paper that "Geothermal's key disadvantage is that given the state of technology, it is currently very geographically constrained with only limited areas enabling cost-efficient use of geothermal energy." The primary drivers in experience curve cost trajectory effects are the learning rates involved in a technology and the cumulative investment (installed capacity) over time. If one cannot obtain sufficient growth expansions in cumulative capacity, then experience curve cost trajectories are moderated and overall cost trajectories flattened.

The research team used the cumulative capacity addition estimates provided by the DOE for geothermal technologies, the same data used by the research team to estimate the cost trajectory effects for all technology types. This dataset shows a geothermal current cumulative installed base of 2.4 GW in 2009, and rising to 3.0 GW in 2030, or a year-over-year average growth rate of 1.07% per year.

Next, taking the premise from Schilling and Esmundo of an incremental R&D investment of $7.5 billion dollars, assuming that R&D goes into capacity additions at the average installed plant cost of $4.6 million per MW installed generation, the research team calculated the amount of cumulative generation as 16,300 MW to be required to reach the fossil-fuel equivalency projected by Schilling and Esmundo. That 16 GW calculated requirement is more than five times the projected increase in cumulative installed base projected by DOE.

The research team concludes that while this research provided has valuable insights, the fundamental issues regarding geothermal power development remain as they stated in their own research – that the availability of suitable sites ultimately provides a constraint in the amount of cumulative installed capacity that can be installed in a reasonable timeframe. Also noted is that the cost trajectory improvements foreseen in this cost of generation study, on the order of 10% over the study period through 2030, correspond well to DOE's own estimates,

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58 Schilling, Melissa A. and Melissa Esmundo. "Technology S-Curves in Renewable Energy Alternatives: Analysis and Implications for Industry and Government." *Energy Policy*(2009), doi:10.1016/j.enpol.2009.01.004 .

which project a 10% cost improvement through 2025. The research team's judgment is that geothermal energy development is a relatively mature technology, and we anticipate reasonable learning effects, but not those that would enable fossil fuel cost parity, over the study duration.

3.3.3. Geothermal – Flash

Technical and Market Justification

Current California flash geothermal installations total 700 MW.[59] An additional 2,220 MW potential development is likely using flash technology.[60]

Primary Commercial Embodiment

Flash steam plants pull deep, high-pressure hot water into lower-pressure tanks and use the resulting flashed steam to drive turbines. This is the most common type of plant in operation today. Most California plants use one generator, but some use two or three. Total plant capacities range from 10 to 52 MW, with most at approximately 30 MW.

The typical flash geothermal power plant in 2018 is foreseen to be similar in function and size to the current installations.

Cost Drivers

Much of the information on cost drivers is common to both binary and flash geothermal plants. Common information between the two technologies that is given in the binary section is not repeated in this section.

Market and Industry Changes

There have been no market and industry changes since August 2007 that have materially affected flash geothermal technologies.

Current Trends

Flash geothermal is a mature technology with a limited number of sites in California suitable for its development. The primary cost driver is development of the site. Should these sites be developed, the less expensive sites (greatest return on investment) would be first, with the more expensive sites to follow. Any learning curve in development would most likely be a cost avoidance rather than a cost saving. Therefore any cost reduction trends are unlikely to be seen.

Cost Drivers

In addition to the cost drivers listed in the binary section, for some flash plants, a corrosive geothermal fluid may require the use of resistive pipes and cement. Adding a titanium liner to protect the casing may significantly increase the cost of the well. This kind of requirement is rare, and in the United States, limited to the Salton Sea resource (Hance 2005).

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59 Source: http://geoheat.oit.edu/directuse/power.htm

60 Sison-Lebrilla, Elaine, Valentino Tiangco. *Geothermal Strategic Value Analysis*. CEC-500-2005-105-SD, June 2005.

Current Costs

The source documentation and methods for estimating current costs of flash geothermal plants are included in the binary section. The results specific to flash technologies are given below.

A summary of the resource analysis, with development costs, for specific sites suitable for flash plant development, is shown in Table 15.[61]

Table 15. Potential flash geothermal plant development in California (most likely sources)

Geothermal Resource Area	County	Resource Type	Potential Development (MW)	Estimated Cost ($2004/kW)	Estimated Cost ($2009/kW)
Salton Sea (including Westmoreland) - Low	Imperial	Flash	1400	$2,250*	$2,603
Salton Sea (including Westmoreland) - High	Imperial	Flash	1400	$4,500*	$5,207
Brawley (North)	Imperial	Flash	135	$2,638	$3,052
Brawley (East)	Imperial	Flash	129	$4,195	$4,854
Brawley (South)	Imperial	Flash	62	$4,606	$5,329
Niland	Imperial	Flash	76	$3,249	$3,759
Coso Hot Springs	Inyo	Flash	55	$3,405	$3,940
Sulfur Bank Field, Clear Lake Area	Lake	Flash	43	$2,347	$2,715
Calistoga	Napa	Flash	25	$3,403	$3,937
Lake City/Surprise Valley	Modoc	Flash	37	$3,146	$3,640
Randsburg	San Bernardino/ Kern	Flash	48	$2,615	$3,026
Medicine Lake (Fourmile Hill)	Siskiyou	Flash	36	$2,674	$3,094
Medicine Lake (Telephone Flat)	Siskiyou	Flash	175	$2,275	$2,632
Total			**2221**		
High			**175**	**$4,606**	**$5,329**
Low			**25**	**$2,250**	**$2,603**
Average			**75**	**$3,177**	**$3,676**

* The Salton Sea resource includes high and low cost estimates.

Source: Sison-Lebrilla, Elaine and Valentino Tiangco. Geothermal Strategic Value Analysis.

Another source (Kagel 2006) provides general cost data for geothermal plants but does not separate between binary or flash technologies. That source estimates $2,770/kW ($2004) as total development costs, which is 88% of the costs recommended in this study. Since the values

61 Sison-Lebrilla, Elaine, Valentino Tiangco. *Geothermal Strategic Value Analysis*. CEC-500-2005-105-SD, June 2005.

presented above are based on actual site evaluations, the 12% discrepancy is considered acceptable when evaluating corroborating sources for cost estimates.

O&M costs can be separated into fixed ($/kW-yr) and variable ($/MWh-yr) costs. When considering variable costs, one must determine facility capacity factor. Existing installations in California and Nevada were used in estimating capacity factor.

Table 16. California and Nevada existing flash plants with capacity factor[62]

Owner	Plant	Location	Type	Year	No. Of Units	Rating MW	Capacity Factor %	Annual Energy GWh
ORMAT	GEM 3	California	Double Flash	1989	1	18.5	92.5	146
ORMAT	Dual-Flash	California	Double Flash	1985	1	52	90	410
CalEnergy	J.M. Leathers	California	Double Flash	2000	1	10	104	91
ORMAT	GEM 2	California	Double Flash	1989	1	18.5	92.5	146
CalEnergy	S. S. 2	California	Double Flash	1990	3	20	104	182
CECI	Navy 1: Unit 2	California	Double Flash	1988	1	30	116	305
CECI	Navy 1: Unit 3	California	Double Flash	1988	1	30	116	305
CECI	Navy 2: Unit 4	California	Double Flash	1989	1	30	116	305
CECI	Navy 2: Unit 5	California	Double Flash	1989	1	30	116	305
CECI	Navy 2: Unit 6	California	Double Flash	1989	1	30	116	305
CECI	BLM 1: Unit 7	California	Double Flash	1988	1	30	116	305
CECI	BLM 1: Unit 8	California	Double Flash	1988	1	30	116	305
CECI	BLM 1: Unit 9	California	Double Flash	1989	1	30	116	305
CECI	Navy 1: Unit 1	California	Double Flash	1987	1	34	116	345
CalEnergy	Vulcan	California	Double Flash	1985	2	38	104	346
CalEnergy	J.J. Elmore	California	Double Flash	1989	1	38	104	346
CalEnergy	J.M. Leathers	California	Double Flash	1989	1	38	104	346
CalEnergy	S. S. 4	California	Double Flash	1996	1	40	104	403
Calenergy	A.W. Hoch (Del Ranch)	California	Double Flash	1989	1	42	104	383
CalEnergy	S. S. 3	California	Double Flash	1989	1	50	104	455
CalEnergy	S. S. 5	California	Double Flash	2000	1	50	104	503
CalEnergy	S. S. 1	California	Single Flash	1982	1	10	104	91
Caithness	Beowawe	Nevada	Double Flash	1985	1	16.6	90	131
ORMAT	Brady Hot Springs	Nevada	Double Flash	1992	3	21.1	98	181
ORMAT	Desert Peak	Nevada	Double Flash	1985	2	12.5	98	107
Caithness	Dixie Valley	Nevada	Double Flash	1988	1	62	90	489
ORMAT	Steamboat Hills	Nevada	Single Flash	1988	1	14.4	95	120

Source: http://geoheat.oit.edu/directuse/power.htm

62 Source: http://geoheat.oit.edu/directuse/power.htm

Actual capacity factors in California range from 90% to 116% and in Nevada range from 90% to 98%. For the purposes of cost modeling, it's unreasonable to assume capacity factors at or above unity. A range of 90% to 98% was selected with the average being 94%.

Another thing to note is that most flash geothermal plants use a single generator. Plant capacities range from 10 to 62 MW. Generator capacities range from 7 to 62 MW.

Based on an evaluation of the actual installations given in Table 16, a general range of plant sizes is as follows:

Average:	30 MW
High:	50 MW
Low:	7 MW

These values are used for the cost modeling.

O&M values for flash geothermal were determined with the values given in $2004/kW-yr.[63] Those applicable to variable O&M were then converted to $/MWh based on high, low and average capacity factors using Equation 2.

Equation 2: Conversion Factor to Variable O&M

$$\$/\text{MWh} = \$/\text{kW-yr} / 8.76 / \text{Capacity Factor}$$

All values were adjusted from $2004 to $2009 in proportion to inflation. The results of the analysis are included in Table 17.

Table 17. Fixed and variable O&M for flash geothermal power plants

Flash Geothermal O&M	Cost ($2004 / kw-yr)	Fixed O&M ($2009 / kW-yr)	Average Capacity Factor	Variable O&M ($2009 / MWh)	High Capacity Factor	Variable O&M ($2009 / MWh)	Low Capacity Factor	Variable O&M ($2009 / MWh)
Field, General O&M and Rework	$27		0.94	$3.79	0.98	$3.64	0.9	$3.96
Makeup Wells	$7		0.94	$0.98	0.98	$0.94	0.9	$1.03
Relocation Injection Wells	$2		0.94	$0.28	0.98	$0.27	0.9	$0.29
Power Plant O&M	$47	$54.38						
Total	**$83**	**$54.38**		**$5.06**		**$4.85**		**$5.28**

Source: KEMA

63 Sison-Lebrilla, Elaine, Valentino Tiangco. *Geothermal Strategic Value Analysis*. CEC-500-2005-105-SD, June 2005.

There is also some variability in fixed O&M. The referenced report provides only average values. In general, values vary approximately ±15%,[64] which is used to estimate high and low fixed O&M values.

Fixed O&M Average:	$58.38
Fixed O&M High:	$67.14
Fixed O&M Low:	$49.62

Expected Cost Trajectories

See the Binary Geothermal section for an analysis of expected cost trajectories.

Flash Geothermal Emissions

Unlike many renewable technologies, flash geothermal plants produce emissions. A listing of emissions is provided below (units are in lbs/MWh):[65,66]

- CO: 0.058
- NOx: 0.191
- SO2: 0.026
- VOC: 0.011
- H2S: 0.092
- CO_2: 60

3.4. Hydropower

3.4.1. Technology Overview

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine depends on the head (vertical height the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such applications allow for

64 Lovekin, James, Subir Sanyal, Adil C. Sener, Valentino Tiangco, and Pablo Gutierrez-Santana. "Potential Improvements to Existing Geothermal Facilities in California." *GRC Transactions* 30, 2006.

65 Sison-Lebrilla, Elaine, Valentino Tiangco. *Geothermal Strategic Value Analysis*. CEC-500-2005-105-SD, June 2005.

66 Singleton, Will, *Western Governors' Association, Clean and Diversified Energy Initiative, Geothermal Task Force Report*. January 2006.

hydroelectric generation without the impact of damming the waterway. There are three main types of hydropower facilities:

- Impoundment hydropower uses a dam to store water in a reservoir. Water can be released from the reservoir to generate electricity.
- Run-of-river uses the flow of water within a river, requiring very little or no impoundment. Run-of-river hydropower is typically designed for large flows with low head or small flows with high head.
- Diversion hydropower diverts a portion of river flows through a canal or penstock to generate electricity.

See tables for illustrations of the various types of hydropower facilities.

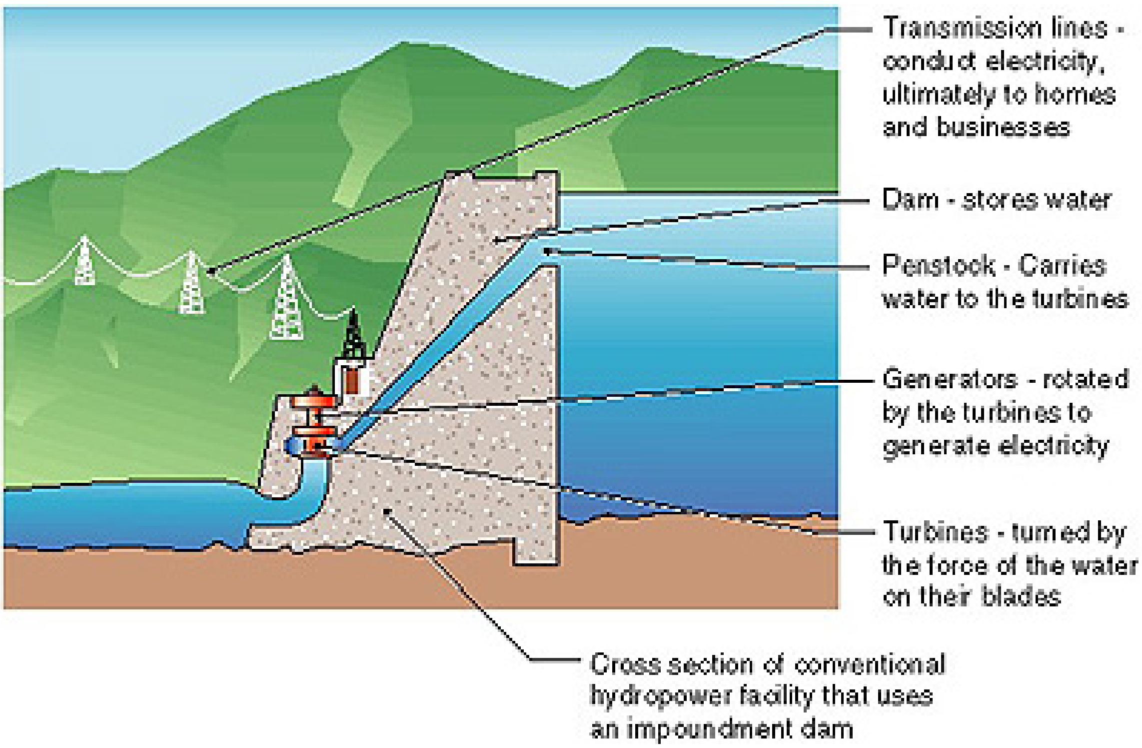

Figure 17. Impoundment hydropower

Source: U.S. DOE, EERE

Figure 18. Diversion hydropower facility

The Tazimina project in Alaska is an example of a diversion hydropower plant. No dam was required.

Source: U.S. DOE, EERE

Figure 19. Run-of-river hydropower facility

Chief Joseph Dam near Bridgeport, Washington, is a major run-of-river station without a sizeable reservoir.

Photo Credit: Wikipedia

Two categories were selected for this study as defined below:

- Hydro – Developed sites without power: There are many sites in California with dams or with diversion systems in place, but without hydroelectric power. This category focuses on the potential hydroelectric potential of these sites.
- Hydro – Capacity upgrade for developed sites with power: Some existing hydroelectric facilities in California and the surrounding states are developed with power generation in place but with potential to increase generation output. This can be accomplished through increasing reservoir size, upgrading total turbine capacity, increasing the number of turbines, or any combination thereof.

3.4.2. Hydro – Developed Sites Without Power

Technical and Market Justification

Hydroelectric power is a well established technology. The United States hydroelectric plant population is composed of 2,388 licensed plants (not including pumped storage plants), according to the 1998 version Federal Energy Regulatory Commission's Hydroelectric Resource Assessment (HPRA) database (FERC 1998). These plants range in capacity from less than 100 kW to over 6,000 MW and have a total capacity of 74,872 MW. The plants are owned by 1,134 owners, including owners in the public and private sectors.[67]

Developed waterways without power in California include 274 sites with a total nameplate potential of 4,812 MW.[68] Capacity estimates range from 1.5 MW to 300 MW with the average being approximately 15 MW.

Primary Commercial Embodiment

Hydroelectric power is a major source of California's electricity. In 2007, hydroelectric power plants produced 43,625 gigawatt-hours (GWh) of electricity, or 14.5% of the total. Hydro facilities are broken down into two categories. Larger than 30 MW capacity are called *large* hydro. Smaller than 30 MW capacity is considered "small" hydro and are totaled into the renewable energy portfolio standards. The amount of hydroelectricity produced varies each year. It is largely dependent on rainfall (source: California Energy Commission).

California has nearly 400 hydro plants, which are mostly located in the eastern mountain ranges and have a total dependable capacity of about 14,000 MW of capacity. The state also imports hydro-generated electricity from the Pacific Northwest (source: California Energy Commission).

The number of hydroelectric plants in California is expected to increase by 2018. It is uncertain what the number of plants and total installed capacity will be.

Cost Drivers

Since hydroelectric is a very mature, well-established technology, there have been no industry changes since August of 2007 that have materially affected costs. Also no trends are foreseen that would materially affect future costs.

The primary cost drivers for this technology are as follows.[69]

Initial Costs:

- Licensing
- Construction
- Environmental mitigation
    - Fish and wildlife mitigation
    - Recreation mitigation

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67 Hall, Douglas G. and Kelly S. Reeves. *A Study of United States Hydroelectric Plan Ownership*. U.S. Department of Energy. Idaho National Laboratory. INL/EXT-06-11519, June 2006.

68 Conner, Alison M., Ben N. Rinehart, and James E. Francfort. *U.S. Hydropower Resource Assessment for California*. U.S. Department of Energy. Idaho National Laboratory. DOE/ID-10430(CA), October 1998.

69 Hall, Douglas G., Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll. *Estimation of Economic Parameters of U.S. Hydropower Resources.* U.S. Department of Energy. Idaho National Laboratory. Bechtel BWXT Idaho LLC and INL Hydropower Resource Economics Database, June 2003.

  - Historical and archeological mitigation
  - Water quality monitoring
  - Fish passage

The various types of environmental mitigation are site-specific (all are not required for each site).

Annual Costs

- Fixed O&M
  - Operation supervision and engineering
  - Maintenance supervision and engineering
  - Maintenance of structures
  - Maintenance of reservoirs, dams, and waterways
  - Maintenance of electric plant
  - Maintenance of miscellaneous hydraulic plant
- Variable O&M
  - Water for power
  - Hydraulic expenses
  - Electric expenses
  - Miscellaneous hydraulic power expenses
  - Rents
- FERC annual charge

Current Costs

Costs were developed through the Idaho National Laboratory (INL) Hydropower Resource Economics Database.[70] This database was developed from surveys of existing hydroelectric facilities. In developing this database, regression models were built relative to each cost driver and applied to potential sites throughout the United States. The database is presented in 2002 United States' dollars. These costs were converted to 2009 United States dollars for this study.

A manipulation of the data was required to convert the costs to the units necessary for use in the COG model. Only data for potential sites in California were used. With the database in the required units, relationships were developed between unit rated capacity and costs:

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70 http://hydropower.inel.gov/resourceassessment/index.shtml.

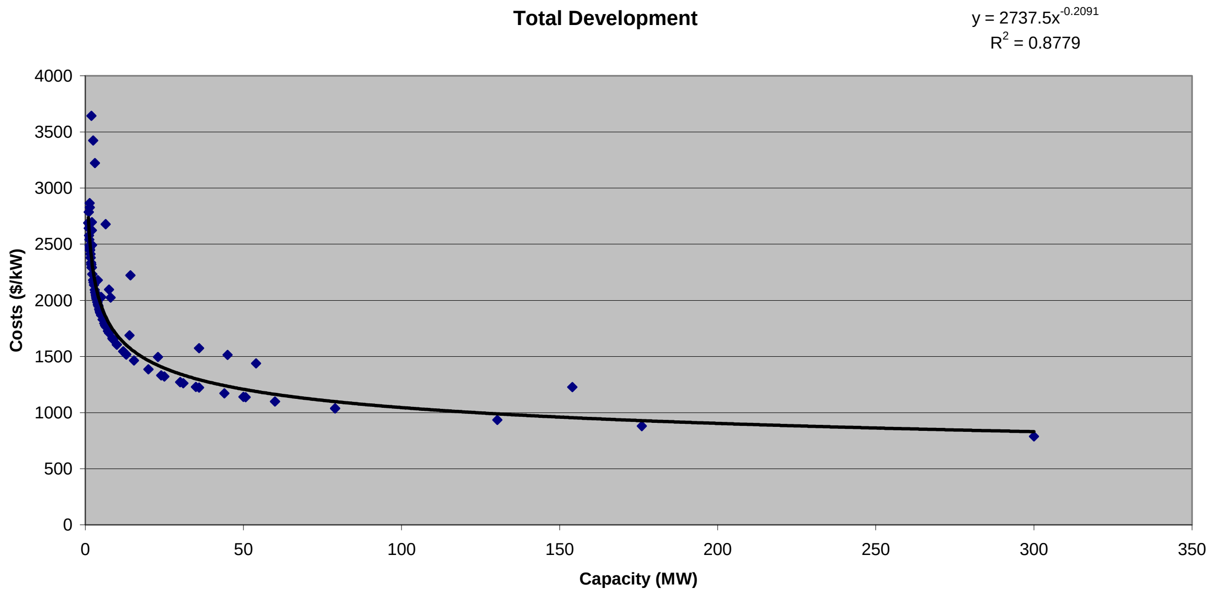

Figure 20. Hydropower costs for developed sites without power
Source: Idaho National Laboratory Hydropower Resource Economics Database

Figure 20 shows the relationship between unit capacity and cost with a curve fitting the data points 88% of the time, which is assumed acceptable for cost estimations. The data is provided in 2002 United States dollars, so the result must be converted to 2009 United States' dollars per inflation. Some cost data points are noticeably higher than others, which denote sites where a higher degree of mitigation is required. In addition to the overall cost curve, relationships were developed for other parameters, based on the data sets for California sites only, where X is the capacity of the plant in MW and Y is the total cost in $/kW or $/MWh as shown:

Equation 3: Total Development Costs ($/kW)

y = 2737.5x^-0.2091

Equation 4: Licensing Cost ($/kW)

y = 306.53x^-0.3027

Equation 5: Construction Cost ($/kW)

y = 2180x^-0.1928

Equation 6: Instant Cost ($/kW)

Instant Cost = Licensing Cost + Construction Cost

Equation 7: Installed Cost ($/kW)

Installed Cost = Total Development Cost (includes licensing, construction and average mitigation costs)

Equation 8: Fixed O&M Costs ($/kW)

y = 23.707x^-0.2469

Equation 9: Variable O&M Costs ($/MWh)

y = 4.9659x^-0.2024

The above equations were used to estimate costs based on installed capacity (x = capacity, y = cost) for each parameter.

- Overnight costs ($/kW):
  - Average: $1,882
  - High : $3,046
  - Low: $1,006
- Fixed O&M ($/kW-yr):
  - Average: $17.57
  - High: $28.83
  - Low: $9.88
- Variable O&M ($/MWh):
  - Average: $3.48
  - High: $5.54
  - Low: $1.90

Capacity factors can vary dramatically. The INL Resource Database lists average hydroelectric capacity factors for California to be 54.87%. When evaluating actual capacity factors for hydroelectric power plants in California, capacity factors were found to be much different. The evaluation was performed as follows:

- Actual output (MWh) for 2007 and nameplate ratings (MW) were obtained for all hydroelectric facilities in California from the Energy Information Administration (EIA).
- All units with a capacity below 1.5 MW were removed.
- All pumped storage facilities were removed.
- Capacity factors were calculated for all remaining sites.
- Some of the data was found to be in error with capacity factors at or below zero or above 100%. So all facilities with capacity factors reported showing below 10% and above 90% were removed (approximately 10% of the sites).

- From this data set, it was considered unrealistic to choose the extreme high and low values. A more realistic approach for modeling was to remove the top and bottom 5%. This resulted in 178 facilities remaining, which were used to estimate capacity factor.
    - Average: 30.4% (weighted average of all sites on the listing)
    - High: 61.5%
    - Low: 12.5%

Expected Cost Trajectories

Hydroelectric power is a very mature technology with a limited number of sites available for generation. Costs are not foreseen to decrease with increased generation projects and no learning effects were modeled. Cost trajectories were determined solely by projected inflation from 2009 to 2029.

3.4.3. Hydro – Capacity Upgrade for Developed Sites With Power

Technical and Market Justification

Developed waterways without power in California include 26 sites with a total nameplate potential of 1,744 MW.[71] Potential upgrades range in nameplate capacity from 2 MW to 600 MW with the average being approximately 80 MW.

Primary Commercial Embodiment

California's nearly 400 hydro plants, with a total dependable capacity of about 14,000 MW, are mostly located in the eastern mountain ranges. California state also imports hydro-generated electricity from the Pacific Northwest (source: California Energy Commission).

The number of hydroelectric plants in California is expected to increase by 2018. It is uncertain what the number of plants and total installed capacity will be.

Cost Drivers

Since hydroelectric is a very mature, well established technology, there have been no industry changes since August 2007 that have materially affected costs. Also no trends are foreseen that would materially affect future costs.

The primary cost drivers for this technology are as follows:[72]

Initial Costs:

- Licensing

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71 Conner, Alison M., Ben N. Rinehart, and James E. Francfort. *U.S. Hydropower Resource Assessment for California*. U.S. Department of Energy. Idaho National Laboratory. DOE/ID-10430(CA), October 1998.

72 Hall, Douglas G., Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll. *Estimation of Economic Parameters of U.S. Hydropower Resources*. U.S. Department of Energy. Idaho National Laboratory. Bechtel BWXT Idaho LLC and INL Hydropower Resource Economics Database, June 2003.

- Construction
- Environmental mitigation
- Fish and wildlife mitigation
- Recreation mitigation
- Historical and archeological mitigation
- Water quality monitoring
- Fish passage

The various types of environmental mitigation are site specific (all are not required for each site).

Annual Costs:

- Fixed O&M
- Operation supervision and engineering
- Maintenance supervision and engineering
- Maintenance of structures
- Maintenance of reservoirs, dams, and waterways
- Maintenance of electric plant
- Maintenance of miscellaneous hydraulic plant
- Variable O&M
- Water for power
- Hydraulic expenses
- Electric expenses
- Miscellaneous hydraulic power expenses
- Rents
- FERC annual charge

Current Costs

Costs were developed through the INL Hydropower Resource Economics Database. This database was developed from surveys of existing hydroelectric facilities. In developing this database, regression models were built relative to each cost driver and applied to potential sites throughout the United States. The costs were converted to 2009 United States' dollars for this study.

A manipulation of the data was required to convert the costs to the units necessary for use in the COG model. Only data for potential sites in California were used. With the database in the required units, relationships were developed between unit rated capacity and costs.

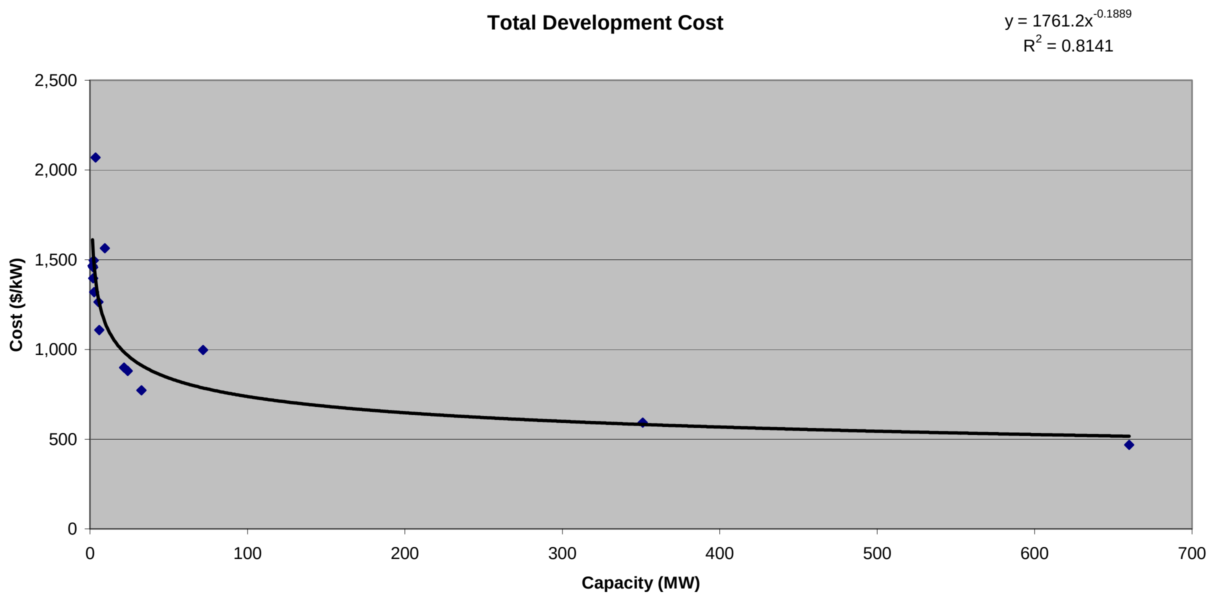

Figure 21. Hydropower costs for increasing capacity

Source: Idaho National Laboratory Hydropower Resource Economics Database

Figure 21 shows the relationship between unit capacity and cost with the data points fitting the curve 81% of the time, which is assumed acceptable for cost estimations. The data is provided in 2002 United States' dollars, so the result must be converted to 2009 United States' dollars per inflation. Some cost data points are noticeably higher than others, which denote sites where a higher degree of mitigation is required. In addition to the overall cost curve, relationships were developed for other parameters, based on the data sets for California sites only, where X is the Capacity of the plant in MW and Y is the total cost in $/kW or $/MWh as shown:

Equation 10: Total Development Costs ($/kW)

$$y = 1761.2x^{-0.1889}$$

Equation 11: Licensing Cost ($/kW)

$$y = 209.95x^{-0.3027}$$

Equation 12: Construction Cost ($/kW)

$$y = 1351.6x^{-0.1928}$$

Equation 13: Instant Cost ($/kW)

Instant Cost = Licensing Cost + Construction Cost

Equation 14: Installed Cost ($/kW)

Installed Cost = Total Development Cost (includes licensing, construction and average mitigation costs)

Equation 15: Fixed O&M Costs ($/kW)

$$y = 23.707x^{-0.2469}$$

Equation 16: Variable O&M Costs ($/MWh)

$$y = 4.7411x^{-0.1998}$$

The above equations were used to estimate costs based on installed capacity (x = capacity, y = cost) for each parameter.

- Overnight costs ($/kW):
  - Average: $932
  - High: $1,871
  - Low: $637
- Fixed O&M ($/kW-yr):
  - Average: $12.59
  - High: $27.05
  - Low: $8.77
- Variable O&M ($/MWh):
  - Average: $2.39
  - High: $5.00
  - Low: $1.60

The capacity factor average, high, and low are assumed to be the same as for hydro – developed sites without power.

Expected Cost Trajectories

Hydroelectric power is a very mature technology with a limited number of sites available for generation. Costs are not foreseen to decrease with increased generation projects and no learning effects were modeled. Cost trajectories were determined solely by projected inflation from 2009 to 2029.

3.5. Solar

3.5.1. Technology Overview

There are three types of solar electric generating technologies considered for cost modeling: solar parabolic trough (without energy storage), solar parabolic trough (with energy storage), and solar photovoltaic (Single Axis).

Solar Parabolic Trough – General:

This is also known as concentrating solar power (CSP) which uses mirrors to reflect and concentrate sunlight onto receivers that collect the solar energy and convert it to heat. This thermal energy can then be used to produce electricity via a steam turbine or heat engine driving a generator.

The predominant CSP systems in operation in the United States are linear concentrators using parabolic trough collectors. In such a system, the receiver tube is positioned along the focal line of each parabola-shaped reflector. The tube is fixed to the mirror structure, and the heated fluid–either a heat-transfer fluid or water/steam–flows through and out of the field of solar mirrors to where it is used to create steam (or, for the case of a water/steam receiver, it is sent directly to the turbine), shown in Figure 22.

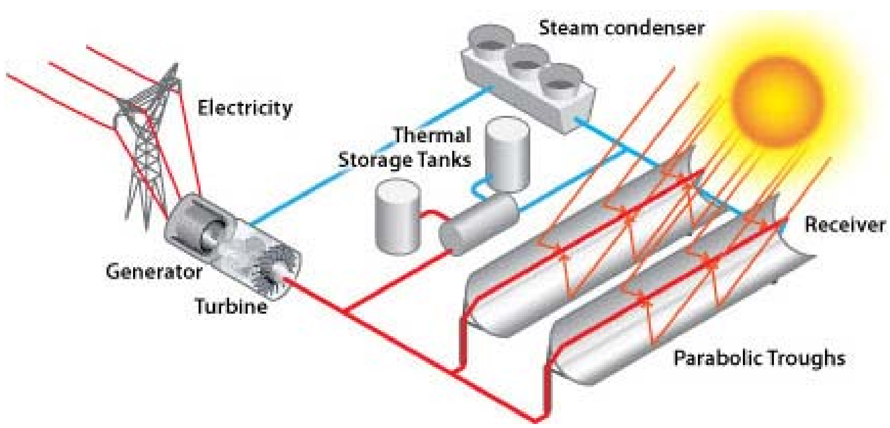

Figure 22. Solar parabolic trough electric generating system
Source: U.S. DOE, EERE

Solar Parabolic Trough – Energy Storage Technology Considerations:

The use of thermal energy storage technology enables the wider use of solar renewable energy as dispatchable power and provides grid flexibility for peak demand times. Currently, there are three commercialized technologies available for storing thermal energy from solar parabolic and power tower plants[73]:

73 Konrad, Tom. "IN DEPTH: Hot Debate over Thermal Storage." *CSP Today*, April 20, 2009.

- Steam – The least suitable method for thermal energy storage, as it lends itself to only short-term buffer storage, and used primarily to address short-term transient needs such as intermittent cloud cover.
- Mineral oil and synthetic heat transfer fluids – An approach currently used with existing technology solar parabolic trough systems, as the fluid does not solidify at night as molten salt systems can (at temperatures below 221 deg. C). Mineral oil systems are approximately three times more expensive to operate than molten salt systems, due to the oil cost, and so are chiefly used for shorter term duration storage of 30-60 minutes.
- Molten salt – Typical molten salt systems use a mixture of sodium nitrate and potassium nitrate (60% sodium nitrate – 40% potassium nitrate) heated above the melting point of 221 deg. C. Molten salt systems are currently used in power tower designs, and are being examined for implementation in parabolic trough systems. The cost of molten salt storage for a parabolic trough system, which is estimated at $90-160/kW, is roughly three times the cost of storage for a power tower system, due to the amount of molten salt needed, wider field arrays and transport distances for the trough system.

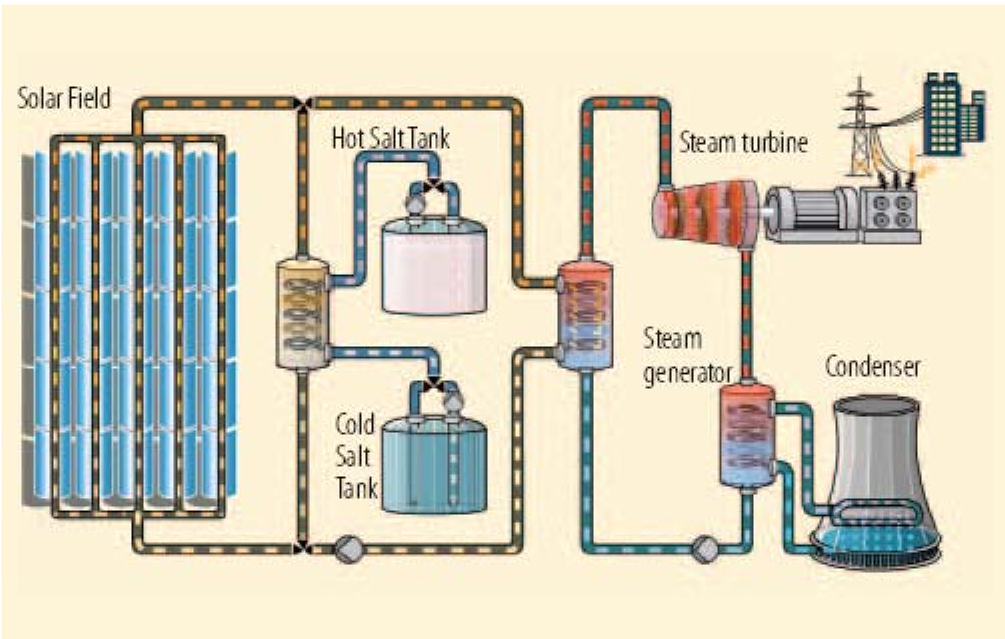

Figure 23. Simplified molten salt storage process diagram

Source: *Concentrating Solar Power – From Research to Implementation*, European Commission, 2007

The research team chose a molten salt thermal storage system for the best commercial embodiment of this storage technology because of the engineering and technical aspects of the molten salt approach. The molten salt storage technology currently in operation in Spain's AndaSol project was first successfully demonstrated in a test loop at the parabolic trough system operating in Kramer Junction, California. The AndaSol project provides 50 MW of generation capacity, with a molten salt storage system of 7.5 hours duration.[74]

For purposes of analysis, a molten salt storage system comprising six hours duration of energy storage was modeled and costed into the thermal storage case.

Solar Photovoltaic (Single Axis):

Photovoltaic (PV) systems include the PV modules themselves and the balance of systems (BOS). The BOS includes mounting structures, wiring, overcurrent protection, and inverters (the electronic device that converts DC to AC electricity). The mounting structures can include *trackers* that follow the sun's path throughout the day. A single-axis tracker simply tilts from east to west, following the sun's path throughout the day. An example of a single-axis PV system is the 14.2 MW facility at Nellis Air Force Base (Figure 24).

Figure 24. Nellis Air Force Base PV installation
Source: SunPower Corporation

3.5.2. Solar – Parabolic Trough

Technical and Market Justification

The research team selected parabolic trough technology because it is commercially available. CSP installations are producing electricity with a capacity of 354 MW since 1990 (source: NREL). With AndaSol 1 -3 one parabolic trough system with 50 MW is commercially running in Spain, and two additional 50 MW plants are under construction. Storage technology (molten salt) for seven full load hours is included in the AndaSol project. Storage or combined operation

74 "Concentrating Solar Power – From Research to Implementation." European Commission, 2007.

with gas leads to extended operation hours per day. Additional projects in Greece and Spain are being planned.

Primary Commercial Embodiment

California has nine parabolic trough CSP facilities in operation. They are all in the Mojave Desert and were built between 1985 and 1991. One is rated at 13.8 MW, six at 30 MW, and two at 80 MW. The reason for these sizes is the 13.8 MW plant was the first one built as a demonstration, the 30 MW plants were sized per PURPA restrictions in place at the time, and the 80 MW plants were built when PURPA restrictions were raised to 80 MW plants in 1989. There are currently no such PURPA restrictions in place for plant size (source: EIA).

In these plants, solar trough technology is used to produce steam in a conventional steam turbine generator. Natural gas was used as a supplementary fuel for up to 25% of the heat input.

In 2018, the research team expects that the primary commercial embodiment will tend toward larger systems. The current primary worldwide commercial embodiment today is in Spain, where feed-in tariffs have encouraged solar development, but system sizes are less than 50 MW due to restrictions in the feed-in tariff system. Solar Millennium has announced a 250 MW parabolic trough power station in Nevada.[75] An engineer at Solar Millennium told the research team that the system will consist of one 250 MW steam turbine (not 50 MW modules).

According to the engineer at Solar Millennium, the company believes 250 MW and expects to be the optimal size for parabolic trough systems and expects future systems to range from 200 to 300 MW. For smaller systems the turbine is too small (and therefore too expensive), and for bigger systems the losses in the solar collector field would be too high.

Cost Drivers

Market and Industry Changes

Spain has one of the most favorable feed-in tariffs for CSP plants paying at least United States' $0.39 per kWh. That is one reason why at the end of 2007 more than 50 CSP projects with about 2,150 MW have been registered by Spain's Ministry of Industry, making Spain the leading country in CSP development worldwide.

The first power station AndaSol 1 (50 MW) was commissioned in November 2008. AndaSol 2 (50 MW) is under construction, and AndaSol 3 (50 MW) will follow in 2009. All plants are equipped with six hours of molten salt storage. Due to the restrictions of the feed-in tariff law in Spain the capacity of the units is limited to 50 MW at maximum.

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75 Solar Millenium. *Nevada Energy, Solar Millennium and MAN Ferrostaal Cooperate in the Development of Projects*. Solar Millenium Corporate News, April 3, 2009.
http://www.solarmillennium.de/Press/Press_Releases/Nevada_Energy__Solar_Millennium_and_MAN_Ferrostaal_cooperate_in_the_development_of_projects,lang2,50,1532.html.

Current Trends

For 2009, the Spanish government has announced a change in the feed-in tariff. This will reduce the amount of new registered projects in Spain. Nevada Energy, Solar Millenium, and MAN Ferrostaal have announced a solar thermal power plant with a capacity of 250 MW and thermal storage capacity. Abengoa Solar has signed an agreement with Arizona Public Service (APS) to build and operate what will be the largest solar power plant in the world. The plant will be installed about 100 kilometers southwest of Phoenix, near Gila Bend. Solana, with 280 MWe of power output capacity, is based on parabolic trough technology and thermal storage using molten salts. It uses a single steam turbine.

Cost Drivers

The primary general cost drivers for parabolic trough systems are:

- Site work infrastructure.
- Solar field – Mirrors and solar receivers are the cost drivers of the system. Assumptions: Mass production of both elements could reduce costs.
- Steel price – Steel doubled in price between January 2008 and September 2008 and again between September 2008 and January 2009.
- Heat transfer fluid system.
- Thermal energy storage – Including thermal storage causes increases in cost due to the addition of the thermal energy storage system and additional solar field area required to charge the thermal storage system.
- Power block – Optimum size could reduce price of turbine and generator.
- Balance of systems.
- Contingency.
- Indirect costs.

Current Costs

From the three basic studies the following actual cost data were extracted:

Table 18. Parabolic trough cost comparison

	CEG-Study 2007 Navigant $	 €	NREL-Study 2006 Black & Veatch $	 €	RETI 2008 Black & Veatch $	 €
Gross Plant Capacity (kW)	63,500					
Net Plant Capacity (kW)	50,000		100,000		200,000	
Annual Degradation (%/y)	0.2%					
Project lifetime (y)	30					
Overnight Cost ($/kW)	3,900	3,120	4,944	3,955	3,900	3,120
Site Work & Infrastructure	39	31	25	20		
Solar Field	1,755	1,404	2,309	1,847		
Heat Transfer Fluid System	78	62	100	80		
Thermal Energy Storage (6 hrs.)	507	406	580	464		
Power Block	312	250	388	310		
Balance of Plant	195	156	225	180		
Contingency	234	187	307	246		
Indirect Costs	780	624	1,011	809		
Fixed O&M ($/kW/y)	60	48	67	54	66	53
Variable O&M ($/MWh)						
Development Time (months)	20		20		20	
Construction time	12		12		12	
Forced Outage Rate (%)	6%		6%		6%	
Typical Net Capacity Factor (%)	27%		27%		27%	

Source: CEG-Study: Klein and Rednam. *Comparative Costs of California Central Station Electricity Generation Technologies*. NREL-Study: Stoddard, Abrecunus, and O'Connell. *Economic, Energy, and Environmental Benefits*… RETI: Black & Veatch. *Renewable Energy Transmission Initiative Phase 1A.*

There are no actual published cost data available for the installations in Spain. In a publication downloaded from the homepage of Solar Millennium a number of 300 million euro (€) is mentioned. This would lead to specific costs of 7,500 $/kW.

From the same homepage a press release concerning the cooperation of Nevada Energy, Solar Millennium, and MAN Ferrostaal a CSP station with a capacity of 250 MW is announced with an investment volume of over 1 billion United States' dollars. This would lead to investment costs of over 4,000 $/kW.[76]

Press releases concerning the 64 MW ACCIONA CSP project in the Nevada desert report investment costs between 220 million and 266 million United States' dollars. This would lead to specific investment costs of 3,438 and 4,156 $/kW.[77]

Technology assumptions: 520,000 m² parabolic trough solar field (SKAL-ET), cases include both non-storage systems, a 6-hour reserve molten-salt thermal storage system, and a 250 MW-capacity steam cycle. The technology case that includes six-hour molten-salt thermal storage also accounts for a 57% solar field area increase, used to charge the storage system and to improve capacity factor.[78]

Expected Cost Trajectories

The direct costs of a parabolic solar plant can be summarized into the following five major categories:

- Siteworks and infrastructure
- Solar field
    - Heat Collection Element (HCE)
    - Mirror
    - Support structure
    - Drive
    - Piping
    - Civil work
- Power block
    - Steam turbine and generator
    - Electric auxiliaries
    - Thermal storage/heat transfer fluid system
    - Balance of Plant (BOP)
- Cooling system
- Water treatment
- Electrical

76 http://www.solarmillennium.de/index,lang2.html.

77 http://www.acciona-energia.com/default.asp?x=0002020401&lang=En.

78 National Renewable Energy Laboratory, "Overview on use of a Molten Salt HTF in a Trough Solar Field," NREL/PR-550, February 2003.

- Instrumentation and control
- Miscellaneous civil work

The solar field, thermal storage, and power block costs encompass approximately 95% of the total direct costs, as illustrated in Figure 25. Of these three highest cost categories, the solar field cost comprises 58% of the total direct cost. Figure 25 shows the solar field component cost breakdown. The component cost breakdown of the solar field reveals the support structures are 29%, the heat collection elements 19%, and the mirrors 18% of the solar field direct costs, for a total of 68% of the solar field direct costs.

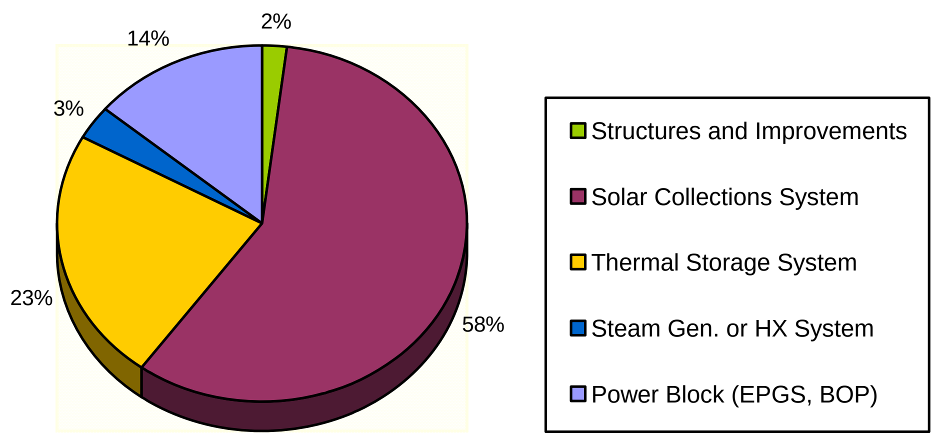

Figure 25. Major cost categories for parabolic trough plant

Source: NREL, *Assessment of Parabolic Trough and Power Tower Solar Technology…*

Table 19 provides a summary of SunLab's design, deployment, and cost projections for trough plants with the SEGS VI plant as the base case.

Table 19. Assessment of parabolic trough and power tower solar technology

	SEGS VI 1999	Trough 100 2004	Trough 100 2007	Trough 150 2010	Trough 200 2015	Trough 400 2020
Plant size, net electric, MWe	30	100	100	150	200	400
Plant size, gross thermal input, MWt	88	294	279	408	544	1,087
Thermal Storage, hr	0	12	12	12	12	12
Annual Plant Capacity Factor	22.2%	53.5%	56.2%	56.2%	56.2%	56.5%
Annual Solar-to-Electric Efficiency	10.6%	14.2%	16.1%	17.0%	17.1%	17.2%
Solar Field Design:						

	SEGS VI 1999	Trough 100 2004	Trough 100 2007	Trough 150 2010	Trough 200 2015	Trough 400 2020
Number of Collectors	800	4,768	1,269	1,808	2,392	4,783
Receivers per SCA	12	12	36	36	36	36
Number HCE	9,600	57,216	45,700	65,072	86,101	172,201
Number HCE Accumulative	9,600	66,816	112,516	177,588	263,688	435,889
Collector Size, m^2	235	235	817.5	817.5	817.5	817.5
Field Aperture Area, m^2	188,000	1,120,480	1,037,760	1,477,680	1,955,200	3,910,400
Heat Transfer Fluid System						
HTF Type	VP-1	VP-1	Hitec XL	Hitec XL	Hitec XL	Hitec XL
Fluid Volume, gallons	115,500	688,380	637,560	907,830	1,201,200	2,402,400
Direct Capital Cost:						
Structures & Improvements	2,526	7,279	6,538	8,097	9,596	16,284
Collector System	44,793	249,654	181,533	226,753	259,852	452,825
Thermal Storage System	0	95,807	42,475	57,426	76,567	153,135
Steam Gen. or HX System	4,304	9,964	9,227	11,161	12,772	19,394
EPGS	15,805	36,713	34,877	44,008	51,134	78,915
Balance of Plant	9,190	21,346	20,279	25,588	29,732	45,884
Total Direct Costs	76,619	420,763	294,929	373,033	439,654	766,438
Solar Collection System, $/$m^2$ field	250	234	184	161	140	122
Receivers, $/$m^2$ field	43	43	34	28	22	18
$/unit	847	847	762	635	508	400
Mirrors, $/ m^2 field	40	40	36	28	20	16
Concentrator Structure, m^2 field	50	47	44	42	39	36
Concentrator Erection, m^2 field	17	14	13	12	11	10
Drive, m^2 field	14	13	6	6	6	5

	SEGS VI 1999	Trough 100 2004	Trough 100 2007	Trough 150 2010	Trough 200 2015	Trough 400 2020
Interconnection Piping, m^2 field	11	10	3	3	3	2
Electronics & control, m^2 field	16	14	4	4	4	3
Header piping, m^2 field	8	7	7	6	6	5
Foundations/Other Civil, m^2 field	21	18	17	15	14	12
Other (spares, HTF, freight), m^2 field	17	17	11	10	9	8
Contingency, m^2 field	12	11	9	8	7	6
Direct Capital Cost, $/kWe						
Structures and Improvements, $/kWe	84	73	65	54	48	41
Solar Collection System, $/kWe	1,493	2,497	1,815	1,512	1,299	1,132
Thermal Storage System, $/kWe	0	958	425	383	383	383
System Generator of HX System, $/kWe	143	100	92	74	64	48
EPGS, $/kWe	527	367	349	293	256	197
Balance of Plant, $/kWe	306	213	203	171	149	115
Total Direct Cost, $/kWe	2,554	4,208	2,949	2,487	2,198	1,916

Source: NREL, *Assessment of Parabolic Trough and Power Tower Solar Technology…*

Table 20 and Figures 26 and 27 illustrate the SunLab projected total installed capital cost ($/kWe) compared to the more conservative (Sargent & Lundy) S&L values. Table 20 also shows the total installed capital cost based on achieving the annual net efficiencies projected by SunLab but not the projected cost reductions. The curves highlight the impact of the annual net efficiencies on the capital cost. The curves also indicate that additional cost reductions above the more conservative S&L values, due to technology improvements and increased deployment rates, will result in convergence of the capital costs toward the SunLab values.

Table 20. Comparison of total investment cost estimates ($/kWe): SunLab vs. S&L

	2004	2007	2010	2015	2020
Sunlab	$4,859	$3,408	$2,876	$2,546	$2,221
S&L – S&L Efficiencies	$4,816	$3,854	$3,562	$3,389	$3,220
S&L - SunLab Efficiencies	$4,791	$3,687	$3,331	$3,165	$2,725
S&L – No Storage	$2,453	$2,265	$2,115	$1,990	$1,846

Source: NREL, *Assessment of Parabolic Trough and Power Tower Solar Technology…*

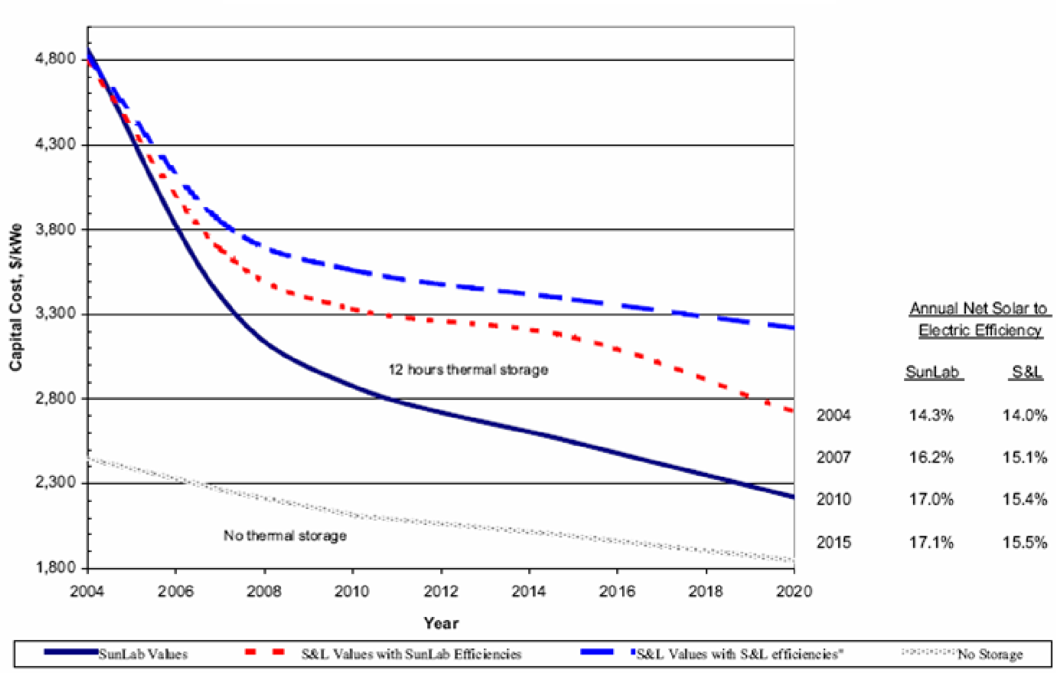

Figure 26 Capital cost comparison

Source: NREL, *Assessment of Parabolic Trough and Power Tower Solar Technology…*

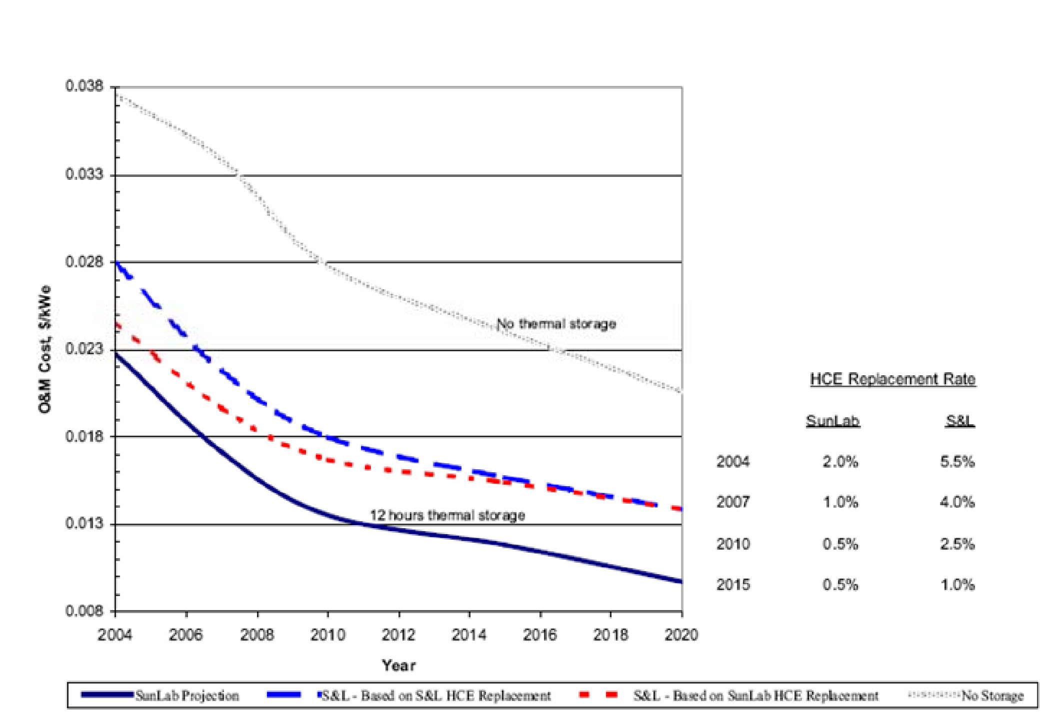

Figure 27. Levelized O&M cost comparison

Source: NREL, *Assessment of Parabolic Trough and Power Tower Solar Technology*…

Table 21. CSP plant capital cost breakdowns, 2005

($1,000s)	2007 100 MW*	2009 100 MW*	2011 150 MW*	2015 200 MW*
Site Work and Infrastructure	2,455	2,433	2,566	2,681
Solar Field	230,865	205,109	243,059	268,441
HTF System	10,009	9,895	11,896	13,542
Thermal Energy Storage	57,957	57,937	71,320	89,390
Power Block	38,754	38,754	48,899	56,818
Balance of Plant	22,533	22,533	28,432	33,036
Contingency	30,707	28,116	33,742	37,720
Total Direct Costs	393,280	364,776	439,915	501,627
Indirects	101,106	92,814	113,469	129,746
Total Installed Cost	494,386	457,590	553,384	631,373

*With 6 hours storage.

Source: Klein and Rednam, Comparative *Costs of California Central Station Electricity Generation Technologies.*

Table 22. Annual CSP O&M cost breakdowns, 2005

($1,000s)	2007 100 MW	2009 100 MW	2011 150 MW	2015 200 MW
Labor				
Administration	528	528	554	554
Operations	979	973	1,088	1,158
Maintenance	633	633	664	664
Total Labor	3,018	2,984	3,517	3,926
Miscellaneous	419	415	516	599
Service Contracts	263	259	352	435
Water Treatment	260	265	413	556
Spares and Equipment	669	651	870	1,040
Solar Field Parts and Materials	1,859	1,311	1,457	1,904
Annual Capital Equipment	226	218	320	418
Subtotal	3,695	3,119	3,928	4,953
Total	6,713	6,104	7,445	8,879

Source: Klein and Rednam, *Comparative Costs of California Central Station Electricity Generation Technologies.*

3.5.3. Solar – Photovoltaic (Single Axis)

Technical and Market Justification

Flat-plate photovoltaic (FPV) modules are commercially available worldwide. The solar electricity market is booming. By the end of 2007, the cumulative installed capacity of solar PV systems around the world had reached more than 9,200 MW. This compares with a figure of 1,200 MW at the end of 2000. Installations of PV cells and modules around the world have been growing at an average annual rate of more than 35% since 1998 (source: EPIA).

On pvresources.com's website almost 880 photovoltaic power plants (put into service in 2007 or earlier), each with peak power of 200 kWp or more, are listed. Cumulative power of all these photovoltaic power plants is about 955 MWp, and average plant power output is slightly more than 1.24 MWp. More than 390 large-scale photovoltaic plants are located in Germany, 225 in the United States, and more than 130 in Spain (source: pvresources).

The PV modules can be mounted on fixed tilt strucures or on one or two axis tracking devices. As of December 2007, the market share of fixed arrays was 73% of the total installed capacity in large-scale PV installations, only 27% were tracking systems (source: pvresources). However in situations with a high proportion of direct normal insolation, such as in California, the one-axis tracking system could increase the sunlight capture by up to 25% over traditional fixed-tilt systems, while significantly reducing land use requirements (source: Sunpower).

Primary Commercial Embodiment

There are currently no single-axis tracking utility-scale PV installations in California. The largest FPV (single-axis) project in the United States is 14 MWp at Nellis Air Force Base in Nevada.[79] The actual construction and installation required eight months to complete (although it was in the planning stage for three years) and was complete in December 2007. The project is a public-private partnership between the Air Force, Sunpower Corporation, Nevada Power Company, and MMA Renewable Ventures, a subsidiary of Municipal Mortgage and Equity.

The largest FPV (fixed tilt) project in the world is 60 MWp in Olmedilla, Castilla La Mancha, Spain.[80] Germany also has a utility-scale installation of FPV (fixed tilt) or 40 MWp in Waldpolenz, Brandis, Saxony, Germany.[81]

There is currently one utility-scale single-axis tracking PV systems planned for California and is planned to be in operation before 2018. PG&E has signed a contract with High Plains Ranch II, LLC, a subsidiary of SunPower Corporation, for 250 MW of high-efficiency PV solar power. The plant would be located in San Luis Obispo County's California Valley. The project is expected to begin power delivery in 2010 and be fully operational in 2012.

Cost Drivers

Market and Industry Changes

World solar PV market installations reached a record high of 5,750 MW in 2008, representing growth of 117% over the previous year.

Spain's PV market reached 2,600 MW in 2008 (annual growth rate of more than 400%) and now accounts for 44% of the world market. Germany reached a moderate increase to 1,500 MW, while the United States increased by 220% to 500 MW. It became the world's third largest market even in front of Japan (once the world leader) which stayed stable at a level of 230 MW. (source: BSW-Solar/EPIA/NNPVA)

Global solar cell production doubled in comparison to 2007 (3,436 MW). Chinese manufacturers raised their share in 2008. Meanwhile, thin film production reached a remarkable market share (2007: 12%).

In 2008, an interesting trend could be observed in Spain. Many large scaled PV installations have come into operation with capacities in the range of 20 to 60 MW (source: Photon).

Current Trends

In 2009 market experts and analysts expect the same rate of new installations as in 2008. The reasons for a reduction of the tremendous increase of the last two years are the financial crisis and the reductions of incentives especially in Spain and Germany.

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79 www.sunpowercorp.com

80 www.nobesol.com

81 www.juwi.de

The dynamic extensions of the production facilities in all steps of the production chain result in an increasing offer of solar modules. As a result this could lead to reduced prices and a change from seller's market to buyer's market.

The suppliers of silicon basic material for solar cells have announced plans to increase their production capacity to 150,000 tons per year, equivalent to 15 GW of solar cells (source: Photon).

The downward move in retail prices of last month has accelerated in March 2009. It is now three months in a row where the number of decreases has outpaced increases, and the same outcome has been true for four out of the last six months.

The last time the European price index dropped back in January, the move was driven mainly by exchange rate movements within Europe. This time it is a function of actual price reductions, which were widespread across several retailers. This caused the European index to fall 7 cents per watt. The last time there was a drop of this magnitude was in November 2001.

While European prices reacted to market conditions, United States' retailers also reduced prices. The movement in the United States index matched the drop seen in February.

These price drops are, in part, an outcome of the billions of dollars of investment made around the world in new manufacturing capacity for solar modules over recent years. As consumers demand this new energy source, so market size and production volumes allow the industry to bring down costs.

Cost Drivers

The primary general cost drivers for FPV single-axis systems are:

- Solar modules – Cost of basic material silicon, wafers, and solar cells. Assumption: producers have increased their capabilities to produce silicon dramatically. Overcapacities are expected for the next three years.
- Inverters – Mass production of inverters cuts costs.
- Installation – Efficiencies of solar modules: High-efficiency solar modules (mono-crystalline) reduce cost of installation. Cheaper amorphous silicon modules increase cost.
- Steel price – Steel doubled in price between January 2008 and September 2008 and again between September 2008 and January 2009.
- Balance of systems.
- Marketing sales taxes.
- Gross margin.

Current Costs

The Solarbuzz consultancy report analyzed the price of a single photovoltaic module by observing the prices of approximately 1.500 solar modules:

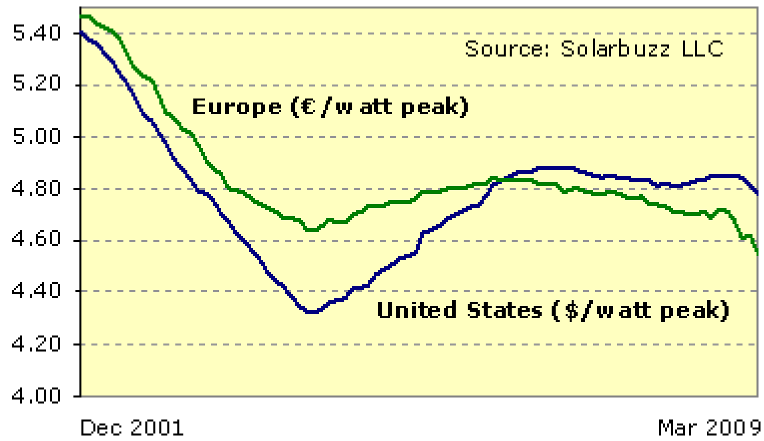

Figure 28. Solar module retail/price index, 125 watts and higher

Source: http://www.solarbuzz.com/Moduleprices.htm

As of March 2009, there are currently 293 solar modules priced below $4.75 per watt (€3.75 per watt) or 20.1% of the total survey. This compares with 250 priced below $4.75 per watt in February. The lowest retail price for a multicrystalline silicon solar module is $3.29 per watt (€2.60 per watt) from a German retailer. The lowest retail price for a monocrystalline silicon module is $3.48 per watt (€2.75 per watt), also from a German retailer.

The lowest thin film module price is at $2.47 per watt (€1.95 per watt) from a Germany-based retailer. As a general rule, it is typical to expect thin film modules to be at a price discount to crystalline silicon (for like module powers). This thin film price is represented by a 44 watt module.

The results of a yearly independent interview with 100 leading PV installation companies in Germany show that system prices for 100 kW roof-mounted PV installation been reduced to a level of $4.96 per watt (€3.92 per watt) (without sales tax) in the first quarter of 2009.

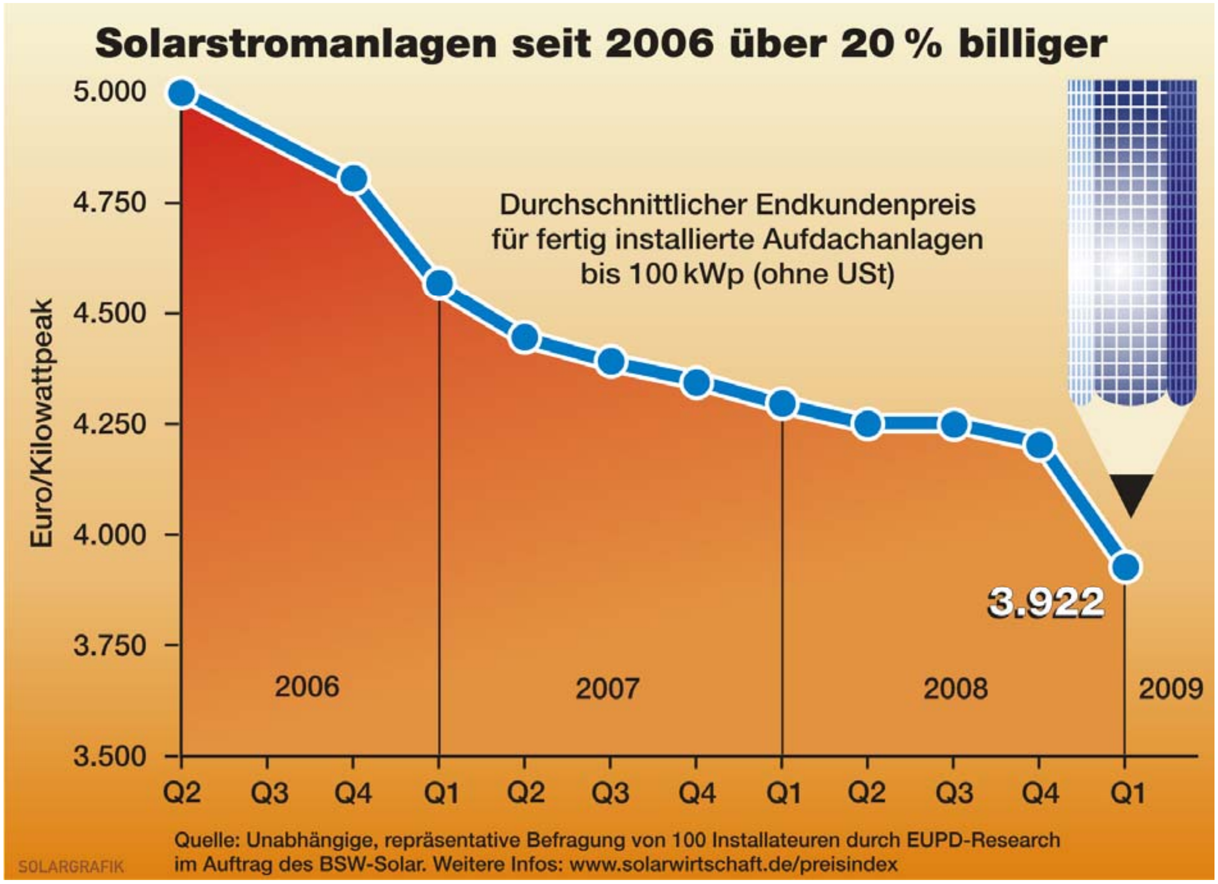

Figure 29. Solar power generation plant since 2006 over 20% cheaper

Source: http://www.solarwirtschaft.de/medienvertreter/infografiken.html

For a German installation of a PV power station (Waldpolenz/Rote Jahne) with a capacity of 30 MWp, total investment costs were reported at $4.49 per watt (€3.55 per watt).

For a second German installation of a PV power station (Königsbrück) with a capacity of 4.4 MWp, total investment costs were reported at $4.81 per watt (€3.80 per watt).

Both installations are fixed tilt.

Technology assumptions: The primary commercial embodiment of the technology for the cost model is 100,000 solar modules, multicrystaline silicon, area: app. 145,000 m², module efficiency: 14%, single-axis tracking, 200 DC/AC inverters.

Expected Cost Trajectories

The overall target of the short-term research described in the Strategic Research Agenda (SRA) issued by the European Community is for PV electricity to be competitive with consumer electricity (*grid parity*) in southern Europe by 2015. Specifically, this means reaching PV generation costs of €0.15 per kWh ($0.19 per kWh), or a turnkey system price of €2.5 per watt ($3.16 per watt). This system price arises from typical manufacturing and installation costs of <€2.0 per watt ($2.5 per Watt). All cost and price figures are in constant 2007 values.

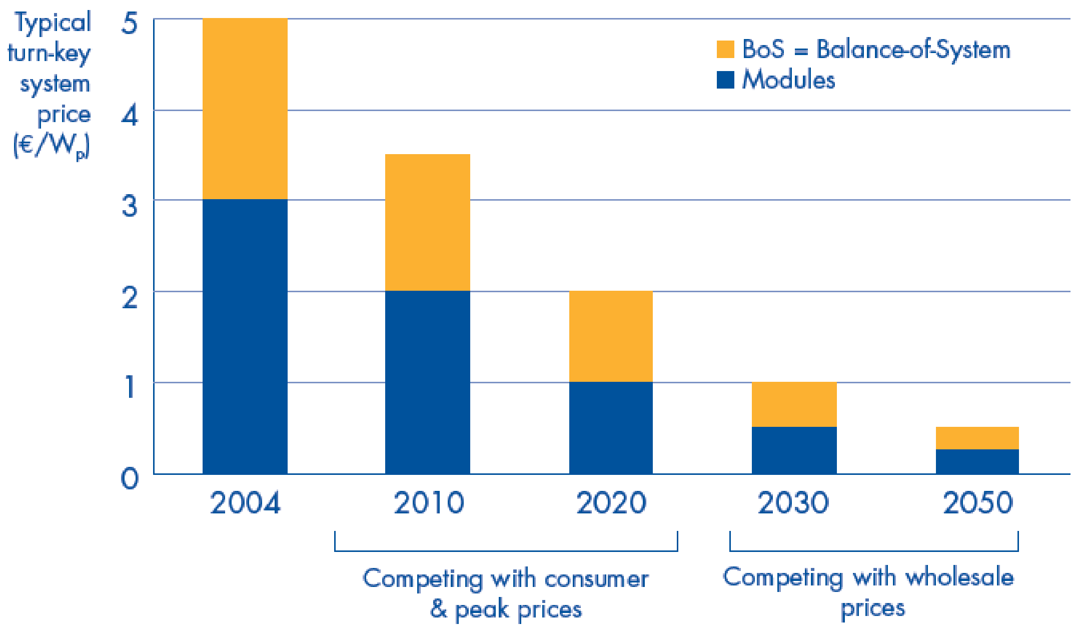

Figure 30. Typical turnkey system price

Source: cordis.europa.eu/technology-platforms/pdf/photovoltaics.pdf

Based on a detailed analysis of cost reduction potentials, the working group of the SRA decided that the same cost targets shall be used for all flat-plate PV module technologies considered: €0.8-1.0 per watt ($1.01-1.26 per watt) for technology ready by 2013 and implemented in large-scale production in 2015, €0.60-0.75 per watt ($0.76-0.95 per watt) in 2020, and €0.3-0.4 per watt ($0.38-0.51 per watt) in 2030. The targets are expressed as a range to reflect the efficiencies of different types of modules. To meet the overall, cross-technology cost targets, lower efficiency modules need to be cheaper than higher efficiency modules due to the area-related component of the BOS costs. These targets should not be interpreted as predictions. It is possible that some technologies will even exceed them. The efficiency targets quoted later in the SRA for each technology are considered as performance targets that should be met to meet the cost target. System costs and prices, it should be noted, depend on the specific application that the system is put to. Therefore the costs and prices mentioned in the SRA are only approximate.

3.6. Wind

3.6.1. Technology Overview

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

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

Some wind turbines use direct-drive generators and do not need a gearbox (being a critical component from a maintenance perspective).

Typical facilities today consist of 1.5 to 2.5 MW turbines atop 80 m towers.

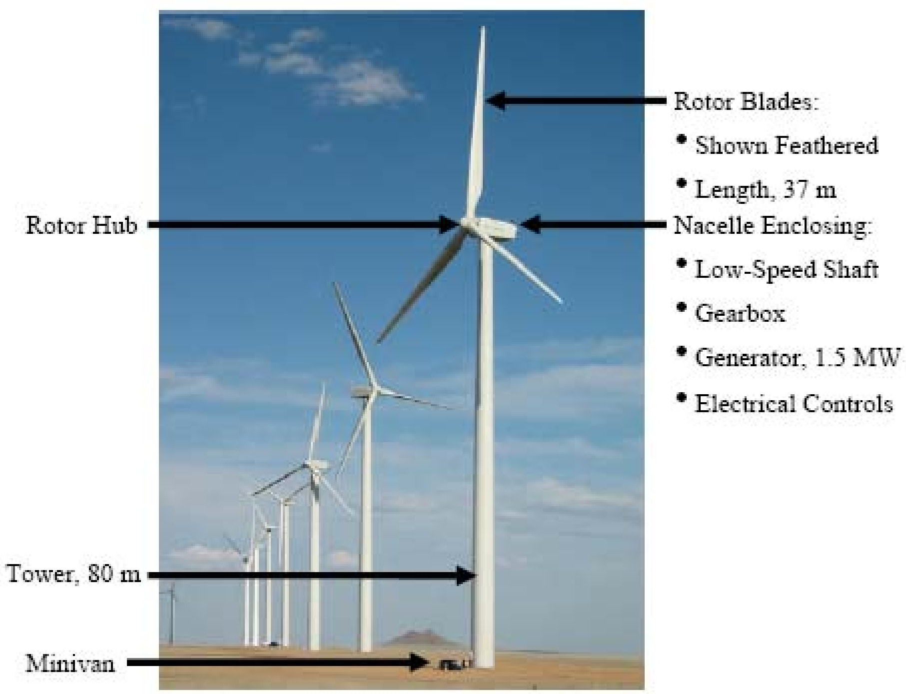

Figure 31. A modern 1.5 MW wind turbine installed in a wind power plant

Source: U.S. DOE, EERE, *20% Wind Energy by 2030.*[82]

82 U.S. Department of Energy. Energy Efficiency and Renewable Energy (EERE). *20% Wind Energy by 2030, Increasing Wind Energy's Contribution to U.S. Electric Supply*. DOE/GO-102008-2567, July 2008.

Wind plants can range in size from a few megawatts to hundreds of MW in capacity. Wind power plants are *modular*, which means they consist of small individual modules (the turbines) and can easily be made larger or smaller as needed. Turbines can be added as electricity demand grows. Today, a 50 MW wind farm can be completed in 18 months to two years. Most of that time is needed for measuring the wind and obtaining construction permits–the wind farm itself can be built in less than six months.

Some areas of California have good (Class 3/4) to excellent (Class 6/7) wind resources as seen in Figure 32.

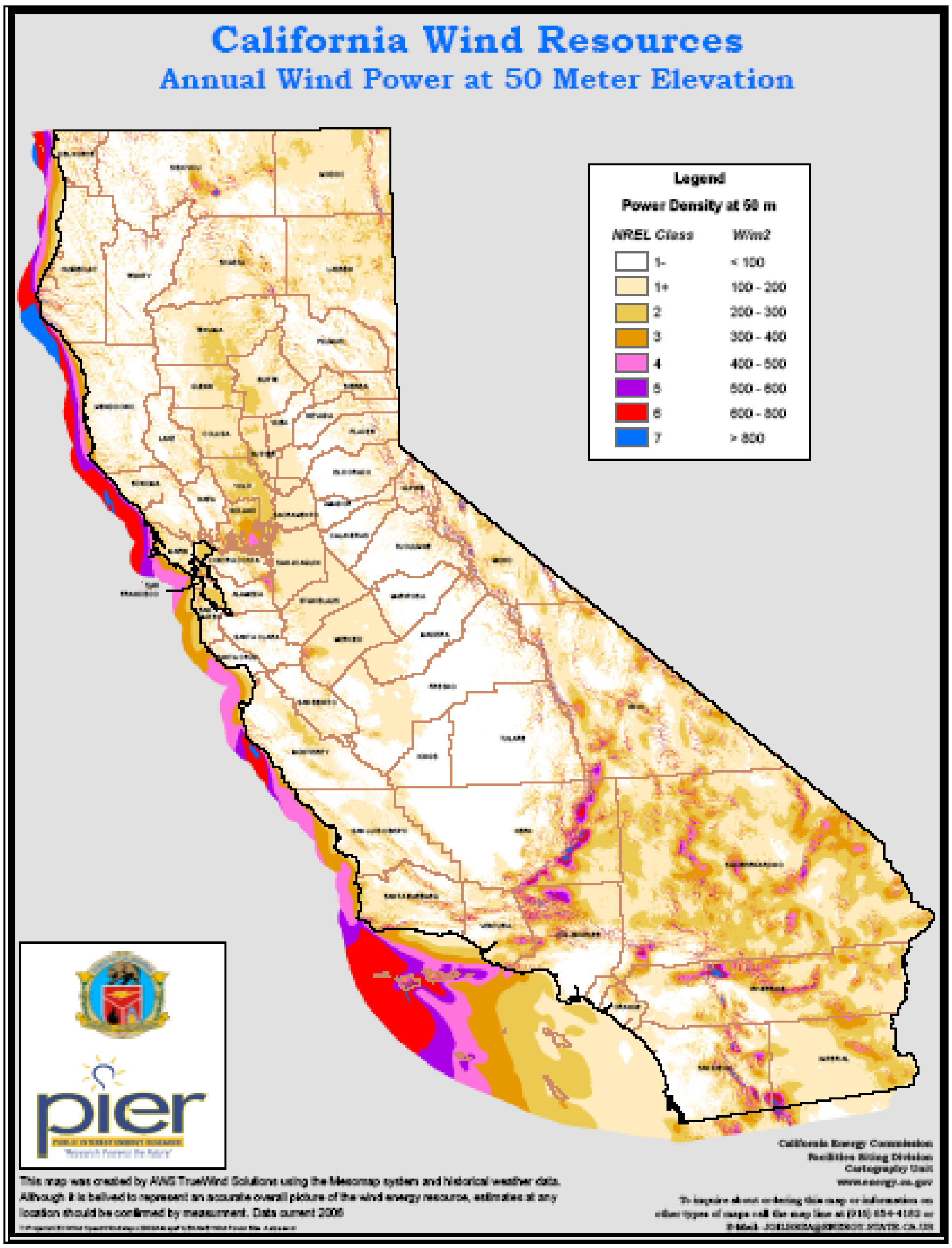

Figure 32. California wind resource map

Source: California Energy Commission PIER web site

California also has several wind power plants in operation. The specific locations of those plants are shown in Figures 33 and 34.

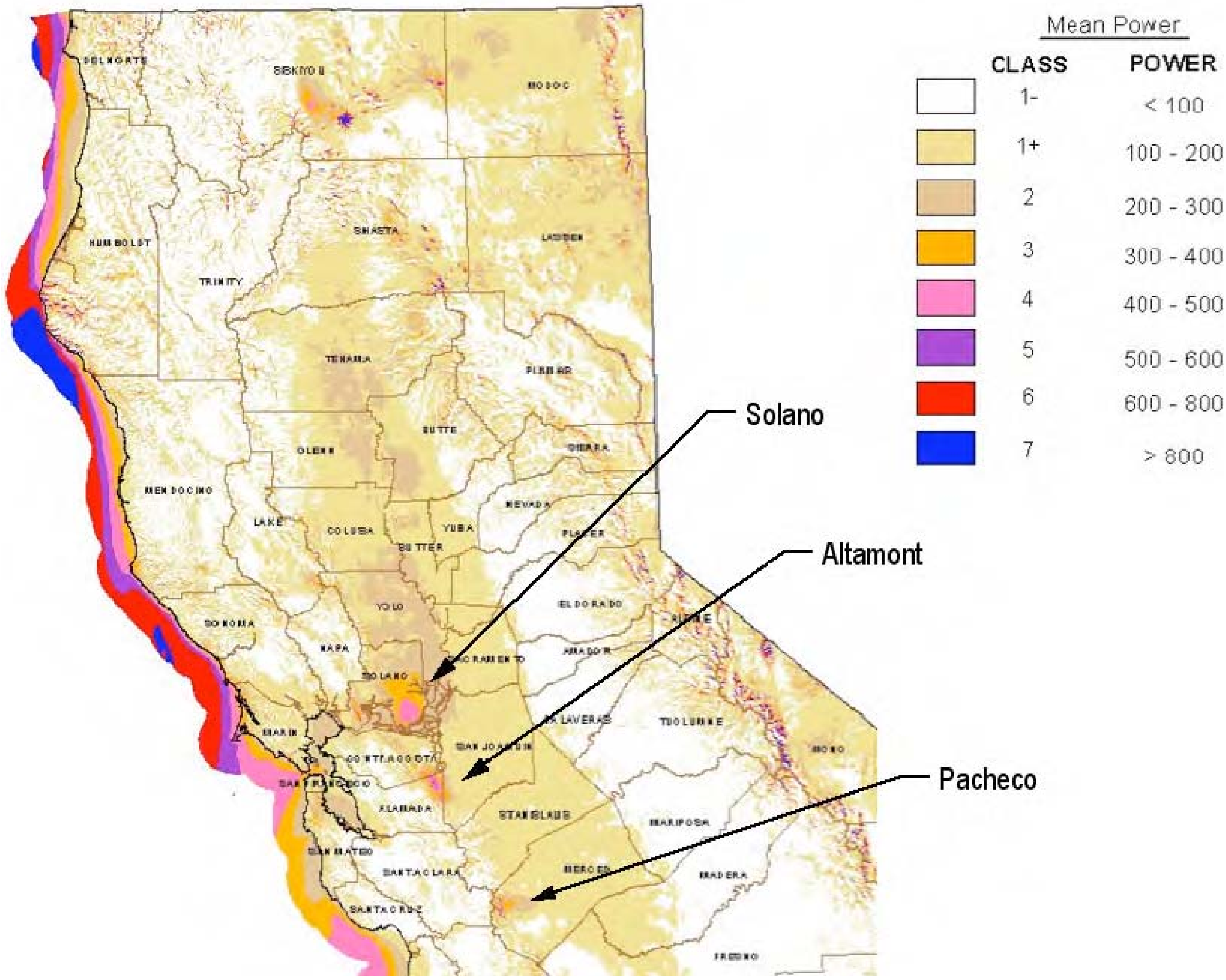

Figure 33. Wind resource map of Northern California

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

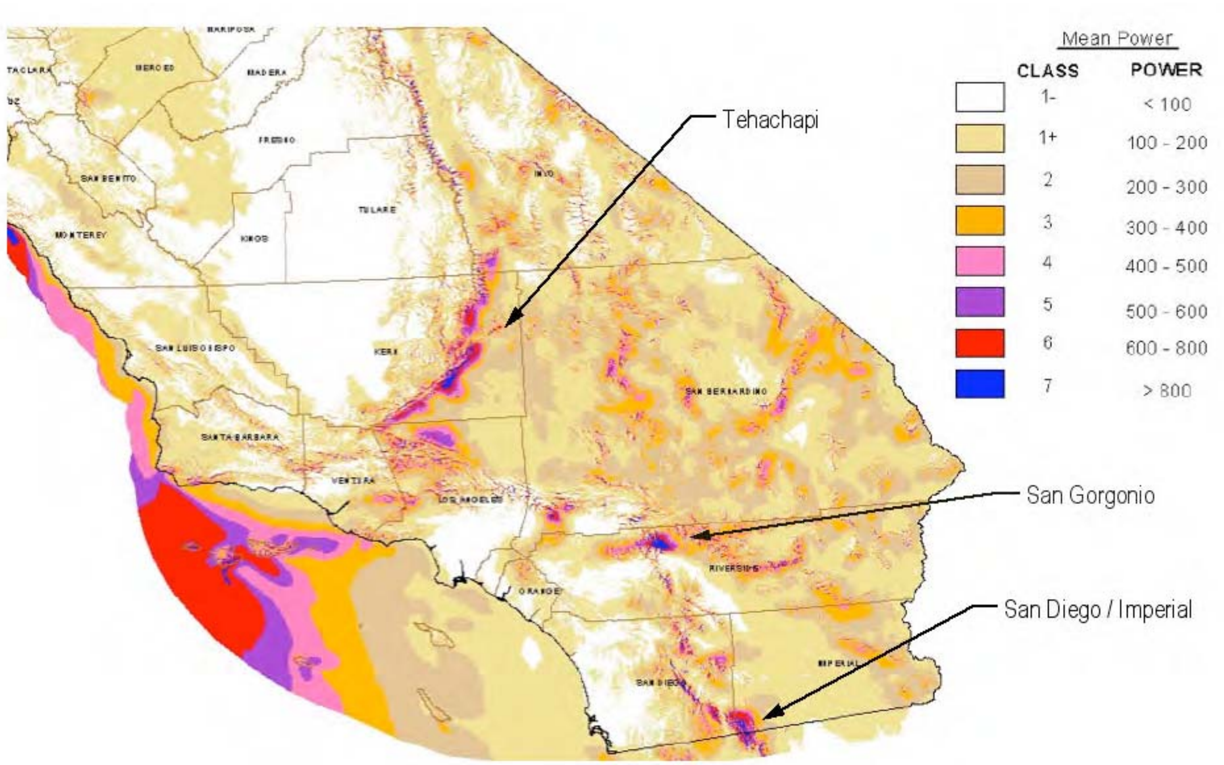

Figure 34. Wind resource map of Southern California

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

From Figures 33 and 34, wind classes were determined for the five California utility-scale wind facilities. Also average capacity factors from 1995 to 2005 were determined.[83]

Altamont:	Class 3-4	18.4
San Gorgonio:	Class 7	29.2
Tehachapi:	Class 7	26.6
Pacheco:	Class 2-4	16.6
Solano:	Class 4-5	17.7

Capacity factor can vary from year to year. Also wind turbines are becoming more efficient, with greater capacity ratings and higher towers, thus producing higher capacity factors. Trends in capacity factor for these sites, from 1995 to 2005 are shown in Figure 35.

83 Electronic Wind Performance Reporting System (eWPRS), http://wprs.ucdavis.edu/

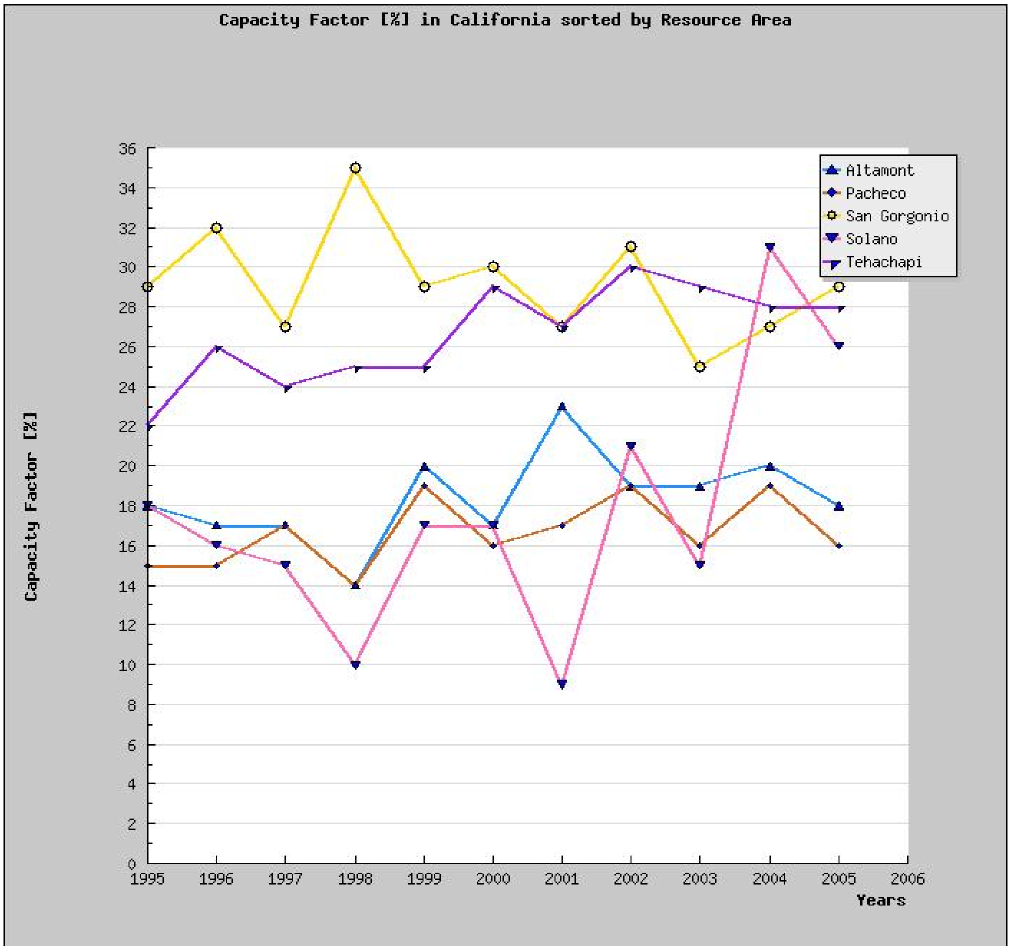

Figure 35. Capacity factor trends of California utility wind sites

Source: eWPRS web site

These capacity factors include both older and newer installed turbines, so is not necessarily representative of capacity factors that can be expected from new installations.

3.6.2. Onshore Wind – Class 5

Technical and Market Justification

According to the American Wind Energy Association (AWEA), in 2008, with over 8,500 MW installed, wind power provided 42% of all the new generating capacity added in the United States, up from less than 2% of new capacity added in 2004. With a total of 25,369 MW in operation at the end of 2008, the United States pulled ahead of the previous leader Germany (23,902 MW) both in wind energy production and in cumulative wind power generating capacity. The United States is also the world's largest market in terms of new installations (8,545 MW) added in 2008, ahead of China (6,300 MW).

Primary Commercial Embodiment

As of September 2008, California had 2517 MW of installed wind turbine capacity (source: AWEA). Wind plant installations are modular with the capability to add new turbines within each development, thus increasing overall plant size. Recent wind turbine installations (since 2006) range in size from 1 MW to 3 MW (source: AWEA[84]).

Wind plant size in California varies dramatically. As an illustration, wind plant installations since 2003 are shown in Table 23. Plant sizes vary from less than 1 MW to 150 MW, and many of these installations are within the same general area as pre-existing installations, which illustrate the modular nature of this technology. California installations listed by AWEA total 116 wind plants.

Utility-scale wind turbine installations will continue to increase in California through 2018 and beyond. A growing trend is toward larger turbines. There are currently several 5 MW wind turbines in the prototype stage.[85] It is uncertain whether such large turbines will be routinely installed for onshore applications or will be relegated only to the offshore market.

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84 http://www.awea.org/projects/Projects.aspx?s=California

85 Musial, Walt, Sandy Butterfield, and Bonnie Ram. *Energy from Offshore Wind*. National Renewable Energy Laboratory, NREL/CP-500-39450, February 2006.

Table 23. California utility wind plant installations since 2003

Name	Location	Power Capacity (MW)	Units	Turbine Size	Turbine Mfr.	Developer	Owner	Power Purchaser	Year Online
Shiloh II	Northern California	150	75	2	REPower	enXco	enXco	PG&E	2009
Edom Hills repower	Southern California	20	8	2.5	Clipper	BP Alternative Energy	BP Alternative Energy	SCE	2008
Alite Wind Farm	Southern California	24	8	3	Vestas	Allco/Oak Creek Energy		California Portland Cement	2008
Dillon	Southern California	45	45	1	Mitsubishi	Iberdrola Renewables	Iberdrola Renewables	Southern California Edison	2008
Solano Wind Project	Solano	63	21	3	Vestas	Sacramento Municipal Utility District	Sacramento Municipal Utility District	Sacramento Municipal Utility District	2007
Buena Vista	Altamont Pass	38	38	1	Mitsubishi	Babcock & Brown	Babcock & Brown	Pacific Gas & Electric	2006
Shiloh Wind Power Project	Solano County	150	100	1.5	GE Energy	PPM Energy	PPM Energy	PG&E, Modesto Irrigation District & City of Palo Alto Utilities	2006
Solano IIA	Solano County	24	8	3	Vestas	Sacramento Municipal Utility District	Sacramento Municipal Utility District	Sacramento Municipal Utility District	2006
Coram Energy (Aeroman repower)	Tehachapi	10.5	7	1.5	GE Energy	Coram Energy	Coram Energy	Southern California Edison	2005
Kumeyaay Wind Power Project	East of San Diego	50	25	2	Gamesa	Superior Renewable Energy	Babcock & Brown	San Diego Gas & Electric	2005
Victorville Wind Project	Victorville prison	0.75	1	0.75	Vestas	NORESCO	NORESCO	Victorville Prison	2005
Victory Garden	Tehachapi	0.66	1	0.66	Vestas	Caithness	Caithness	Southern California Edison	2005
Victory Garden	Tehachapi	6	8	0.75	Zond	Caithness	Caithness	Southern California Edison	2005
Coram Energy (Aeroman repower)	Tehachapi	4.5	3	1.5	GE Energy	Coram Energy	Coram Energy	Southern California Edison	2004
Diablo winds	Altamont Pass	20.46	31	0.66	Vestas	FPL Energy	FPL Energy	Pacific Gas & Electric	2004
Lake Palmdale	Palmdale	0.95	1	0.95	Vestas	Palmdale Water District	Palmdale Water District	Palmdale Water District	2004
Oasis Power Partners	Tehachapi	60	60	1	Mitsubishi	enXco	enXco	San Diego Gas & Electric	2004
Solano Wind Project, phase II	Solano County	4.62	7	0.66	Vestas	FPL Energy	Sacramento Municipal Utility District	Sacramento Municipal Utility District	2004
Aeroman repower (2003)	Tehachapi	3	2	1.5	GE Energy	Coram Energy	Coram Energy	Southern California Edison	2003
CalWind II CEC	Tehachapi	8.58	13	0.66	Vestas	CalWind Resources		Southern California Edison	2003
High Winds	Solano	162	90	1.8	Vestas	FPL Energy	FPL Energy	PPM Energy	2003
Karen Avenue II (San Gorgonio Farms)	San Gorgonio	4.5	3	1.5	GE Energy	San Gorgonio Farms	San Gorgonio Farms	Southern California Edison	2003
Mountain View Power Partners III	San Gorgonio	22.44	34	0.66	Vestas	PPM Energy	PPM Energy	San Diego Gas & Electric	2003
Solano Wind Project, phase I	Solano County	10.56	16	0.66	Vestas	Sacramento Municipal Utility District	Sacramento Municipal Utility District	Sacramento Municipal Utility District	2003
Whitewater Hill	San Gorgonio	4.5	3	1.5	GE Energy	Cannon Power Corp.	Cannon Power Corp.		2003

Source: AWEA Project Database

Cost Drivers

Market and Industry Changes

There are several key market and industry changes since 2007 that have materially affected wind turbine installation costs.

- The value of the United States' dollar relative to the Euro has shown an increase since mid-2008.
- United States' manufacturing of turbine parts has been increasing.

These changes and their significance are further discussed below.

Current Trends

The cost of wind power installations showed a steady decline from the early 1980s until 2002. Since then costs have increased steadily. This trend is from a Lawrence Berkeley National Laboratory (LBNL) study of actual installations over time and shown in Figure 36.[86]

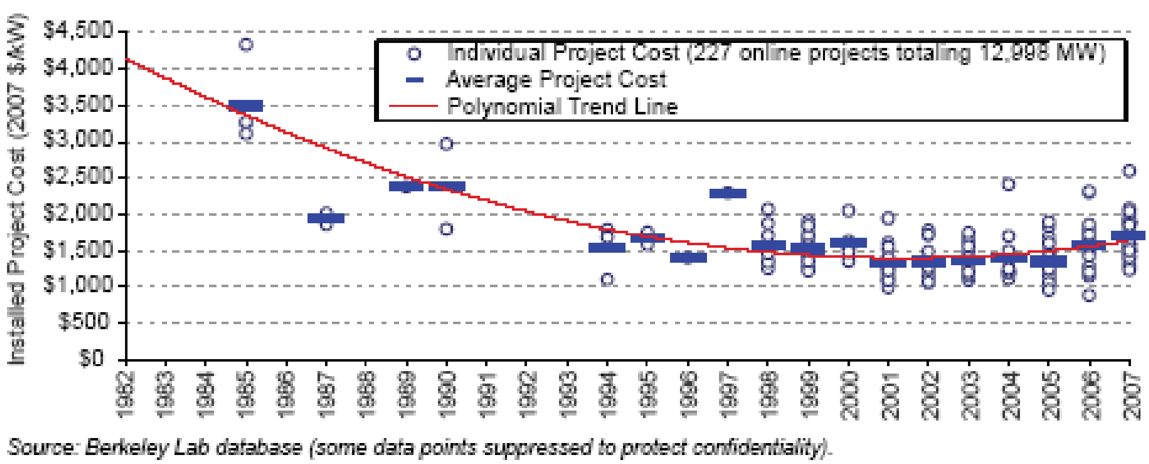

Figure 36. Installed wind project costs over time

Source: Wiser and Bollinger, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007.*

These cost increases are driven by several market factors as discussed below (Wiser 2007):

- Increased cost for commodities (affecting turbine prices).
- Drop in value of the United States' dollar relative to the euro.
- Improved sophistication of turbine design.

86 Wiser, Ryan and Mark Bolinger. *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*. U.S. Department of Energy. EERE, May 2008.

- Upscaling of turbine size (and hub height).
- Shortages in certain turbine components.
- A general move by manufacturers to improve their profitability.

These factors are cited as reasons for wind turbine price increases of 9% from 2006 to 2007. But some of these factors have actually shown a reversal since 2007.

- The value of the United States' dollar relative to the euro has shown an increase from mid-2008 through April 2009 (Figure 38).
- United States' manufacturing of turbine parts have increased from 30% in 2005 to 50% in 2008,[87] thus reducing the value of the United States' dollar relative to the euro as a cost driver.
- The increase in United States' manufacturing capacity also results in a reduction on shortages of certain turbine components.
- There is speculation that direct drive[88] or multiple generator drive train[89] wind turbine configurations will ultimately reduce costs. Currently these technologies are in the development/demonstration stages.

<u>Increased Cost for Commodities:</u>

A wind turbine is made primarily of steel (approximately 90%) and other materials. Cost trends for these raw materials are shown in Figure 37.

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87 Cheeseman, G.M. *U.S Wind Turbine Manufacturing Will Increase*. www.Clesias.com http://www.celsias.com/article/us-wind-turbine-manufacturing-will-increase/

88 deVries, Eize. "REW Exclusive: Siemens New 3.6 MW Direct-Drive 'Concept' Wind Turbine." *Renewable Energy World*, July 4, 2008. http://www.renewableenergyworld.com/rea/news/article/2008/07/rew-exclusive-siemens-new-3-6-mw-direct-drive-concept-wind-turbine-52963

89 Cotrell, J.A. *A Preliminary Evaluation of a Multiple-Generator Drivetrain Configuration for Wind Turbines.* Presented at American Society of Mechanical Engineers Wind Energy Symposium, NREL/CP-500-31178, January 2002.
http://www.osti.gov/bridge/servlets/purl/15000704-XNgzBn/native/15000704.PDF.

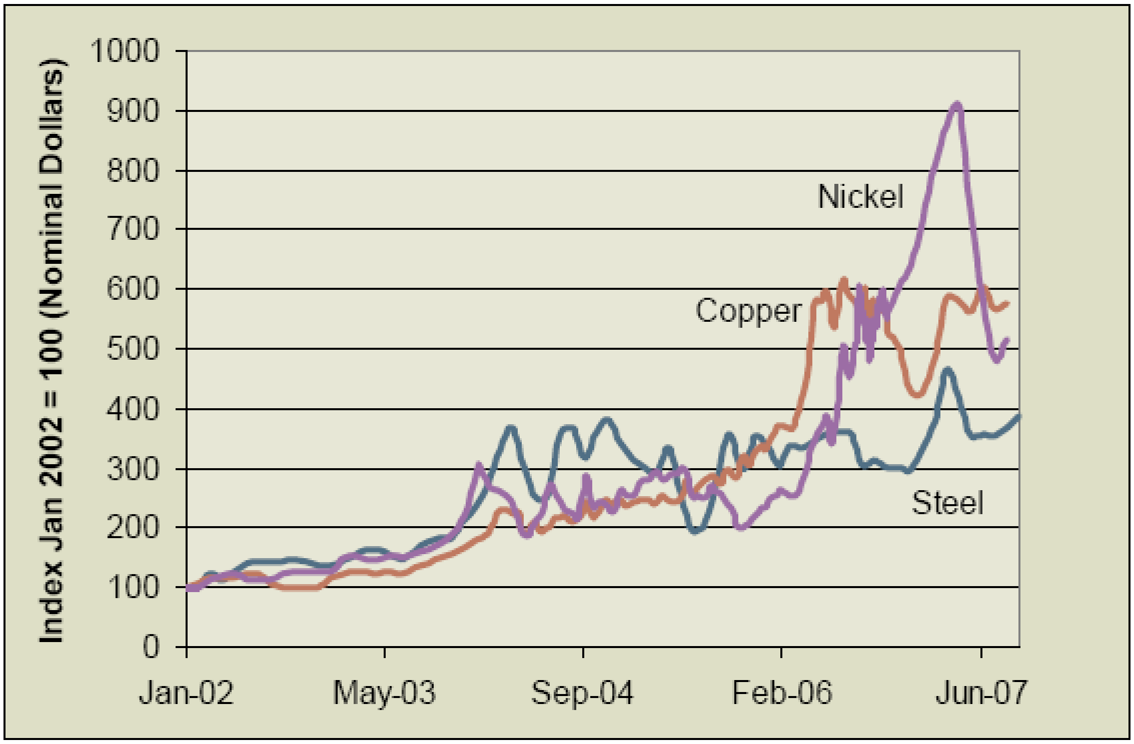

Figure 37. Metal prices Jan. 2002 – Sept. 2007 (London Metal Exchange)

Source: O'Connell and Pletka, *20 Percent Wind Energy Penetration in the United States*. [90]

Drop in Value of the United States' Dollar Relative to the Euro:

One factor in the cost increase for the wind industry since 2002 has been the drop in value of the dollar against the euro. Prior to 2008, the majority of wind turbine components have been manufactured in Europe, but this trend has started to reverse due to more United States' manufacturing. As the value of the United States' currency dropped against the euro, turbine prices have increased in United States' dollar terms (Black & Veatch 2007). But this trend in value of the United States' dollar against the euro has shown a reversal over the past year. This is illustrated in Figure 38.

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90 O'Connell, Ric and Ryan Pletka, et al. *20 Percent Wind Energy Penetration in the United States: A Technical Analysis of the Energy Resource*. Black & Veatch Project: 144864, October 2007.

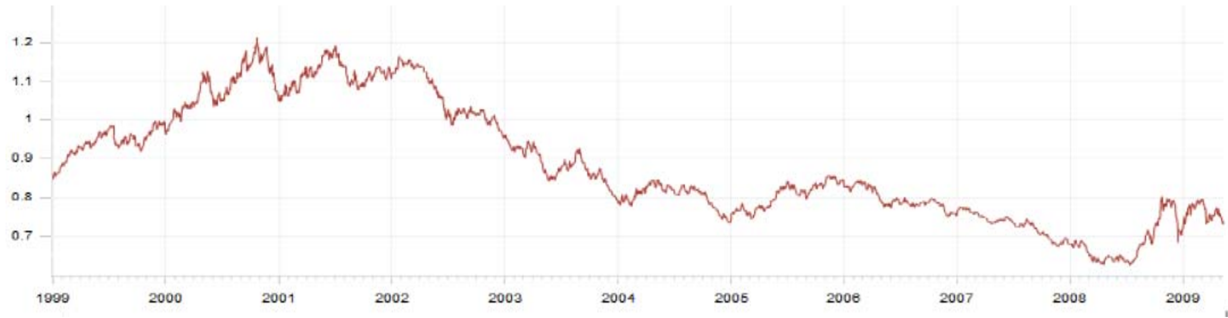

Figure 38. U.S. dollar vs. euro, Jan. 1999 through April 2009 (European Central Bank)
Source: European Central Bank.

<u>Improved Sophistication of Turbine Design</u>

Such improvements will include improved efficiencies resulting in increased capacity factors. Figure 39 shows capacity factor trends from wind turbine installations over time. This upward trend cannot be attributed only to turbine design. Increased hub heights and increased care in selecting turbine location for higher wind sites can increase capacity factor. The increase in hub height and care in site selection can also contribute to increased installed costs.

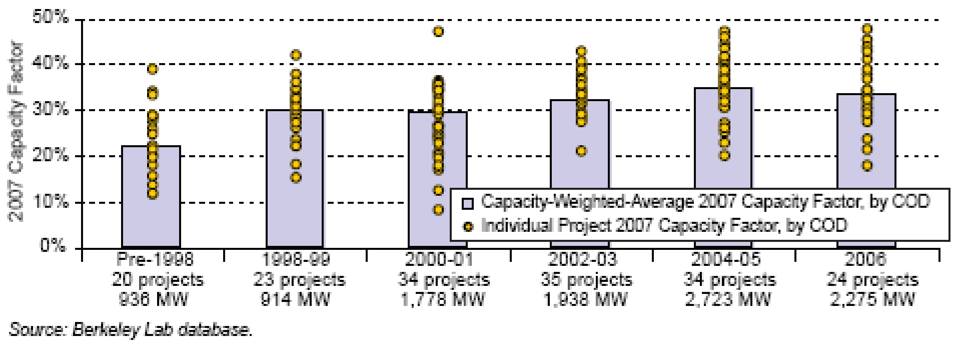

Figure 39. 2007 Project capacity factors by commercial operation date
Source: Wiser and Bollinger, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007.*

Projections of future capacity factor have been performed (Black & Veatch 2007) by analyzing monthly data from over 5,000 MW of wind plants installed in the Midwest from 2000 to 2005. The research team believes the Midwest installation analysis is transferable to California even though the topography is quite different, since capacity factors were determined by wind power class. One region, the Midwest, was chosen for the analysis with the purpose of performing a relative comparison. A regression curve was developed for the various wind classes and is shown in Figure 40.

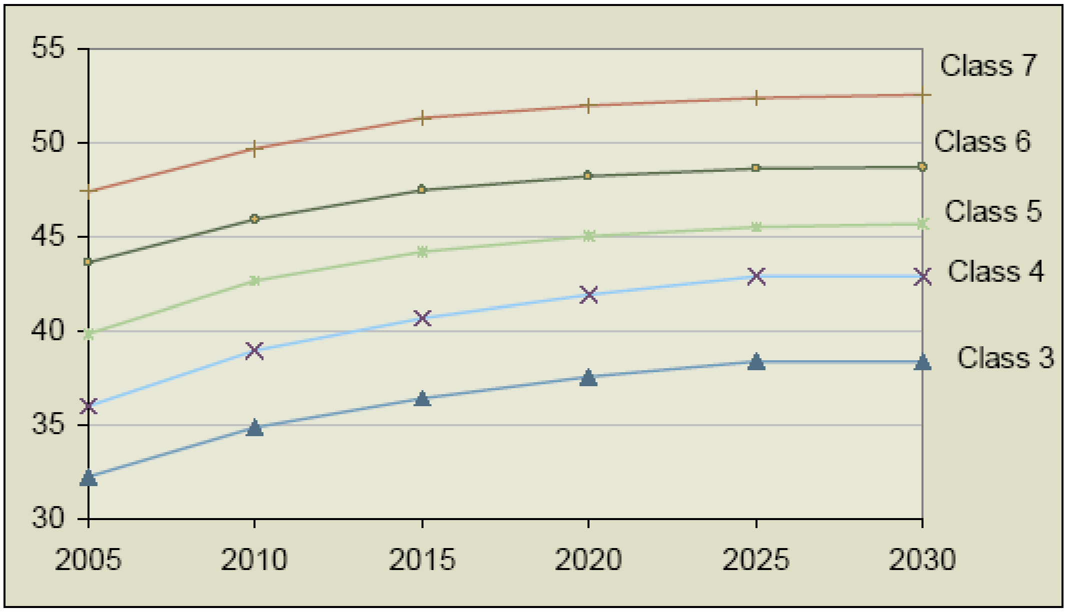

Figure 40. Onshore capacity factor by installed year and class
Source: O'Connell and Pletka, *20 Percent Wind Energy Penetration in the United States*.

UpScaling of Turbine Size (and Hub Height):

Wind turbine size (ratings in MW), which drives rotor diameter and hub height, has increased over time. The increased equipment costs will be at least partially offset by increased capacity factor.

Table 24. Size distribution and number of turbines over time

Turbine Size Range	1998-99	2000-01	2002-03	2004-05	2006	2007
	1,018 MW	1,758 MW	2,125 MW	2,776 MW	2,454 MW	5,329 MW
	1,425 turbines	1,987 turbines	1,757 turbines	1,960 turbines	1,532 turbines	3,230 turbines
0.05-0.5 MW	1.3%	0.4%	0.5%	1.8%	0.7%	0.0%
0.51-1.0 MW	98.5%	73.9%	43.4%	18.5%	10.7%	11.0%
1.01-1.5 MW	0.0%	25.4%	43.5%	56.0%	54.2%	48.6%
1.51-2.0 MW	0.3%	0.4%	12.5%	23.6%	17.6%	24.1%
2.01-2.5 MW	0.0%	0.0%	0.0%	0.1%	16.3%	15.0%
2.51-3.0 MW	0.0%	0.0%	0.1%	0.0%	0.5%	1.3%

Source: AWEA project database.

Source: Wiser and Bollinger, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007.*

Shortages in Certain Turbine Components

United States wind power capacity surged by 46% in 2007, with 5,329 MW added and $9 billion invested (Wiser 2007). Annual growth of the wind turbine industry in the United States is shown in Figure 41, which has contributed to shortages in the industry. But as United States' manufacturing capacity increases, turbine component shortages should be less of an issue.

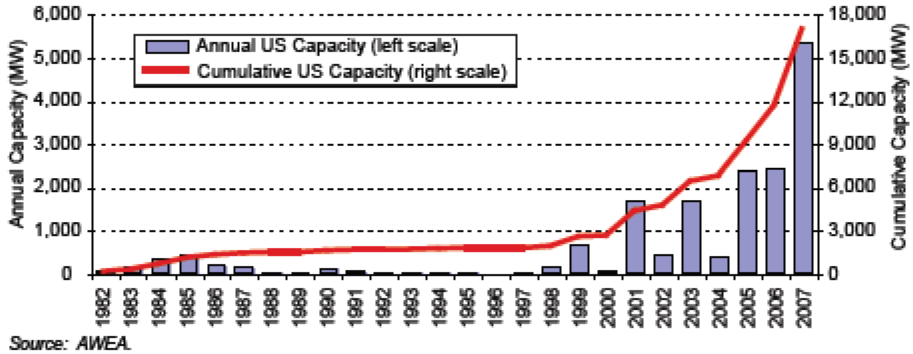

Figure 41. Annual and cumulative growth in U.S. wind power capacity

Source: Wiser and Bollinger, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007.*

<u>A General Move by Manufacturers to Improve Wind Profitability</u>

Since 2003, wind power generation costs have been cost-competitive with other forms of generation but have been generally increasing as wholesale power prices increase.

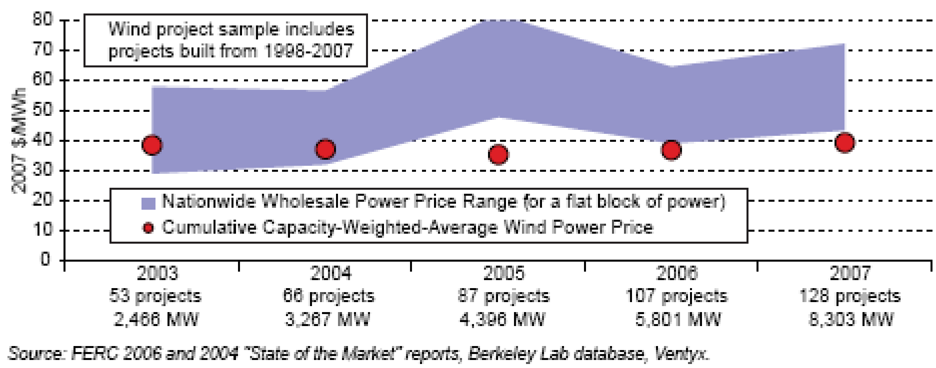

Figure 42. Average cumulative wind and wholesale power prices over time

Source: Wiser and Bollinger, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007.*

Since wind produced electricity is becoming more valuable with increased electric prices, increased development of the technology can occur (resulting in higher capacity factors, hub heights, and turbine efficiencies), and more effort can be put into locating the turbines in the best wind sites. Wind turbine manufacturers and wind site developers are then able to charge more for their products.

Cost Drivers

Each of the current trends listed above can also be considered cost drivers. Each of those trends primarily affects turbine prices, which are typically 75% of overall project installation costs (Black & Veatch 2007). General project cost drivers are listed below:

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

Also when using national average cost data, adjustments must be made for differences in California. A 9% increase from national cost data should be applied to wind turbine project installations in California (Black & Veatch 2007).

Some consider economies of scale to be a cost driver for lowering costs. Since wind power plants are a modular technology, very few economies of scale have been seen from larger installations (Wiser 2008), as shown in Figure 43.

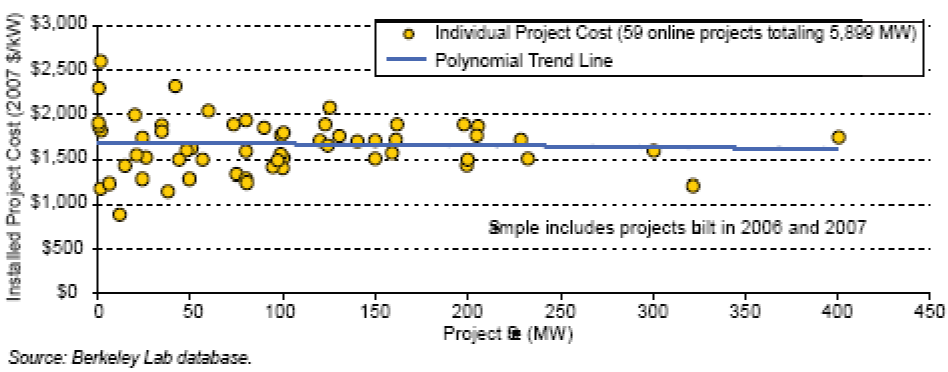

Figure 43. Installed wind project costs as a function of project size: 2006-2007 projects
Source: Wiser and Bollinger, Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007.

Current Costs

The current costs were determined through the following steps:

- Use installed costs from the 2008 DOE study[91] ($2007).

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91 Wiser, Ryan and Mark Bolinger. *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*. U.S. Department of Energy. EERE, May 2008.

- Project costs to $2009 adjusting from $2007 per inflation (adjusted 6.75% per Moody's price inflators from 2007 to 2009).
- Adjust national average costs to California values (multiplying by 1.09).
    - Average 2007 installed cost: $1,710/kW
    - Average 2009 installed cost: $1825/kW
    - California 2009 installed cost: $1,990/kW

Also, reported installed United States' costs for 2007 ranges from $1,240/kW to $2,600/kW (Wiser 2008). Adjusting to $2009 for California, the high and low costs are as follows:

- High 2009 installed cost for California: $3,025/kW
- Low 2009 installed cost in California: $1,440/kW

Fixed O&M is estimated to have a national average cost of $11.50/kW (Black & Veatch $2006), based on review of recent projects. This is increased for California by 9%. Fixed O&M costs consist of property taxes, insurance, site maintenance, legal fees, labor, and miscellaneous items.

It is assumed these factors can vary by approximately ±25% to obtain the high and low fixed O&M costs. The 25% value was determined through inspection of O&M variability (Wiser 2008).

Adjusting to $2009, fixed O&M cost: $13.70/kW:

Average:	$13.70/kW
High:	$17.13/kW
Low:	$10.28/kW

Variable O&M costs are estimated to have a national average cost of $7.00/MWh (Black & Veatch $2006), based on review of recent projects. Variable O&M is driven by number of turbines and will decline as turbine reliability improves. Since the trend is toward larger wind turbines, resulting in fewer turbines per site, and higher quality products, variable O&M is expected to decline over time. Based on these factors, Black & Veatch estimates current variable O&M costs at $7.00/MWh and 2030 costs at $4.40/MWh, with an average of $5.00/MWh (all in $2006).

Adjusting to $2009, variable O&M cost:

Average:	$5.50/MWh
High:	$7.66/MWh
Low:	$4.82/MWh

Expected Cost Trajectories

Recent cost trajectories show a steep increase in wind turbine installed costs over the past several years. This report explains the various causes behind the increase. It is unreasonable to believe the costs will continue to climb. Many of the factors that have contributed to cost increases since 2002 have shown a reversal over the past two years. These factors include:

- Value of United States' dollar versus the euro declined from 2002 to mid-2008, but has shown a reversal since then.
- Increases in global and United States-based manufacturing capacity for wind turbines.
- Basic commodity prices (e.g., steel, copper) have steadied and in some cases declined.

The research team has concluded a learning effect in wind turbine installations will be realized, but it is expected to be modest. The main driver being that wind generation in conjunction with the production tax credit (PTC) and investment tax credit (ITC) is currently cost competitive with other forms of generation. The learning effect is estimated between 0.33% to 0.5% per year.

3.6.3. Onshore Wind – Class 3/4

The entire discussion on Class 5 wind directly applies to Class 3/4 wind. The only difference is in the capacity factor, which can be determined from Figure 40. Capacity factor ranges for Class 3/4 wind turbine installations are given below:

Average: 37%

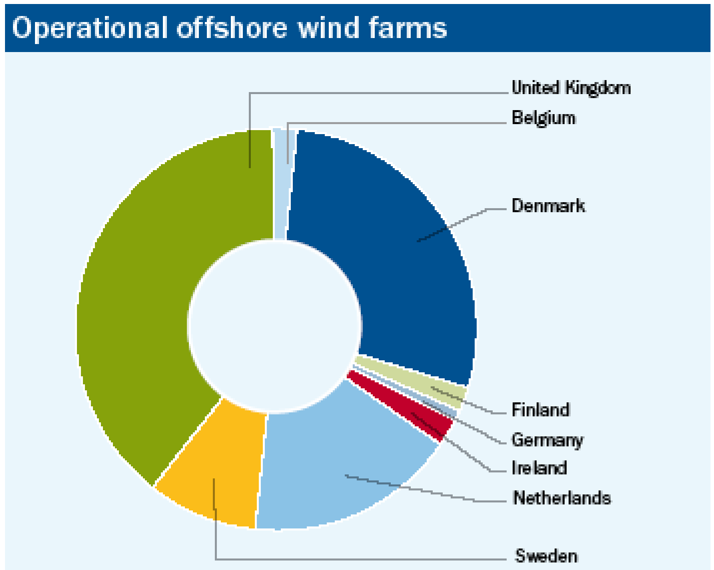
High: 41%

Low: 34%

3.6.4. Offshore Wind – Class 5

Technical and Market Justification

Offshore wind is an emerging technology in the United States and an operational one in Europe. There are no installations in the United States, but by the end of 2008 a total of over 1,400 MW of offshore wind farms have been in operation around Europe; in the coastal waters of Denmark, Ireland, Netherlands, Sweden, the United Kingdom, Germany, Belgium, and Finland. This represents around 2% of the cumulative installed capacity of wind power in the European Union (EU) (source: EWEA). A breakdown of offshore wind installations by country is provided in Figure 44.



United Kingdom	39%	590,80 MW
Denmark	28%	409,15 MW
Netherlands	17%	246,80 MW
Sweden	9%	133,30 MW
Belgium	2%	30,00 MW
Ireland	1%	25,20 MW
Finland	2%	24,00 MW
Germany	1%	12,00 MW
TOTAL		1,471,33 MW

Figure 44. European offshore wind installations
Source: EWEA, *Seas of Change: Offshore Wind Energy.*

Several offshore wind power installations have been proposed in the United States, but many have been postponed or cancelled purportedly due to high project costs.[92] Other issues fostering opposition have been the perceived impact to scenery from valuable coastal properties, bird migration patterns, and hazards to marine and air navigation.[93] Offshore wind has been seeing a slow start in the United States but should one day become a reality in many parts of the country. Off the Delaware shore, the first offshore wind farm to be developed in the United States has already sold one-third of the power that will be generated during its first 25 ***years of operation before a turbine is even placed in the water.[94]

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92 O'Connell, Ric and Ryan Pletka, et al. *20 Percent Wind Energy Penetration in the United States: A Technical Analysis of the Energy Resource*. Black & Veatch Project: 144864, October 2007. 5-10.

93 Snyder, John "Despite Opposition, Offshore Wind Farms Seem Poised to Make Their Mark." *Professional Mariner Magazine*, September 2007.

94 Environmental News Service. "First U.S. Sale of Offshore Wind Power Signed." January 2008.

Primary Commercial Embodiment

There are currently no offshore wind installations in California.

The primary focus of offshore wind farms in the United States has been off the Atlantic coast. Strong wind resources also exist off the Pacific coast, but these are primarily in deep waters, which present technical challenges.[95] Until these challenges associated with deep water wind platforms are resolved, offshore wind development in California will be limited.

Cost Drivers

Market and Industry Changes

Market and industry changes have been presented in the Onshore Wind section, which also apply to offshore wind. There are additional changes that apply to offshore.

Due to Delaware's mandate to guarantee stable prices for electricity (House Bill 6) and its RPS requirements of 20% renewable energy by 2019 (Senate Bill 74), Bluewater Wind negotiated a Power Purchase Agreement (PPA) with Delmarva Power for power from offshore wind. Bluewater is proposing a 450 MW plant.[96]

New United States' policy framework, including commitments from the Department of the Interior, the Minerals Management Service, and the FERC encourage the development of offshore wind energy generation capacity.[97]

Another 30 state legislators have signed onto a letter to Kenneth L. Salazar, U.S. Secretary of the Interior, to quickly approve the Cape Cod Wind Farm project off the Massachusetts coast.[98]

In Europe, the offshore wind industry is flourishing. The EWEA's statistics show that a total of 1,471 MW was installed worldwide by the end of 2008, all of it in European Union (EU) waters.

Since December 2007, the number of countries that host offshore wind turbines has increased from five to nine–that is, one third of EU Member States.

In 2008, Europe installed 357 MW, equivalent to almost 1 MW of offshore capacity being added every day (source: EWEA).[99]

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95 U.S. Department of the Interior. *Survey of Available Data on OCS Resources and Identification of Data Gaps*. OCS Report. MMS 2009-015, 2009.

96 http://www.bluewaterwind.com/de_overview.htm.

97 Jesmer, Graham, "Stage Set for Offshore Wind Energy in the U.S." *Renewable Energy World*, April 8, 2009.

98 http://www.capewind.org/news973.htm.

99 EWEA. *Seas of Change: Offshore Wind Energy*, February 2009, http://www.ewec2009.info/fileadmin/ewec2009_files/documents/Media_room/EWEA_FS_Offshore_FINAL_lr.PDF.

Current Trends

Onshore wind energy trends also affect the offshore industry. Some trends particular to the offshore industry are noted:

- Onshore wind turbine sizes have shown a steady increase over the past several years (see discussion in Onshore Wind section). This is significant since the trend for offshore wind has been for larger size turbines.
- The EU potential for offshore wind development is foreseen to be 20 to 40 GW through 2020. Back in 2003, EWEA published projections of 70 GW of offshore wind by 2020. This projection was foreseen as unrealistic and was revised in 2007 to 20 GW to 40 GW.[100]
- Due to the EU target of 20% renewables by 2020, offshore wind is foreseen to play a significant factor. Trends of past installations with projections for future growth are provided by EWEA and shown in Figure 45.

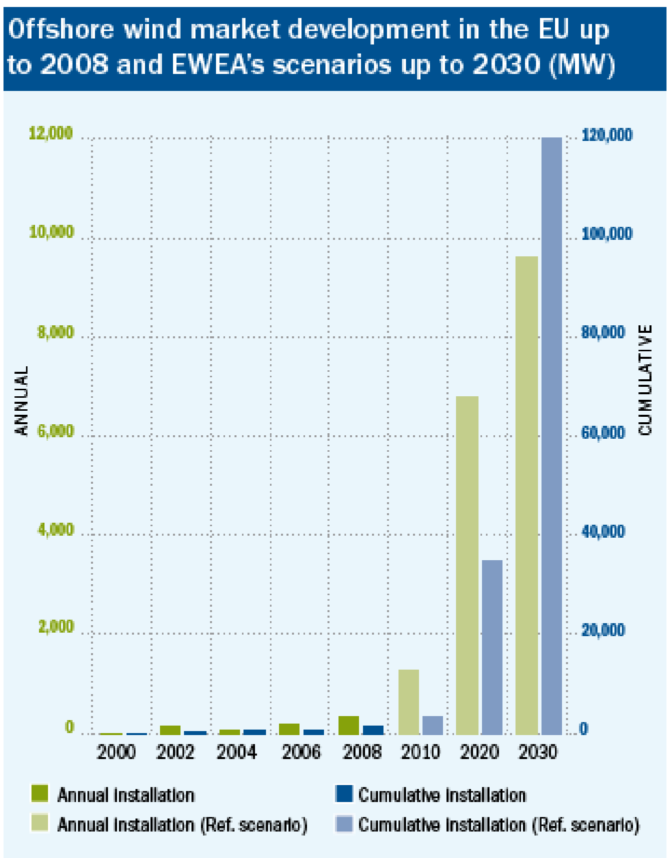

Figure 45. European offshore wind growth and projections

Source: EWEA, Seas of Change: Offshore Wind Energy.

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100 EWEA. *Delivering Offshore Wind Power in Europe*. December 2007.

With increased international growth of the offshore wind industry, some installations off the California coast should be realized within the next 20 years.

Cost Drivers

Primary cost drivers for offshore wind installations are as follows:

- Turbine cost.
- Reliability and maintenance.
- Permitting and site selection.
- Support structure.
- Grid connection and transmission costs.
- Development of technology of foundations or floatation.

These cost drivers are very similar to those for onshore wind. One key difference is for onshore, the turbine is approximately 75% of project costs, where for offshore the turbine is approximately 33% of project costs.

Current Costs

Both overnight and O&M costs of offshore wind installations have been estimated to be approximately twice that of onshore installations[101] (also from Black & Veatch, page 5-10).

Both the 2009 and 2018 Onshore Class 5 dollars have been doubled to obtain the necessary offshore wind project costs. For modeling purposes, it is estimated wind turbine installations will begin off the California coast in 2018.

Overnight Costs ($/kW):

	$2009	$2018
Average:	$3,980	$4,581
High:	$6,050	$6,964
Low:	$2,880	$3,315

101 Beurskens, L.W.M., M. de Noord, and H.J. de Vries. *Potentials and Costs for Renewable Electricity Generation*. Energy Research Centre of the Netherlands. ECN-C–03-006, February 2004.

Fixed O&M Costs ($/kW-yr):

	$2009	$2018
Average:	$27.40	$31.54
High:	$34.25	$39.42
Low:	$20.55	$23.65

Variable O&M ($/MWh):

	$2009	$2018
Average:	$11.00	$12.66
High:	$15.32	$17.63
Low:	$9.64	$11.10

One other thing to note is the capacity factor. Due to larger wind turbines for offshore applications (meaning higher towers) and lower wind turbulence, capacity factors will increase by 15% over onshore turbine estimates (Black & Veatch 2007). Capacity factor estimations are included in Figure 46.

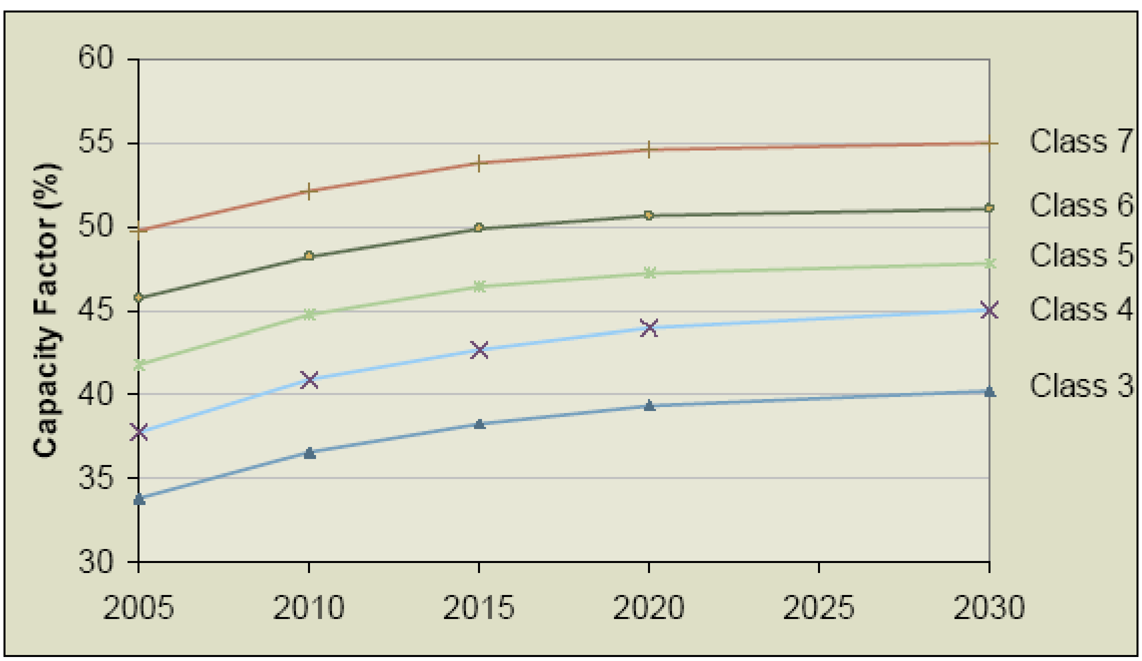

Figure 46. Offshore capacity factor by installed year

Source: O'Connell and Pletka, *20 Percent Wind Energy Penetration in the United States*.

Capacity factors for Class 5 offshore wind are estimated to vary between 42% and 48% with the average being 45%.

Expected Cost Trajectories

Primary cost trajectories are to include learning effects as more offshore wind projects are installed. Period 1 & 2 Learning Rates (20% and 10% respectively), defined in EIA's *Electricity Market Module*, were used to estimate cost reductions over time. It is estimated each learning rate will last five years. Therefore a total of 15% cost improvement will be realized between 2018 and 2029, based on increases in cumulative installed generation from 23 GW to 110 GW. This is a conservative estimate since onshore wind installations decreased in cost by 50% from 1982 to 1992.

3.7. Wave

3.7.1. Technology Overview

Wave energy extraction is complex, and many device designs have been proposed. For understanding the device technology, it is helpful introduce these in terms of their physical arrangements and energy conversion mechanisms.

- Distance from shore – Wave energy devices may convert wave power at the shoreline, near to the shore (defined as shallow water where the depth is less than one half of the wavelength) or offshore.
- Bottom mounted or floating – Wave energy devices may be either bottom-mounted or floating.

Wave energy devices can be classified by means of the type of displacement and reaction system employed. Various hydraulic or pneumatic power take off systems are used and in some cases the mechanical motion of the displacer is converted directly to electrical power (direct-drive) Four of the most well-known device concepts are introduced below and their principle of operation illustrated.

- Symmetrical point absorber – A bottom-mounted or floating structure that absorbs energy. The power take-off system may take a number of forms, depending on the configuration of displacers/reactors. The key characteristic of a point absorber is that it can absorb more energy than available within the devices width if the device is tuned (i.e., it is natural resonance frequency matches the incident wave frequency).
- Oscillating Water Column (OWC) –Nearshore or offshore, this is a partially submerged chamber with air trapped above a column of water. As waves enter and exit the chamber, the water column moves up and down and acts like a piston on the air, pushing it back and forth. The air is forced through a turbine/generator to produce electricity.
- Overtopping terminator – A floating reservoir structure with a ramp over which the waves topple and hydro turbines/generators through which the water returns to the sea.

- Attenuator – One form of the attenuator principle is a long floating structure that is orientated parallel to the direction of the waves. The structure is composed of multiple sections that rotate in pitch and yaw relative to each other. That motion is then converted to electricity using an electro-hydraulic power conversion machine.

Conceptual diagrams of these devices an included in the following figures (source: EPRI).

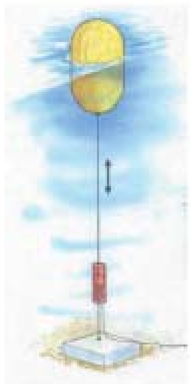

Figure 47. Point absorber
Source: EPRI, *Ocean Tidal and Wave Energy…*

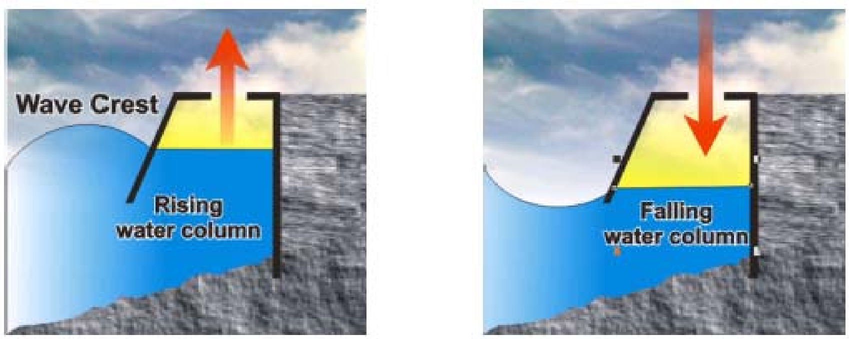

Figure 48. Oscillating water column
Source: EPRI, *Ocean Tidal and Wave Energy…*

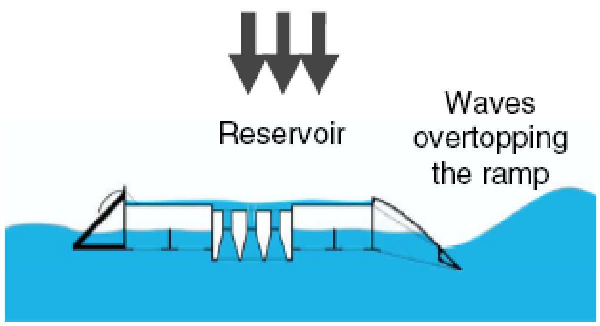

Figure 49. Overtopping
Source: EPRI, *Ocean Tidal and Wave Energy…*

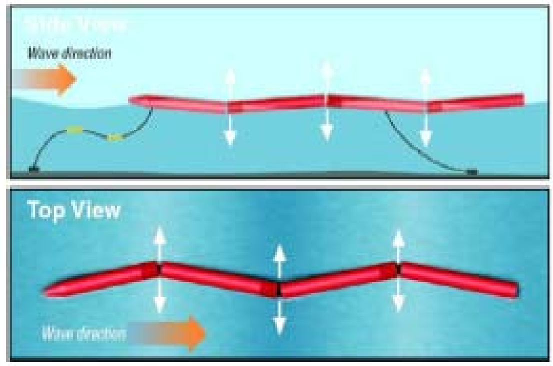

Figure 50. Attenuator

Source: EPRI, *Ocean Tidal and Wave Energy…*

3.7.2. Ocean Wave

Technical and Market Justification

Wave energy has been in existence for many years, although very few commercial developments are in place. Currently, worldwide installations total only 4 MW rated nameplate. There has recently been substantial interest, with over 25 countries involved in developing relevant conversion technologies for harnessing ocean renewable resources for electricity generation and/or other purposes. Also over the past two years there have been several companies submitting filings with the FERC for permits to install ocean wave energy systems in various locations along the California coast. These permits are for systems ranging in size from 1 to 5 MW to 100 MW.

Primary Commercial Embodiment

There are currently no commercial wave energy systems installed off the California coast.

Based on the recent FERC filings, it is hypothesized that by 2018 there will be some commercial wave energy systems installed off the West Coast of the United States. The FERC filings have been for systems from *up to 5 MW* to *up to 100 MW*. In reality, each of these companies that have submitted filings and will perform some installations will perform more detailed evaluations of the site, begin installing ocean wave units, evaluate their performance, and then add more units to the plants based on their evaluations of performance and projected costs/benefits. A 40 MW typical plant size is foreseen as average based on the range of FERC filings.

Cost Drivers

Market and Industry Changes

There have been no market and industry changes since August 2007 that have materially affected the costs of wave energy systems.

Current Trends

Based on a review of several FERC filings, it is foreseen that a few wave energy manufacturers will install demonstration projects to prove out their system and then add to the capacity based on their success. The filings show modularity with the systems, which allow adding onto capacity with multiple units.

Cost Drivers

Primary cost drivers for this technology are as follows:[102]

- Device structure – Required to house the wave energy turbine and generator.
- Mechanical and electrical plant – Shore-based power station for the unit.
- Transportation and installation – Moving equipment to the shore and shipping to the off-shore device structure.
- Construction management and permitting – Administrative costs.
- Electrical transmission – Undersea cables.
- Variable O&M – Cost of spares and repair costs (replacement parts and removal, replacement and refurbishment of parts).
- Fixed O&M – Operational costs (maintenance crews and vessels to enable repairs).

Current Costs

The best cost information was found from a report published by the Energy Technology Support Unit (ETSU) of the Association for Educational Assessment (AEA) Europe.[102] The report outlines the result of a European cost model developed in the early 1990s and refined in the late 1990s. It gives cost data and capacity factors for several competing wave energy technologies in 1999 British pounds.

British pounds (1999) were converted to 1999 United States' dollars through historical exchange rates.

Equation 17: 1999 British pound to 1999 U.S. dollar Conversion

1999 U.S. dollar = 1.61 x 1999 British pound

United States' dollars (1999) were converted to present and future dollars strictly through inflation estimates. A summary of the costs obtained and the costs calculated are included in Table 25.

102 Thorpe, Tom. *A Brief Review of Wave Energy*. AEA Technology. ETSU-R120, May 1999.

Table 25. Ocean wave energy cost data

Device	Rated Capacity	Capacity Factor	Estimated Cost (£)	Estimated Cost per Unit (£/kW)	Estimated Cost per Unit ($/kW)	Fixed O&M per Unit (£/kW)	Fixed O&M per Unit ($/kW)	Variable O&M per Unit (£/MWh)	Variable O&M per Unit ($/MWh)
Limpet	1 MW	0.206	£1,160,000	£1,160	$1,868	£13	$21	£4	$7
Limpet II	1 MW	0.26	£1,400,000	£1,400	$2,254	£17	$27	£6	$9
Ospray	20 MW	0.26	£26,300,000	£1,315	$2,117	£19	$31	£7	$11
Duck	2 GW	0.3	£2,400,000,000	£1,200	$1,932	£21	$34	£7	$11
Averages		0.26		1999 cost	$2,043		$28		$9
				2018 cost	$2,978		$41		$14
				2009 cost	$2,587		$36		$12
Low		0.21		1999 cost	$1,868		$21		$7
				2018 cost	$2,723		$31		$10
				2009 cost	$2,365		$27		$9
High		0.30		1999 cost	$2,254		$34		$11
				2018 cost	$3,286		$50		$17
				2009 cost	$2,855		$43		$14

Source: Thorpe, T.W.

Expected Cost Trajectories

Learning effects from ocean wave technology are expected be modest since cumulative generation is not expected to be at a high enough level to take advantage of economies of scale.

3.8. Integrated Gasification Combined-Cycle

3.8.1. Technology Overview

There are several major IGCC process technologies available for power generation. The main suppliers of gasifier technology are Shell, GE, Siemens, and ConocoPhillips. The research team did not focus on one of these process technologies to avoid excluding possible viable options for the future. Therefore the selected IGCC technology for this study is based on the current worldwide practice for coal-fueled IGCC technology at a scale of 300 MW. This results in the selection of the oxygen-blown entrained flow gasifier process technology.

Air-blown gasification technology is available, but since it has not been applied outside of Japan, it is not considered as a primary commercial embodiment of the IGCC technology. This process does not require an air separation unit; however, the syngas contains a lot of nitrogen resulting in much larger dimensions of equipment than oxygen-blown gasification.

Figure 51 shows a typical oxygen-blown IGCC process schematic, and Figure 52 shows an aerial photo of an actual installation.

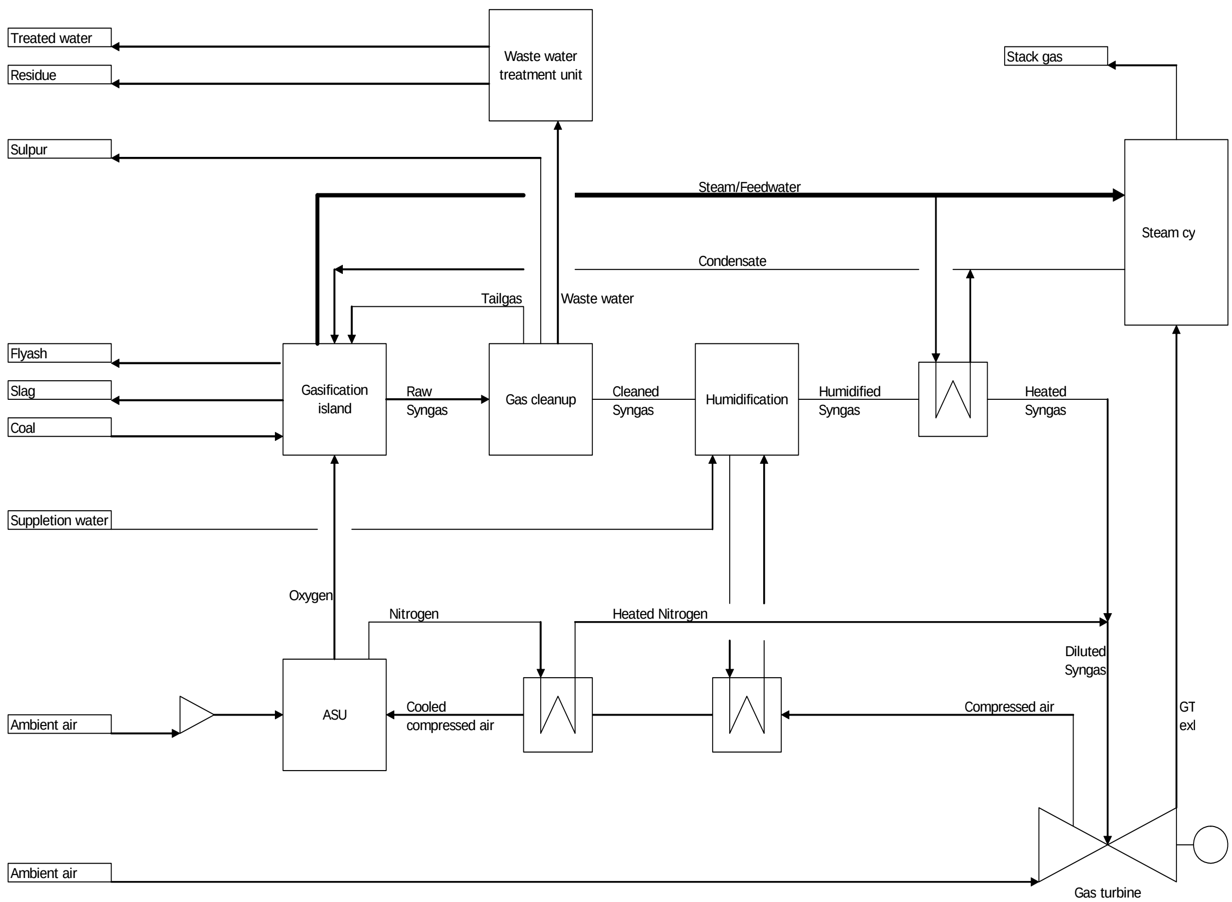

Figure 51. Typical oxygen blown IGCC process

Source: KEMA

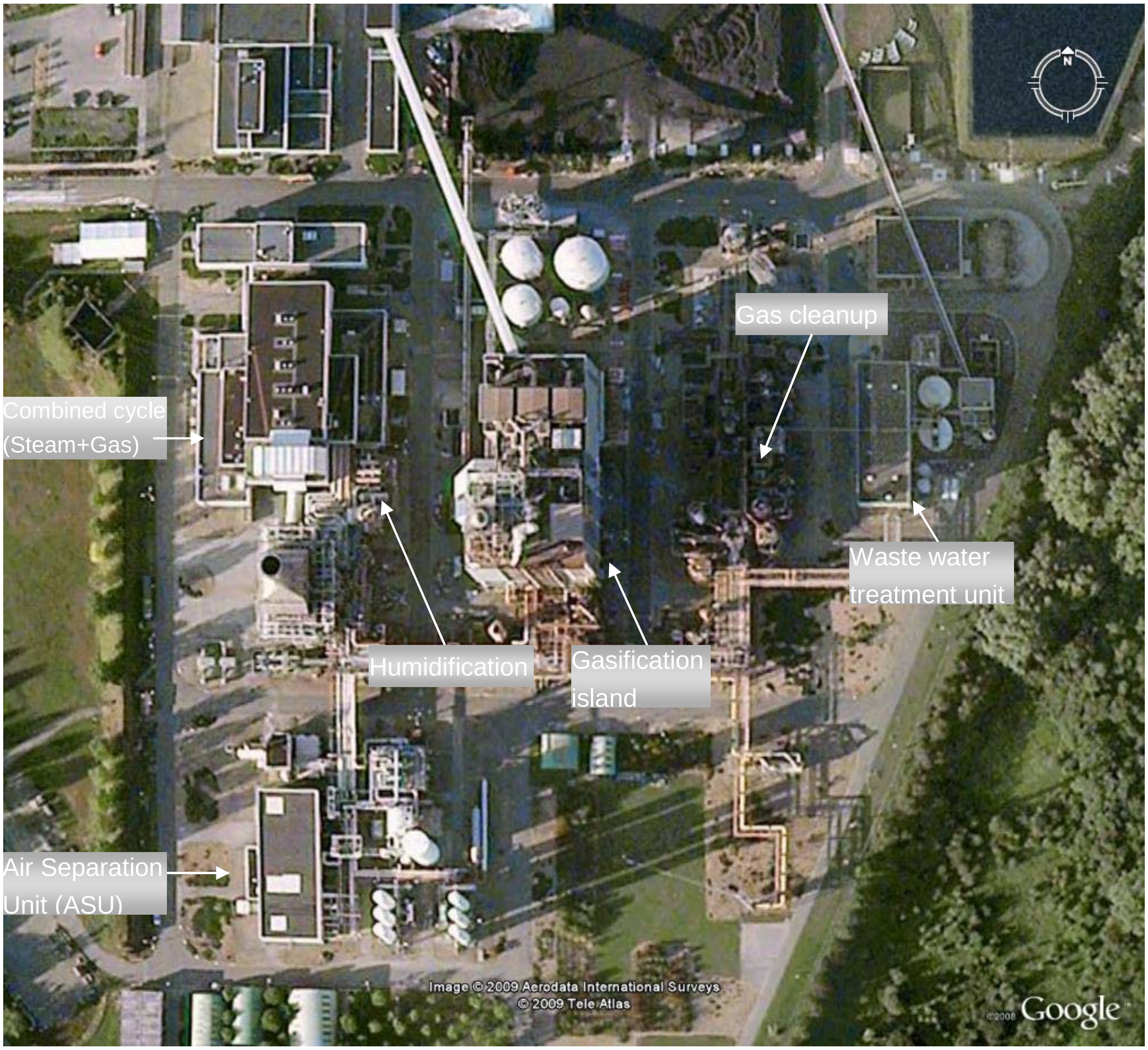

Figure 52. Actual installation (Buggenum, The Netherlands) with typical technological components indicated

Source: Google Earth, modified by KEMA

The basic principle of IGCC is the gasification (partial oxidation) of pulverized coal with oxygen and steam to produce a syngas, which is combusted in a gas turbine. The oxygen is supplied by an air separation unit which separates ambient air into oxygen and nitrogen. The air can be delivered by the compressor of the gas turbine (full air-side integration) or by a separate compressor (no air-side integration). Air-side integration will lead to higher plant efficiency but also to more complex power plant operations. Current state-of-the-art is partial air-side integration.

In the gasification island, coal (either supplied in slurry or in powder form) is gasified in the reactor into raw gas. Apart from the raw gas also fly ash and slag are formed. The raw gas contains:

- Combustible components CO and H2.
- Incombustible harmless components H2O, N2, Ar.
- Greenhouse gas CO_2.
- Traces of environmentally and/or technically harmful gaseous components:
  - Sulphur: H2S and COS.
  - Halogens: HCl and HF.
  - Nitrogen: NH3, HCN.
  - Traces of alkali and heavy metals (such as mercury).

The raw gas is purified in the gas cleanup, that is removal of fly ash (via cyclone, filter, and/or wet scrubbing), heavy metals, halogen, nitrous compounds, alkali (wet scrubbing), and sulphur (absorption). During this process waste water and some tail gas are produced. The tail gas is recycled back into the gasification island while the waste water is cleaned in the waste water treatment plant. During this process clean distillate and residue are produced. The distillate is reused in the power plant.

The cleaned syngas is moisturized and diluted with nitrogen to achieve a lower heating value. This contributes to lower NOx-emissions. Also the heat rate is improved marginally. To improve the heat rate further the humid syngas is heated by feedwater from the steam circuit between gasification island and steam cycle.

The diluted syngas is combusted under pressure in the gas turbine using ambient air pressurized by the gas turbine's compressor. The hot combustion gases drive the gas turbine's expander, providing electric power to drive compressor and generator. The exhaust gases are lead into the steam cycle where steam is produced in the waste heat boiler and is expanded in the steam turbine installation, producing electricity.

3.8.2. IGCC Without Carbon Capture (Single or Multiple 300 MW Trains)

Technical and Market Justification

Coal-IGCC is a very promising new clean-coal technology, especially because it is well- suited for CO_2 capture. As illustrated by an increasing trend in announcements of new United States' gasification projects, the United States' market is aware of this potential applicability of coal-IGCC for future power generation. The entities that are considering implementing IGCC projects include some major energy industry players such as AEP and Duke Energy (formerly Cinergy). In addition, numerous smaller companies are pursuing gasification projects using state and federal grants. The more advanced, publicly discussed IGCC projects are shown in Table 26. In total, based on information from public announcements, 50 projects have been identified for United States operation beyond 2010.

Table 26. Gasification-based power plant projects under consideration in the United States beyond 2010

Project Name/Lead	Location	Feedstock	CT Fuel	Net (MWe)
Orlando Gasification Project*/Southern Co., OUC	Orlando, FL	coal	syngas	285
Lima Energy IGCC/Global Energy	Lima, O	coal/ petcoke	syngas	540 SNG H_2
Cash Creek IGCC Plant/GE, MDL Holdings	Henderson County, KY	coal	syngas	630
Lockwood IGCC Plant/Hunton Energy, Cogentrix Energy Inc.	Sugar Land, TX	petcoke	syngas	1200
Mesaba/Excelsior Energy	Holman, MN	coal/ petcoke	syngas	600
Carson H_2 Power Project/BP, Edison Mission Group	Carson, CA	petcoke	H_2	500
FutureGen/FutureGen Alliance	Illinois or Texas	coal	H_2	275
Mountaineer Plant/AEP	New Haven, WV	coal	syngas	630
Pacific Mountain Energy Center/Energy Northwest	Port Kalama, WA	coal/ petcoke	syngas	680
Taylorville Energy Center IGCC/CCG LLC	Taylorville, IL	coal	syngas	630
Huntley IGCC Project/NRG Energy	Tonawanda, NY	coal	syngas	680
Tampa Electric, Unit 2	Polk County, FL	coal	syngas	630
Wallula Energy Resource Center/Wallula Resource Recovery LLC	Wallula, WA	coal	syngas	600-700
Xcel Energy	Colorado	coal	syngas	300-350
TXU Corp.	Colorado City, TX	coal	syngas	630
TXU Corp.	Henderson, TX	coal	syngas	630
Clean Hydrogen Power Generation Project/Southern California Edison	California	coal	H_2	600
Indian River IGCC Project/NRG Energy	Millsboro, DE	coal	syngas	630
Edwardsport IGCC Project/Duke Energy	Edwardsport, IN	coal	syngas	630
Great Bend/AEP	Meigs County, OH	coal	syngas	630
IGCC Demonstration Plant/Wyoming Infrastructure Authority, Pacific Corp	Wyoming	coal	syngas	TBD
Lower Columbia Clean Energy Center/ Summit Power Group	Clatskanie, OR	petcoke/ coal	syngas	520
Mississippi Power	Kemper County, MS	coal	syngas	600
NRG Energy	Texas	coal	syngas	630
Steelhead Energy/Madison Power	Williamson County, IL	coal	syngas	620 SNG

Source: U.S. DOE, NETL, *Gasification World Database 2007*.

Primary Commercial Embodiment

Currently, no new gasification plants are projected to come on-line in the North American region from 2008 to 2010. This continues the trend from 2005 to 2007 where no new plants were started in the United States and only one plant, the Long Lake Plant, began operations in

Alberta, Canada. This absence of new United States capacity additions from 2005 to 2010 is understandable given that these plants would have had to be committed to during the late 1990s and early 2000s. In those years the natural gas prices were low, resources for industrial needs and transportation fuels were seemingly abundant, and the results from demonstrations of new generation gasification technologies (e.g., the Polk and Wabash IGCC plants) were not yet fully known. However, with expanded demand for power plants, concerns over the availability and prices of oil and gas, and increased consensus regarding the needs for deployment of technologies providing for environmental protection, gasification-based projects are increasingly viewed as a technology option for future progress.[103]

The commercial applicability of coal-fueled IGCC is demonstrated by approximately 18 IGCC projects throughout the world. One of these projects was the coal/petcoke-based Cool Water IGCC plant, which has been decommissioned. Of the six currently operating coal IGCC plants, four are commercial-scale, entrained flow gasification demonstration projects (ranging in capacity from 250 to 300 MW) and are located in Florida, Indiana, The Netherlands, and Spain.[104] This information shows that entrained flow gasification technology has been selected by all six companies. As feedstock, bituminous coal is the main choice, followed by a blend of petcoke. The Southern Company/OUC project is based upon 100% Power River Basin coal but is a commercial demonstration project for a new gasification technology and the demonstration will not be complete until 2015. NRG Energy reports using a fuel supply of primarily coal but could include up to 20% petcoke and 5% biomass.

Current trends suggest that the IGCC of the future will contain much of what is seen now, with entrained gasification retaining its position as the most common system. The gas turbines will be based on the natural gas-fired versions that will have been deployed a few years earlier. Hydrogen technology will probably be the safe option at that time. The larger capacity of the H-class gas turbines will provide an economy of scale, helping to reduce the specific capital cost of IGCC. If, additionally, gasifier unit sizes have been successfully increased, and it becomes possible for a one-on-one gasifier/gas turbine combination to be used, this will provide further cost savings due to scale. Steam conditions in the steam cycle could then be raised to ultra-supercritical, which will give further (modest) efficiency benefit.

Although the Coolwater IGCC demonstration plant built in California in the 1980s was the world's first commercial-scale IGCC demonstration plant, only one gasification project is currently under consideration in the state, a Clean Hydrogen project as shown in Table 26.

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103 U.S. Department of Energy. Office of Fossil Energy. National Energy Technology Laboratory. *Gasification World Database 2007*, October 2007. <http://www.netl.doe.gov/technologies/coalpower/gasification/database/database.html>.

104 Black & Veatch. *Clean Coal Technology Selection Study Final Report January 2007*. Black & Veatch, 2007.

Cost Drivers

Market and Industry Changes

Construction costs for power plants have escalated at an extraordinary rate since the beginning of this decade. Most recent change is the current credit crunch that will affect the demand and supply equilibrium in market. The effects on the cost price development for coal-fueled IGCC power plants were analyzed.

Current Trends

The research team included the following trends in the cost analysis:

- Construction material costs.
- Equipment costs.
- Labor costs.
- Learning effects.

Data from the U.S. Bureau of Reclamation were used to assess trends in construction costs. These general construction cost trends were developed to track construction relevant to power generation project costs. This data was also compared with the *Gasification World Database 2007* report, which shows that cost of original equipment and installation has increased as much as 20% to 30% since 1998.[105] Figure 53 shows power plant construction costs and main components. The various cost indexes in the figure all consist of two elements: contractor labor and equipment costs and contractor supplied materials and equipment. A dramatic increase in costs is evident at the end of 2008, corresponding to the beginning of the credit crunch.

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105 U.S. Department of Energy. Office of Fossil Energy. National Energy Technology Laboratory. *Gasification World Database 2007*, October 2007. <http://www.netl.doe.gov/technologies/coalpower/gasification/database/database.html>.

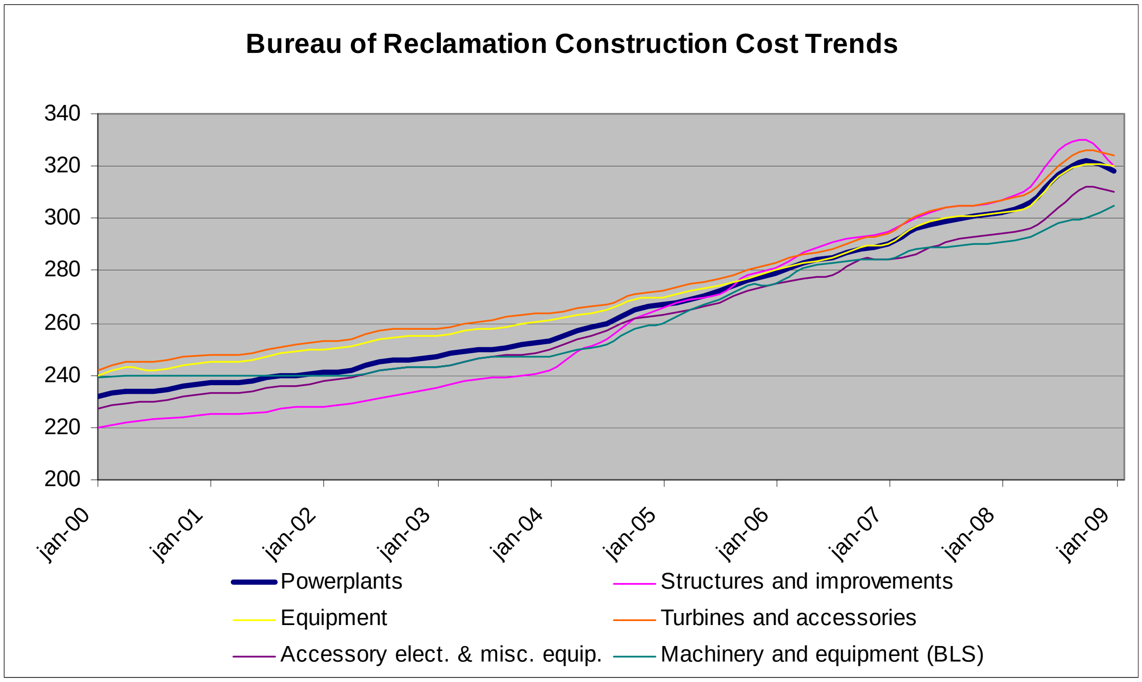

Figure 53. Bureau of Reclamation construction cost trends

Source: KEMA, based on U.S. Department of the Interior, Bureau of Reclamation data, website http://www.usbr.gov/pmts/estimate/cost_trend.htm

Cost Drivers

The primary cost drivers for the cost of electricity from IGCC plants are:

- Government incentives – Many government incentives influence the cost of generating electricity. Some incentives have a direct and clear influence on the cost of building or operating a power plant, such as an investment tax credit. Others have less direct effects that are difficult to measure, such as parts of the tax code that influence the cost of producing fossil fuel.[106]
- Capital and financing costs – Focusing on construction cost components and trends. The cost components that were analyzed were EPC costs, owner's costs, and capitalized financing charges for the California/United States situation.[107]
- Operating costs (e.g., fuel costs) – Broken down into fuel costs and non-fuel O&M costs. Coal typically accounts for 20% to 25% of the cost of energy from an IGCC or PC power plant. O&M costs include labor, maintenance material, administrative support,

106 Kaplan, Stan, *Power Plants: Characteristics and Costs*. Congressional Research Service. National Council on Science and the Environment, Washington DC, 2008.

107 Black & Veatch. *Clean Coal Technology Selection Study Final Report January 2007*. Black & Veatch, 2007.

consumables, and waste disposal and typically account for 20% of the cost of energy from an IGCC power plant.[108]

- Air emissions controls for coal and natural gas plants – Regulations that limit air emissions from fossil-fueled power plants can impose two types of costs: costs of installing and operating control equipment, and costs of allowances that permit plants to emit pollutants.[109]
- Redundancy / availability – To achieve a +85% net capacity factor with current gasification technologies, it is generally believed that redundant gasifier capacity is required, which increases the cost of IGCC facilities. However, it is the research team's assessment that this can be reached with one train, thus not requiring a spare gasifier.

Current Costs

Gross capacities for coal-fired IGCC plants ranged from 300 MW low and average cases to a 600 MW high case, both cases due to the commercial embodiment of the technology, with the 600 MW case being developed with multiple gasifier trains and turbines, and the 300 MW case being developed as a single-train gasifier setup.

Net capacity factors were modeled between a range of 70-90%, with 80% being the average case, primarily due to the expected on-stream performance of the gasifier unit. Currently, the longest continuous gasifier operating duration is approximately 2,700 hours. Current gasification technology performance trends indicate capacity factors of 70-90% to be current state-of-the-art.

Instant costs were modeled between a range of $1,700/kW and $2,800/kW, with an average instant cost of $2,250/kW. The range extremes on the low cost side are due to options for repowering existing gas turbine units to a gasification combined-cycle configuration, while the high cost scenario represents a higher level of design standard to promote additional in-service reliability.

Heat rates and fixed/variable O&M costs reflect the current technology base, using an F-class turbine heat rate coupled with the gasifier parasitic power load, and the operational processing cost of the syngas from the gasifier trains.

Overall fuel costs, in this case the raw coal feedstock input, were modeled using 11,700 Btu/lb Uiinta Basin coal sources in Colorado and Utah, a primary source of western coal supply for California, and plants that feed electricity into California.

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108 Breeze, Paul, "The Cost of Power Generation: The Current and Future Competitiveness of Renewable and Traditional Technologies." *Business Insights Ltd*., 2008. http://www.globalbusinessinsights.com/content/rben0202m.PDF.

109 Rosenberg, William G., Dwight C. Alpern, and Michael R. Walker. "Deploying IGCC Technology in This Decade With 3 Party Covenant Financing: Volume II." ENRP Discussion Paper 2004-07: Belfer Center for Science and International Affairs, Kennedy School of Government, Harvard University, Cambridge, MA, July 2004.

Expected Cost Trajectories

Experience curves for advanced fossil-fuel technologies are limited. Those available, some of them old, indicate both cost increases and cost reductions. In this study, the research team assumed a learning rate of 5%. This implies a 5% cost reduction per cumulative doubling of installed capacity.

3.8.3. Carbon Capture and Sequestration

As climate change policy and carbon-based regulation become more prevalent in both the United States and California, solid-fuel combustion technologies will be driven toward integrated gasification technologies. Gasification technologies provide the ability through the chemical processes of gasification to separate carbon dioxide as a separate off-gas stream for potential capture and sequestration.[110]

Manufacturers involved in integrated gasification combined-cycle technologies are pursuing pre-combustion removal of carbon dioxide through the gasifier, with at least a 90% effective carbon dioxide capture rate, with research efforts ongoing.[111]

Currently, research into carbon capture and sequestration (CCS) projects are being spearheaded by oil and gas companies, such as Shell, Total, and Chevron, where the technology base used is similar to that used for carbon dioxide injection for enhanced oil and gas recovery techniques. However, a number of obstacles for utility-scale adoption of these technologies remain, including the specific application of oil/gas carbon dioxide sequestration technologies to reliably and securely sequester carbon dioxide emissions for centuries. Commercial-scale research demonstration projects have begun, totaling an estimated $20 billion in worldwide spending.

A recent McKinsey study shows that carbon prices between $45 and $64 per metric ton are needed to make CCS projects viable, compared to a current European Union price of $10-12 per metric ton.[112]

Market forces for carbon emissions reductions and carbon prices will play a key role in determining the cost trajectory and commercial development potential for CCS over the next 20 years. Currently, the technology base for utility-scale CCS applications is in the early demonstration phase. For example, China is proceeding with its GreenGen project, a 200 MW integrated gasification combined-cycle unit located in the city of Tianjin, but carbon injection and sequestration is not anticipated until approximately 2020.[113]

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110 U.S. Department of Energy, National Energy Technology Laboratory. *Gasification World Database 2007.*

111 Siemens Westinghouse, "Improving IGCC Flexibility Through Gas Turbine Enhancements." Gasification Technologies Conference 2004, October 2004.

112 Scott, Mark, "Is 2009 the Year for Carbon, Capture, Storage?"*Business Week, Green Business*, February 16, 2009.

113 Forbes, Sarah, "Hearing before the U.S. House of Representatives Science and Technology Committee on Energy and the Environment: 'FutureGen and the Department of Energy's Advanced Coal

The FutureGen project, considered a leading project for United States-based CCS technology demonstration, was scrapped in 2008 after the cost of the project ballooned to $1.8 billion. Alstom estimates today that such a carbon capture plant would cost $1 billion to produce.

McKinsey also presents that CCS technology will not become mature until sometime near 2030, citing numerous concerns from cost-competitiveness with carbon prices to minimal learning curves for applying the technology.[114] In addition, questions regarding the efficacy of storage and the implementation of projects after the initial commercial demonstration phase are key unresolved issues. [115]

Based on the lack of commercially demonstrated utility-scale CCS projects currently in operation, the anticipated start of those demonstration projects on or near 2015, and the expected 10-15 year time horizon to scale the technology from demonstration to full commercial embodiment, the research team did not include CCS technology in the cost of generation analysis. The research team notes that several factors may change this determination over the next few years, namely:

- Government/policy mandates – Supporting investment, development, and rapid commercialization of CCS technologies on an accelerated basis.
- Increases in carbon market price value – To the extent that a currently anticipated $40-65/metric ton market value is needed to support breakeven financial performance of today's CCS technologies
- Global changes in CCS technology base – Current interest in the United States and in the European Union is significant and may produce breakthroughs in CCS technology, which could alter the cost trajectories of CCS enough to warrant inclusion in a commercially viable cost of generation analysis.

The research team recommends that the CCS technologies be evaluated for inclusion in future cost of generation studies once demonstration projects provide enough data for commercial estimates to be reliable.

Programs'." U.S House of Representatives. Committee on Science and Technology. Subcommittee on Energy & Environment, March 11, 2009.

114 The Economist. "Trouble in Store." *Economist.com,* March 5, 2009.

115 McKinsey & Company. "Carbon Capture & Storage: Assessing the Economics," McKinsey & Company, September 2008.

3.9. Advanced Nuclear

3.9.1. Technology Overview

The nuclear power industry in the United States is attempting to stage a comeback. With natural gas prices volatile and people anxious about climate change, the nuclear power industry is marketing its technology as a way to meet the nation's growing energy needs without emitting more greenhouse gases. Over the next two years, the U.S. Nuclear Regulatory Commission (NRC) expects applications to build as many as 27 new nuclear reactors. Here are some technology statistics:

- Approximately 435 commercial nuclear power reactors currently operate in 30 countries, supplying 370,000 MWe of total capacity and 16% of the world's baseload electric power.[116]
- The United States has 104 nuclear reactors operating in 31 states and providing almost 20% of its electricity.
- In the United States, there have been 17 license applications to build 26 new nuclear reactors since mid 2007, following several regulatory initiatives preparing the way for new orders.
- Life extension of nuclear reactors is progressing to 60-year life spans across the nuclear operating fleet.
- Ownership and operation of nuclear reactors have become more concentrated over the last decade.

In contrast to the 20% of electricity supplied by nuclear plants in the United States, 75% of France's electricity is supplied by nuclear plants. There has been no new order for a nuclear power plant in the United States since the 1970s, and no new plant has been completed in the United States since 1996. California has had a moratorium on issuing land-use permits for new nuclear plants until the Energy Commission finds that there is an approved means for the permanent disposal of high-level radioactive waste. United States' nuclear facilities have successfully boosted output in recent years by increasing usage rates from historical values of 70% to over 90%. Still, proponents of nuclear energy estimate that the United States will need 30 new nuclear plants by 2025 to keep pace with increasing electricity use.[117] However, opponents of nuclear power point to the high construction costs of the next generation reactors and difficulty in financing them in today's credit constrained markets.

A number of major risk factors are present in the quest for a nuclear comeback, including the largest risk of all, nuclear plant construction costs. The ability to estimate new plant

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116 http://www.aboutnuclear.net/English/Nuclear_Power_in_the_World.html.

117 Mufson, Steven. "Nuclear Power Primed for Comeback - Demand, Subsidies Spur U.S. Utilities." *The Washington Post*, October 8, 2007; A01.

construction costs when very few nuclear plants have been built since the Three Mile Island and Chernobyl accidents have widened the spread of estimated nuclear construction costs over the past decade and created a great deal of uncertainty in both the utility industry and the financing markets. A recent update to a MIT study found in 2008 that the cost spread of instant costs for recent, similar nuclear plant projects in the United States ranged from $3,500 - $4,800/kW (2007 dollars), which is a very large spread in costs.[118] Difficulty in estimating nuclear plant costs with precision and certainty is due to these factors:

- Lack of available reference plant data – Very few reactors have been built in the world recently and none in the United States.
- Historical experience – Past estimates of nuclear plant installed costs have not always been found true when actual construction is completed. A recent evaluation of predicted versus actual costs found that costs estimates have severely underpredicted actual costs.

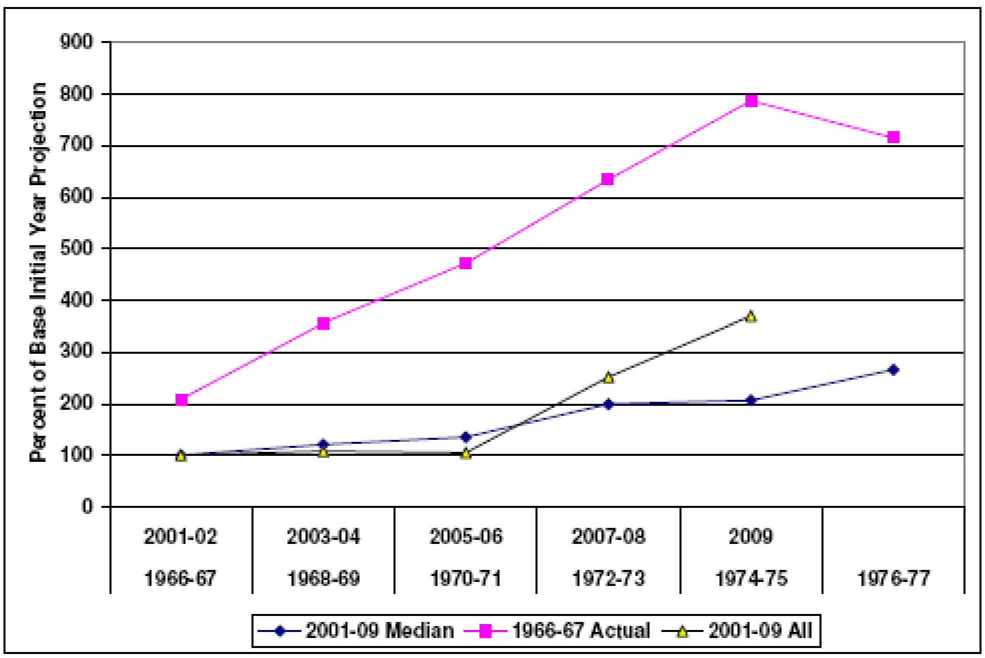

Figure 54. Actual vs. Predicted Nuclear Reactor Capital Costs

Source: Mark Cooper. "The Economics of Nuclear Reactors: Renaissance or Relapse." Institute for Energy and the Environment, Vermont Law School, June 2009.

- Supply Chain Issues – Considerable uncertainty still exists around the capability of the nuclear supply chain to deliver the highly engineered, ultra-high-quality vessels, fabrications, and materials needed to support a nuclear construction revival. For

118 Du, Yangbo and John E. Parsons. *Update on the Cost of Nuclear Power*. MIT Center for Energy and Environmental Policy Research, May 2009

instance, the number of ASME "N" stamp nuclear fabricators has dropped from 400 suppliers 20 years ago to 80 today. In addition, currently only two worldwide suppliers exist to supply reactor vessels – Japan Steel Works and Creusot Forge.[119] The U.S. Department of Energy, through its NP2010 program, performed a detailed manufacturing resource assessment in 2005 and found that out of 22 major material categories, five would require extra leadtime, with the two largest impact supply chain issues being manufacture of the reactor vessel large ring forgings (two worldwide suppliers) and main plant digital control systems and simulators, both requiring an extra 2-3 year lead time from procurement to delivery.[120]

- Specialized Nuclear Labor Costs and Availability – The NP2010 program assessment stated that the specialized trades needed for nuclear construction, especially boilermakers, pipefitters, electricians, and ironworkers, are expected to be in short supply and will require mitigation steps to avoid construction delays due to labor.[121] The shortage of skilled trade construction labor has been a national problem for the past decade, and without mitigating steps for flexibility in attracting or retaining workers, delays in construction and/or cost increases could result. In addition, the need for nuclear-certified quality control programs and properly trained staff to NRC quality requirements is essential.
- Material Cost Escalation – Over the past decade, material costs used for all electricity generation construction have escalated far in excess of the inflation rate, and even more so for materials used in nuclear construction. While the recent economic recession has significantly dampened the increases, uncertainty exists as to whether the cost escalation trends of the last decade will continue.

119 Harding, James. *Overnight Costs of New Nuclear Reactors.* Green Energy Coalition, EB-2007-0707, August 2008.

120 D'Olier, Robert., et.al.. *DOE NP2010 Construction Infrastructure Assessment*. U.S. Department of Energy, October 2005.

121 Ibid.

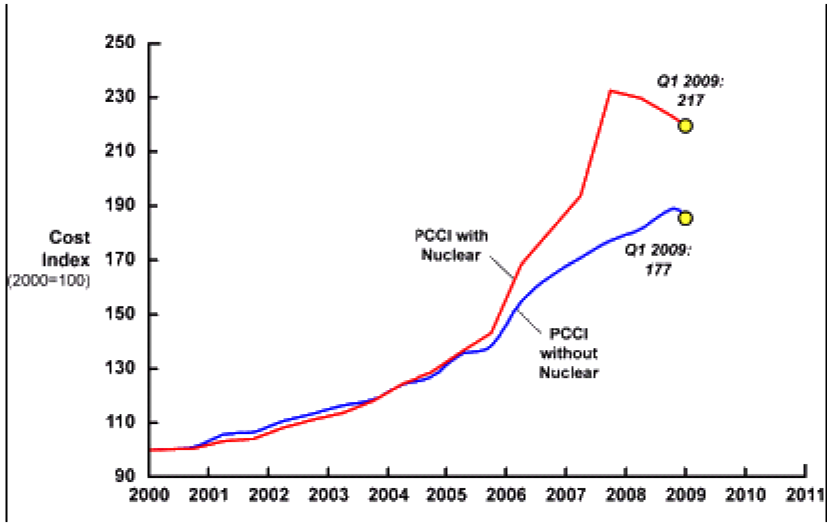

Figure 55: Power Capital Cost Index – Nuclear and Non-Nuclear Construction

Source: IHS – CERA. *IHS CERA Power Capital Costs Index Shows Construction Costs Falling for All Types of New Power Plants*. June 23, 2009.

Because so much of the overall cost and risk of nuclear power is tied up in the initial construction cost of the plant, financial risk and uncertainty loom as significant risks to the widespread adoption of nuclear power. Many utilities are reluctant to commit to nuclear construction programs because of the financial risk to a utilities' balance sheet and financial stability. Today, ratings agencies such as Standard & Poor's and Moody's have issued cautions to utilities seeking to embark on nuclear construction programs, stating that utilities need to plan for additional liquidity in their balance sheets to cover the uncertainties of ultimate built plant cost and the potential for underestimation of regulatory treatment and rate recovery from public utility commissions.[122]

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122 Moody's Corporate Finance. *New Nuclear Generating Capacity: Potential Credit Implications for U.S. Investor Owned Utilities*. Moody's Corporate Finance, May 2008.

New Commercial Reactor Designs

The standardization in the design of nuclear power reactors evolved over the past several decades. The original types of reactors consisting of the boiling water reactors (BWR) and the pressurized water reactors (PWR) technologies gave way to the latest designs introduced by the major United States' manufacturers such as the Westinghouse and the General Electric-Hitachi joint venture consortium. The Westinghouse AP-1000 design is based on the PWR reactor type, and it is the most popular in the United States and China. General Electric's Advanced Boiling Water Reactor (ABWR) design is based on the original BWR technology and is gaining the momentum in the United States and abroad, with units having been built in Japan.

Advanced Nuclear Power Reactors

Newer advanced reactors have:[123]

- Simpler designs, which reduce capital cost. Safety systems are advanced and reduce the potential for reactor scrams (a defined nuclear emergency where the nuclear reactor is scrambled or goes through an emergency shutdown).
- A standardized, modular design for each type to expedite licensing, reduce capital cost, and reduce construction time.
- Fuel-cycle designs to reduce nuclear proliferation risks.
- A higher availability and longer operating life – OEMs have typically quoted 60 years.

Typical reactor designs consist of the PWR, BWR, PHWR (pressurized heavy water reactor), HGTR (high temperature gas-cooled reactor), PBMR (pebble bed modular reactor) and a new 4S technology emphasizing the super safe, small, and simple reactor design.

The Economics of Nuclear Power

- Nuclear plants' largest costs are associated with their upfront capital costs for materials and construction. The upfront capital costs of nuclear power are the highest cost driver behind current nuclear cost economics and the current imbalance between nuclear power and fossil-fuel technologies.
- Fuel costs for nuclear plants account only for approximately 10% of total generating costs, making nuclear power plants relatively immune from uranium fuel-price variations.[124]
- True lifecycle costs of nuclear power must take into account the costs of site decommissioning and nuclear spent-fuel waste disposal. Site decommissioning and the

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123 World Nuclear Association. *Advanced Nuclear Power Reactors.* http://www.world-nuclear.org/info/inf08.html. Retrieved 5/15/2009.

124 Tolley,George, et.al., "The Economic Future of Nuclear Power," University of Chicago, August 2004.

issue of nuclear waste disposal are two of the major barriers to developing additional nuclear power facilities in the United States.[125]

Nuclear reactor manufacturers have stated that they could cut costs and reduce licensing delays by using standard designs, similar to France's standardized reactor approach, rather than tailoring plants to each customer. The new designs that are in the pre-certification process at the NRC reflect this new approach by the Westinghouse and other major manufacturers in the United States and the world.

3.9.2. WESTINGHOUSE - AP1000

Technical and Market Justification

The Westinghouse AP 1000 was selected for cost analysis due to its worldwide acceptance. Westinghouse Corporation was selected to supply new nuclear plants in China and other countries. The most recent announcements from China regarding the plans to purchase 100 AP1000 plants over the next 25 years are an indication of an international acceptance of this design. Furthermore, the AP1000 has been identified as the technology of choice for no less than 12 new projected plants in the United States.

It is the judgment of the research team that the AP1000 is the best balanced choice for modeling Gen III nuclear reactor technology. This judgment is based several factors, the first being the design competition to supply the Chinese government with advanced nuclear power technology. The Chinese competition, begun in 2003 against a global array of nuclear industry companies, resulted in the selection of the AP1000 in the largest energy cooperation project between China and the United States. The first reactor, Sanmen Nuclear Power Station, began construction in early 2009 and is expected to achieve commercial operation in 2013.[126] The second factor is the current certification of the AP1000 by the NRC, allowing construction in the United States and California. A third factor is the generational differences in technology and safety systems included in the AP1000, while the Toshiba-GE ABWR technology is of earlier development, having been certified in 1997.

The DOE in its NP2010 study showed that three primary embodiments of Gen III nuclear technology are:[127]

- General Electric (GE): Economic Simplified Boiling Water Reactor (ESBWR)
- Toshiba Version – GE Design: Advanced Boiling Water Reactor (ABWR)
- Westinghouse Design: Advanced Pressurized Water Reactor (AP1000)

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125 Beckjord, Eric, et.al. *The Future of Nuclear Power*. Massachusetts Institute of Technology, 2003

126 http://www.chinaview.cn, "China starts building 3rd-generation nuclear power reactors using Westinghouse technologies," April 19, 2009.

127 D'Olier,Robert, et.al. *DOE NP2010 Nuclear Power Plant Construction Infrastructure Assessment*. Report MPR-2776, U.S. DOE, October 2005.

Of these technologies, the Westinghouse AP1000 and the GE ESBWR reactors are the most technologically advanced. However, the GE ESBWR reactor is still undergoing regulatory certifications through the NRC design certification process.[128] The Westinghouse AP1000 reactor received its NRC certification in 2006.[129]

Westinghouse states that the AP1000 design is:[130]

- Currently available in the worldwide marketplace.
- Based on standard Westinghouse pressurized water reactor (PWR).
- Technology that has achieved more than 2,500 reactor years of highly successful operation.
- An 1100 MWe design that is ideal for providing baseload generating capacity.
- Modular in design, promoting ready standardization and high construction quality.
- Economical to construct and maintain (less concrete and steel and fewer components and systems mean there is less to install, inspect and maintain).
- Designed to promote ease of operation (features most advanced instrumentation and control in the industry).

Primary Commercial Embodiment

California has two operating nuclear plants at Diablo Canyon Unit 1 & 2 (put into operation in 1985 and 1986, respectively) and San Onofre Units 2 & 3 (put into operation in 1981 and 1983, respectively). None of the current nuclear plant license applications being reviewed by the NRC are intended for plants in California, although plant owners for Diablo Canyon and San Onofre have begun license renewal feasibility studies. Pacific Gas and Electric (PG&E) plans to submit its license renewal feasibility study to the California Public Utilities Commission in 2011, and Southern California Edison (SCE) plans to submit its license application to the NRC in 2012.

Given long approval processes and construction lead times, the primary commercial embodiment in the United States in 2018 will be driven largely by the applications that are being filed currently. The NRC has received 17 applications for a combined license for construction and operation (COL) and estimates that the licensing process for a COL will take

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128 http://www.gepower.com/about/press/en/2009_press/051909b.htm, "GE Hitachi Nuclear Energy Announces ecomagination Approval Earned for Advanced Boiling Water Reactor," May 19, 2009.

129 http://www.nrc.gov/reactors/new-reactors/design-cert/ap1000.html,"Issued Design Certification - Advanced Passive 1000 (AP1000), Rev. 15"

130 http://www.ap1000.westinghousenuclear.com.

approximately 36 to 48 months to complete.[131] The COL is valid for 40 years and can be renewed for an additional 20 years. According to the Energy Information Administration, there is no assurance that any of the plants for which COL have been received will ultimately be built or operate. The clearest indicator of the extent of the *nuclear revival* in the United States will be the number and capacity of new reactors that actually go on-line. Submitting a COL application does not ensure a reactor will be built or even started and may reflect a goal to keep the nuclear option open rather than a full commitment.

Table 27. Expected New Nuclear Power Plant Applications[132]

Company*	Date of Application	Design	Date Accepted	Site Under Consideration	State	Existing Operating Plant
NRG Energy (52-012/013)***	9/20/2007	ABWR	11/29/2007	South Texas Project (2 units)	TX	Y
NuStart Energy (52-014/015)***	10/30/2007	AP1000	1/18/2008	Bellefonte (2 units)	AL	N
UNISTAR (52-016)***	07/13/2007 (Envir.) 03/13/2008 (Safety)	EPR	01/25/2008 06/03/2008	Calvert Cliffs (1 unit)	MD	Y
Dominion (52-017)***	11/27/2007	ESBWR	1/28/2008	North Anna (1 unit)	VA	Y
Duke (52-018/019)***	12/13/2007	AP1000	2/25/2008	William Lee Nuclear Station (2 units)	SC	N
Progress Energy (52-022/023)***	2/19/2008	AP1000	4/17/2008	Harris (2 units)	NC	Y
NuStart Energy (52-024)***	2/27/2008	ESBWR	4/17/2008	Grand Gulf (1 units)	MS	Y
Southern Nuclear Operating Co. (52-025/026)***	3/31/2008	AP1000	5/30/2008	Vogtle (2 units)	GA	Y
South Carolina Electric & Gas (52-027/028)***	3/31/2008	AP1000	7/31/2008	Summer (2 units)	SC	Y
Progress Energy (52-029/030) ***	7/30/2008	AP1000	10/6/2008	Levy County (2 units)	FL	N
Exelon (52-031/032)***	9/3/2008	ESWBR	10/30/2008	Victoria County (2 units)	TX	N

131 U.S. Nuclear Regulatory Commission. *Combined License Applications for New Reactors.* http://www.nrc.gov/reactors/new-reactors/col.html. Retrieved 5/15/2009.

132 U.S. Nuclear Regulatory Commission. *Expected New Nuclear Power Plant Applications, Updated July 2, 2009.* http://www.nrc.gov/reactors/new-reactors.html. Retrieved 7/15/2009.

Company*	Date of Application	Design	Date Accepted	Site Under Consideration	State	Existing Operating Plant
Detroit Edison (52-033)***	9/18/2008	ESBWR	11/25/2008	Fermi (1 unit)	MI	Y
Luminant Power (52-034/035)***	9/19/2008	USAPWR	12/2/2008	Comanche Peak (2 units)	TX	Y
Entergy (52-036)***	9/25/2008	ESBWR	12/4/2008	River Bend (1 unit)	LA	Y
AmerenUE (52-037)***	7/24/2008	EPR	12/12/2008	Callaway (1 unit)	MO	Y
UNISTAR (52-038)***	9/30/2008	EPR	12/12/2008	Nine Mile Point (1 unit)	NY	Y
PPL Generation (52-039)***	10/10/2008	EPR	12/19/2008	Bell Bend (1 unit)	PA	Y
Florida Power and Light (763)	6/30/2009	AP1000		Turkey Point (2 units)	FL	Y
Amarillo Power (752)	CY 2009	EPR		Vicinity of Amarillo (2 units)	TX	UNK
Alternate Energy Holdings (765)	CY 2009	EPR		Hammett (1 unit)	ID	N
Blue Castle Project	CY 2010	TBD		Utah	UT	N
2007 – 2011 Total Number of Applications = 22; Total Number of Units = 33						
*Project Numbers/Docket Numbers; **Yellow – Acceptance Review Ongoing; ***Blue – Accepted/Docketed						

Source: U.S. Nuclear Regulatory Commission. Expected New Nuclear Power Plant Applications, Updated July 2, 2009.

Cost Drivers

Market and Industry Changes

The U.S. Energy Information Administration (EIA) recently projected additions of about 12 GW of nuclear capacity coming on-line through 2030 in the United States. This assumes 3.4 GW of expansion at existing plants, license extensions for current reactors, 13.4 GW of new capacity (about 10 new plants), and 4.4 GW lost from plants being retired. Electricity generation from nuclear power is projected to increase from 806 billion kWh in 2007 to 907 billion kWh in 2030, as concerns about rising fossil fuel prices, energy security, and greenhouse gas emissions support the development of new nuclear generation.[133]

The development of new nuclear power reactors could be hindered by public concerns over plant safety, radioactive waste disposal, and nuclear material proliferation. Some nations may be deterred from expanding their nuclear programs by high capital and maintenance costs. According to the EIA, the estimated cost for new nuclear plants has been greatly increased by rising costs for construction materials, and when combined with unstable financial markets, new investments in nuclear power are uncertain. Despite these difficulties, the *International*

133 EIA, Annual Energy Outlook, 2009. Appendix A. http://www.eia.doe.gov/oiaf/aeo/pdf/appendixes.PDF.

Energy Outlook 2008 (IEO2008) case incorporates improved prospects for world nuclear power."[134] The IEO2008 projection for nuclear electricity generation in 2025 is 31% higher than the projection published in IEO2003 only five years ago.

Current Trends

Economic and Operating Trends

The industry is concerned about the adequacy of the skilled labor pool and loss of skilled laborers and engineers due to retirement and lack of new graduates seeking careers in nuclear engineering. The lack of skilled nuclear engineers, construction managers with nuclear experience, and skilled tradespeople (boilermakers, pipefitters, electricians, and ironworkers) are a significant bottleneck in nuclear plant construction. Large-scale revival of nuclear power in the United States will depend on the industry's approach to these critical labor issues. Already, the NP2010 recommendations contend that nuclear plant designs should be at a complete stage prior to issuance of EPC (engineer-procure-construct) contracts, so that labor supply can be properly estimated and managed.[135] This recommendation is different than many of the *fast track* construction methods used today.

One recent trend in the United States' nuclear power industry that might influence future performance has been an increased concentration of operations into fewer owner-operators. Concentrated ownership of nuclear reactors began in the 1990s as investor-owned utilities sought to either eliminate their nuclear risks and the risks of nuclear operating license extensions, or to concentrate those risks into a larger, nuclear-concentrated business. The effects of industry consolidation into fewer, more specialized nuclear operating companies are illustrated in the table below:

Table 28. Operators of U.S. reactors[136]

Organization	Capacity (MWe)	Share of Capacity
Exelon-AmerGen	16,850	17.3%
Entergy	9,033	9.2%
Duke	6,996	7.2%
TVA	6,658	6.8%
Southern	5,698	5.8%
2nd Five Firms	22,680	23.2%
Others (3+ Reactors)	7,164	7.3%
Others (<3 Reactors)	22,588	23.1%

Source: www.eia.gov

134 http://www.eia.doe.gov/oiaf/ieo/electricity.html.

135 D'Olier, Robert, et.al. *DOE NP2010 Construction Infrastructure Assessment*. U.S. Department of Energy, October 2005.

136 http://www.eia.doe.gov/cneaf/nuclear/page/analysis/nuclearpower.html.

Ownership percentages are smaller than the operating percentages above because many reactors operate under two sets of agreements: ownership agreements and operating agreements. Entergy and Exelon, both investor-owned utilities that are pursuing nuclear-based generation strategies, have both purchased management rights at nuclear plants. Overall, outside of Exelon, there is a roughly 5-10% share range of capacity exposure that nuclear operators are willing to hold as on balance sheet exposure, and this has led to some leveling out of the top nuclear operators over time.

The data in the table do not include the Stars group, which shares some responsibilities among the managers of many of the smaller managerial groupings.

Capacity uprating, or adding additional generating capacity due to advances in technology in either the power cycle or the turbine-generator set, has been a continuing trend in nuclear power, as it has also been in other, fossil-fired technologies. Continuing advances in technology can be used by nuclear plant operators to gain additional megawatt capacity and energy production from the same plant site, as better materials and blade applications come to market.

Typical capacity uprates can increase capacity of existing nuclear reactors approximately 5-20%.[137] EIA estimates the near-term potential of these uprates around 4 GWe, based on utility and regulatory public announcements. These uprates generally follow the same justification as is done in fossil-fired generation plant, where the incremental benefit of the uprate exceeds the incremental cost of retrofit and operation, viewed on a lifecycle basis.

Technology Trends

With 443 nuclear power reactors in use worldwide, nuclear generation provides approximately 16% of global electricity generation. Several industrialized countries use nuclear power as a primary source of electricity (Japan, Germany, and France – which produces 78% of its electricity from nuclear power).[138] Finland, Japan, Korea and China have active nuclear generation expansion programs underway. Today, the primary reactor embodiments are earlier-generation technologies known as Generation II reactors, which came on-line in the 1960s and 1970s. Some limited construction of Generation III reactors has gone into service, primarily in Asia. Most of today's nuclear rebirth has taken place as a result of the design evolution into advanced reactors known as Generation III+, and the future designs forthcoming as Generation IV reactor technologies.

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137 Ibid. [130].

138 IEA/OECD, "IEA Energy Technology Essentials – Nuclear Power." March 2007.

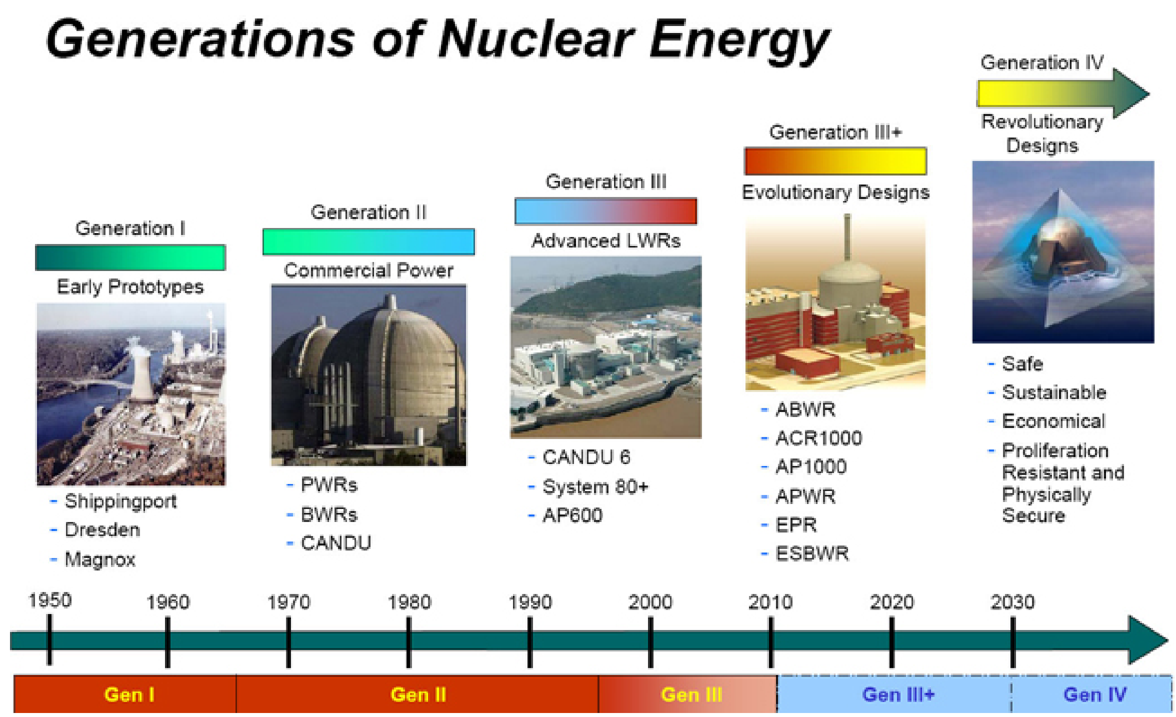

Figure 56. Generations of nuclear energy

Source: U.S. DOE and GIF, *A Technology Roadmap for Generation IV Nuclear Energy Systems.*

With the nuclear industry recovering from virtual stagnation over the last two decades, new factors in the energy landscape have implied a potentially larger role for nuclear power in supplying domestic energy needs. Issues such as global climate change and air quality suggest a future for carbon-free, emission-free nuclear technologies, while discussion over energy independence and security also reinforces the hypothesis that growing nuclear power generation in the United States could enhance the energy infrastructure and alleviate security concerns. However, it is clear that without a continued advancing of nuclear technology to reduce overall installed cost relative to fossil-fueled and other technologies, nuclear power will not enjoy the renaissance many advocates envision.[139]

To answer these issues and questions, the U.S. Department of Energy has led the development of new, next generation nuclear steam supply systems, known as Generation IV, Generation V, and nuclear fusion reactors. (Fusion reactors as described below are beyond the time frame of this study.)

<u>Generation IV Reactors (not feasible before 2030)</u>

Generation IV reactors are a set of theoretical nuclear reactor designs being researched by a consortium of 10 countries around the world. These designs are generally not expected to be available for commercial construction before 2030, which is beyond the horizon for this study.

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139 *The Future of Nuclear Power*. Massachusetts Institute of Technology, 2003.

Today's commercial reactors are typically of either Generation II or Generation III /III+ technologies, with most Generation I reactors having been retired from service.

In 1999, this consortium of international countries created the Generation IV International Forum (GIF) to research new reactor technologies based on eight fundamental objectives. The primary goals are to: improve nuclear safety, improve proliferation resistance, minimize waste and natural resource use, and to decrease the cost to build and run such plants.[140]

Several advanced reactor technologies are being evaluated for study, including:[141]

- Gas-cooled fast reactor
- Lead-cooled fast reactor
- Molten salt reactor
- Sodium-cooled fast reactor
- Supercritical water reactor
- Very-high-temperature reactor

Generation V+ Reactors (not feasible before 2030)

Generation V+ reactors are designs that may be theoretically possible but are not being actively considered for commercial development, either because of current technology application potential, or economics, or safety. These technologies include, but are not limited to:

- Liquid core reactor
- Gas core reactor
- Gas core EM reactor
- Fission fragment reactor

Fusion Reactors (not feasible before 2050)

The controlled power of nuclear fusion continues to be an area of active research in nuclear power technology, with the international ITER Tokamak fusion reactor now operational in Europe and scientific research continuing over the next several decades. Fusion of hydrogen isotopes in an ultra-high-temperature plasma carries with it the promise of virtually unlimited fuel supply and minimal radioactive waste products, but significant scientific and technical obstacles remain. A study done by the Swiss Federal Institute of Technology for the IEA

140 http://www.gen-4.org/PDFs/annual_report2007.PDF.

141 U.S. DOE and Nuclear Research Advisory Committee and the Generation IV International Forum *A Technology Roadmap for Generation IV Nuclear Energy Systems*. Report GIF-002-00, December 2002.

concluded that fusion reactors could become part of the technology landscape by 2050, but that widescale adoption would not take place until 2050-2100. [142]

Cost Drivers

It is difficult to take into account all aspects that drive costs within a particular nuclear power plant as the aging infrastructure has resulted in numerous one-time events. To accurately compare the cost of nuclear against other energy sources, this report has considered the following key cost drivers:

1. Capital costs

The Congressional Budget Office (CBO) has identified financing costs as an important cost driver in their report titled *Nuclear Power's Role in Generating Electricity* (May 2008).[143] Costs associated with initial construction of the plant are heavily influenced by factors such as construction on previously undeveloped land (known as *greenfields*), refurbishment, and replacements at existing sites and new unit additions at current sites.

For a nuclear plant the construction costs are generally higher than that for other fossil-fueled or renewable technologies because the buildings must be constructed especially for radiation containment. Redundant safety systems and advanced plant controls are present, adding additional costs. And all equipment, whether piping, valves, electrical equipment, and controls must all be certified to higher design specifications and standards for use in a nuclear power facility. However, nuclear plants do not require the types of post-combustion scrubbers and air emissions control technologies commonly found in fossil generation to remove sulfur dioxide, nitrogen oxides, and particulate matter.

Instant construction costs were obtained from a variety of research sources, including two MIT studies, research from the OECD-Nuclear Energy Agency, the IEA, and several other metastudies. The research team also evaluated several recent filings by Florida Power & Light for construction of an AP1000 reactor, and rating agency and investment bank cost estimates. Direct estimates were also obtained by the research team from Westinghouse and General Electric. Not taken into consideration were cost estimates from industry trade groups, as the capital costs outlined by those organizations did not match well with the larger body of knowledge in reported cost data. In any event, the research team notes that the cost spread for nuclear power is wide and somewhat uncertain and will remain so until new reactors are constructed in the United States.

For cost of capital and installed cost calculations a construction period of nine years was used as an average. This period includes siting, environmental impact studies, and licensing application

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142 Gnansounou, Edgard and Denis Bedniaguine. "Potential Role of Fusion Power Generation in a Very Long Term Electricity Supply Perspective: Case of Western Europe." SESE-V

143 Congress of the United States, Congressional Budget Office. *Nuclear Power's Role in Generating Electricity*. May 2008. Retrieved from: http://www.cbo.gov/ftpdocs/91xx/doc9133/05-02-Nuclear.PDF.

phases and is based on current French data for nuclear plant licensing and construction periods. The nine-year period is three to four years longer than the timeline recommended by the U.S. Nuclear Regulatory Commission and is based on the research team's view that the next wave of nuclear plants built in California will be subject to rigorous scrutiny and review. The time estimates of nine-year construction periods match up well with experience in both the historical context of actual built plant plus current build cycles in Europe.

The nine-year construction period estimate for nuclear plant construction, combined with utility financing of the nuclear power investment costs throughout the plant's useful life, means that utilities that construct nuclear power plants must account and plan for the significant increases in financial liquidity to meet the demands of financing a nuclear program. Several financial rating agencies have stated that utilities with nuclear programs should take adequate steps to insure liquidity to avoid rating downgrades.[144]

2. Fuel costs

Costs associated with the fuel used in the production of energy.

For a nuclear plant, these tend to be lower even though the following steps occur in the production of the fuel assemblies used in the reactor:

1. Mining of the uranium ore[145]
2. Conversion to U3O8 (uranium oxide - yellowcake form) and then to uranium hexafluoride
3. Enrichment from 0.7% U235 to 2-5% U235
4. Pelletization into usable uranium dioxide pellets (UO2)
5. Fabrication of pellets into rods, and then fuel assemblies [146]

Transportation costs comprising completed uranium fuel assemblies are comparable with coal transportation costs because of the vast amounts of uranium ore required for processing.

3. Operation and maintenance costs

Operation and maintenance costs for a nuclear power station are generally consistent with that of other fossil-fueled stations, including the costs of:

a) Labor and overheads (e.g., medical and pension benefits).
b) Consumable materials.
c) NRC and state license fees (e.g., license changes, on-site and regional inspectors, and headquarters staff).

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144 Moody's Investor Services, "New Nuclear Generating Capacity: Potential Credit Implications for U.S. Utilities," May 2008.

145 http://www.stockinterview.com/News/01092007/Uranium-Price-Forecast.html.

146 Tolley, George, et.al. *The Economic Future of Nuclear Power*. University of Chicago, August 2004.

d) Property taxes and insurance, which vary by state and locality.
e) Costs associated with plant outages and replacement/repair of major components.

Additional costs can be levied by the NRC for operating license reviews, or when plants require enhanced inspections following a significant deterioration in plant performance and safety. Also, additional costs can occur for enhanced security needs in the post-9/11 environment, which are difficult to quantify and are not included in the O&M cost tabulation.

Property taxes can result in a plant paying up to $ 15-20 million per year in property taxes.

4. Waste-related costs

For a nuclear plant, these costs include the surcharge levied by the Department of Energy for a nuclear waste fund to pay for the transportation and ultimate disposal of the spent nuclear fuel from reactors as well as costs associated with transportation and disposal of low-level radioactive wastes. The DOE charge for spent fuel disposal is a flat fee based on energy use. Low-level waste disposal costs are relatively modest during ongoing plant operations. However, a substantial quantity of low-level waste will need to be disposed of when the plants are decommissioned.

5. Decommissioning costs

The costs associated with dismantling a shutdown reactor, decontamination, and restoration of the plant site back to greenfield status. Usually restoration would occur over a long period, e.g. 20 years. Parts of the plant (e.g., non-nuclear plant components) could be used for energy generation by other sources.

In California, PG&E, SCE, and San Diego Gas & Electric (SDG&E) collect about 0.03 cents/kWh from retail rates to fund decommissioning. They must then report regularly to the NRC on the status of their decommissioning funds. As of 2001, $23.7 billion of the total estimated cost of decommissioning all United States' nuclear power plants had been collected, leaving a liability of about $11.6 billion to be covered over the operating lives of 104 reactors (on basis of average $320 million per unit).

The projected United States' industry average cost for decommissioning a power plant is $300 million. The funds for this activity are accumulated in the operating cost of the plant. The French and Swedish Nuclear Industries expect decommissioning costs to be 10 -15 % of the construction costs and budget this into the price charged for electricity. On the other hand the British decommissioning costs have been projected to be around 1 billion pounds per reactor. [147] In California, according to SCE, for SONGS 2 and 3, estimated decommissioning costs are $3.659

147 http://nuclearinfo.net/Nuclearpower/WebHomeCostOfNuclearPower

billion in 2008 dollars, and for SONGS 1, the estimate is $769.2 million. Rancho Seco's decommissioning costs were estimated to be $518 million (2002 dollars).[148]

Examples of several nuclear reactors dismantled in America, type, power, and decommissioning cost (often is mentioned only the probable cost per kilowatt of power):

Table 29. Nuclear decommissioning costs[149]

Country	Location	Reactor type	Operative Life	Decommissioning Phase	Dismantling Costs:
U.S.	Fort St. Vrain	High temperature, gas-cooled reactor (HTGR) [helium-graphite] 380 MWe	12 years (1977-1989)	Immediate Decon	$ 195 Million
U.S.	Maine Yankee	PWR 860 MWe	24 years (closed in 1996)	DECON COMPLETED - Demolished in 2004 (greenfield open to visitors)	$ 635 Million
U.S.	Connecticut Yankee	PWR 590 MWe	28 years (closed in 1996)	Decon - demolished in 2007 (greenfield open to visitors)	$ 820 Million

Source: http://nuclearinfo.net

Current Costs

Installation Costs

The summarized low/average/high costs are based on several research and financial sources (Keystone Center and Moody's Investor Service) as well as on the data provided by the major operators of the nuclear power plants (Florida Power & Light, Georgia Power and South Carolina Electric and Gas Company). These major owners and 27 other nuclear power companies/contractors have concluded in June 2007 that the cost for building new reactors would be between $3,600 and $4,000 per installed kW (with interest). They also projected that the operating costs for these plants would be remarkably expensive: $0.30/kWh for the first 13 years until construction costs are paid followed by $0.18/kWh over the remaining lifetime of the

148 Byron, Barbara, Research Team Communication with California Energy Commission Staff

149 http://nuclearinfo.net/Nuclearpower/WebHomeCostOfNuclearPower

plant. Just a few months later, in October 2007, Moody's Investor Service projected even higher costs due to the quickly escalating price of metals, forgings, other materials, and labor needed to construct reactors. They estimated total costs for new plants, including interest, at between $5,000 and $6,000 per installed kW. Florida Power & Light informed the Florida Public Service Commission in December 2007 that its estimated cost for building two new nuclear units at Turkey Point in South Florida was $8,000 per installed kW. Based on the rapidly changing nature of these cost estimates, and their resultant uncertainty, additional data sources were located because of the recent changes in installed cost estimates since 2007, which increased overall cost estimates used in this study. Moody's Investor Service recently updated its estimates for nuclear construction costs, indicating that construction costs are now projected at $7,000 per installed kW. [150] A recent study by Cooper details the rising trend in nuclear power construction costs and the widespread between estimates over recent years.[151]

Included in the installation/construction costs are: cooling towers, site works, transmission costs and risk management, plant components, project financing costs, license application, regulatory fees, initial fuel, insurance and taxes, escalation, and contingencies.

Financial Cost of Construction

The research team included costs for Allowance for Funds Used During Construction (AFUDC) in the preliminary analysis. The allowance for funds used during construction calculation, especially for nuclear plant construction, can be highly variable and is based on the total duration from plant inception to declaration of commercial operation.[152] While most sources, including the NRC, assume a construction spending profile of five years (60 months) duration, with pre-construction periods of 18 months, actual plant construction of 36 months, and start-up operations commissioning of 6 months, the research team lengthened the construction durations to reflect conditions and concerns in current reactor licensing efforts.

The research team concluded that reasonable basis for licensing and construction planning would be the experience seen in France, where there is considerable time spent in pre-construction phase plant licensing, permitting and study evaluations. This additional time lengthens the overall construction period to 8-10 years, and the research team used a construction period of nine years duration, and a construction spending profile as shown in the following table:

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150 Ibid. 144:

151 Mark Cooper, "The Economics of Nuclear Reactors: Renaissance or Relapse," Vermont Law School, June 2009.

152 Organisation for Economic Co-operation and Development. *Projected Costs of Generating Electricity: 2005 Update*. OECD Nuclear Energy Agency, International Energy Agency, 2005.

Table 30. Nuclear plant construction spending profile (% of total instant cost per year)

Year	1	2	3	4	5	6	7	8	9
% total instant cost	2.5	2	7	15.5	22	21	18	10	2

Source: OECD Nuclear Energy Agency, International Energy Agency, Organisation for Economic Co-operation and Development. Projected Costs of Generating Electricity: 2005 Update. OECD Publishing, 2005

The first three years are the cash flow spending projections used for pre-construction permitting, licensing, and environmental studies and approvals. Following approvals, the next six years is a spending profile consistent with the actual construction, start-up, commissioning, and testing of the nuclear plant.

Because of the minimal recent experience in nuclear plant licensing and approvals, the research team believes that a utility will devote significant time and efforts into the pre-construction licensing process. Three years duration is reasonable for additional site licensing, studies, and environmental impact findings leading to planning and regulatory approvals needed to begin actual construction. While the research team notes that the procurement method for nuclear power in France concentrates authority in a triumvirate between government, a government-sponsored utility, and a standard design, the choice of a nine-year construction duration is transferable to the United States and to California because of the historical track record of construction durations in this country, the concentration of the nuclear industry into an oligopoly of few commercial providers, and the increasing demand of the financial and utility industries for federal loan guarantees for nuclear plant. All of these coincident forces create an environment similar to current French experience.

Notable in the derivation of AFUDC for the nuclear case, the research team assumed that the interest rate, and thus the cost of funds, would be that of an investor-owned utility, and not that of a merchant generator or a public owned utility.

Expected Cost Trajectories

Expected cost trajectories for nuclear power options are expected to rise nominally with inflation, and only little experience curve effects, even based on the new Generation IV reactor designs. The lack of sufficient momentum in increasing the cumulative generation capacity represented by nuclear plants and the mature experience curve of the nuclear power industry caused the research team to model experience curve effects at a 95% rate (doubling of the installed capacity represents a 5% cost decrease due to experience).

Nominally, the research team expects that nuclear cost trajectories will rise at a rate greater than inflation as the new Generation IV reactors are begun. As new Generation IV reactors are built over the next several years and instant/installed cost ranges tighten, the research team expects nuclear escalation rates higher than normal cost inflation, but moderating in the 2018-2030 time period as follows:

- High Case: Additional 7% escalation through 2018, then additional 5% through 2030:
- Average Case: Additional 5% escalation through 2018, then additional 3% through 2030:
- Low Case: Additional 3% escalation through 2018, then nominal inflation through 2030.

4.0 Conclusions and Recommendations

KEMA performed a detailed assessment of the technologies that are likely to be deployed in the next 20 years. For each technology, KEMA conducted a quantitative and qualitative assessment of cost drivers and trends to develop input variables for the California Energy Commission's levelized cost model. KEMA performed a detailed literature review to support this study and identified utility-scale renewable energy and two non-renewable energy technologies that may likely be deployed in California over the next 20 years, along with identification of the infrastructure scales at which they are likely to be deployed.

For each technology, KEMA identified cost drive drivers and trends contributing to technology deployment and performed a quantitative assessment of factors to determine high, average, and low estimates of expected costs. In addition, KEMA has developed a detailed assessment of the expected trajectories for future costs for utility-scale generation. KEMA's research led to the development of detailed cost sheets that provide the input variables for the Commission's levelized cost analysis. The final project report will also address community and building-scale technologies as well as summarize key findings and recommendations.

Future cost of generation studies should consider including:

- Qualitative or quantitative assessment of other key issues that may influence costs of generation including:
  - CO_2 abatement costs
  - Environmental sensitivity
  - Land-use constraints
  - Permitting risk
  - Transmission constraints and equity issues related to who bears the cost of new transmission
  - System integration costs
  - System diversity
  - Tax credit availability and structure
  - Financing availability
  - Macro-economic benefits (jobs creation, security, fuel diversity, etc.)
  - Natural gas price and wholesale price effects associated with increased penetration of renewables
  - Carbon capture and storage
  - Storage (CAES, Battery, Pumped Hydro)
  - Dispatchability analysis
  - Other risk factors

- More time for a stakeholder input similar to the RETI process or CPUC GHG Modeling Initiatives.

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6.0 Glossary

ABWR	Advanced boiling water reactor
AC	Alternating current
AEA	Association for Educational Assessment (Europe)
AEO	Annual Energy Outlook
AFUDC	Allowance for funds used during construction
APS	Arizona Public Service
ASU	Air separation unit
AWEA	American Wind Energy Association
BOP	Balance of plant
BOS	Balance of systems
Btu	British thermal unit
BWR	Boiling water reactors
California ISO	California Independent System Operator
CBO	Congressional Budget Office
CCS	Carbon capture and sequestration
CFB	Circulating fluidized bed
CIBO	Council of Industrial Boiler Owners
CO	Carbon monoxide
CO_2	Carbon dioxide
COG	Cost of generation
COL	Construction and operation
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
CSP	Concentrating Solar power
DC	Direct current
DOE	Department of Energy

EAO	Electricity analysis office
EERE	Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
EM	Environmental management
EPRI	Electric Power Research Institute
ETSU	Energy Technology Support unit
EU	European Union
EWEA	European Wind Energy Association
FB	Fluidized bed
FERC	Federal Energy Regulatory Commission
FPV	Flat-plate photovoltaic
GADS	Generating Availability Data System
GDP	Gross domestic product
GE	General electric
GeothermEx	GeothermEx, Inc.
GHG	Greenhouse gas
GIF	GEN IV International Forum
GIF	Generation International Forum
GW	Gigawatt
GWe	Gigawatt electric
GWh	Gigawatt hour
HCE	Heat collec tion element
Hetch Hetchy	Hetch Hetchy Water and Power Division
HGTR	High temperature gas-cooled reactor
HPRA	Hydroelectric Resource Assessment
IEPR	*Integrated Energy Policy Report*
IGCC	Integrated gasification combined-cycle
INEEL	Idaho National Engineering and Environmental Laboratory

INL	Idaho National Laboratory
IPP	Independent power provide
ITC	Investment tax credit
kW	kilowatt
kWe	Kilowatt electric
kWp	Kilowatt peak
LBNL	Lawrence Berkeley National Laboratory
m	meter
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt hour
MWp	Megawatt peak
NERC	North American Energy Reliability Corporation
NOx	Nitrogen oxide
NRC	Nuclear Regulatory Commission
NRE	Non-renewable energy
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
O&M	Operation and maintenance
OECD	Organization of Economic Cooperation and Development
OWC	Oscillating water column
PBMR	Pebble bed modular reactor
PCFB	Pressurized circulating fluidized bed
PG&E	Pacific Gas and Electric
PGC	Public goods charge
PHWR	Pressurized heavy water reactor
PIER	Public Interest Energy Research
PPA	Power purchase agreement

PTC	Production tax credit
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PWR	Pressurized water reactors
RDF	Refuse derived fuel
RE	Renewable energy
REP	Renewable energy program
RETI	Renewable Energy Transmission Initiative
RPS	Renewables Portfolio Standard
RSCR	Riley selective catalytic reduction™
S&L	Sargent and Lundy
SCE	Southern California Edison
SCR	Selective catalytic reduction
SDG&E	San Diego Gas & Electric
SFPUC	San Francisco Public Utilities Commission
SOx	Sulfur dioxide
SRA	Strategic research agenda
U.S.	United States
UBC	Unburned carbon
Unocal	Union Oil Company of California
USGS	United States Geological Survey
Ux	Uranium exchange
WECC	Western Electricity Coordinating Council

APPENDIX A

Cost Data

Technology Name: **Biomass Combustion - Fluidized Bed Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	28	15	70
Station Service (%)	6.00%	7.00%	5.00%
Net Capacity (MW)	26.32	13.95	66.50
Net Energy (GWh)	196	92	524
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	24.88	13.19	62.86
Net Capacity Factor (NCF)	85.00%	75.00%	90.00%
Planned Percent of Year Operational	92.39%	88.65%	97.70%
Average Percent Output	100.0%	100.0%	100.0%
Net Energy Delivered to Load Center (GWh)	185.25	86.63	495.58
Forced Outage Rate (FOR)	8.00%	10.00%	6.00%
Scheduled Outage Factor (SOF)	3.00%	6.00%	2.00%
Curtailment (Hours)	60	120	0
Degradation Factors			
Capacity Degradation (%/Year)	0.10%	0.20%	0.00%
Heat Rate Degradation (%/Year)	0.15%	0.20%	0.10%
Emission Factors			
NOX (lbs/MWh)	0.074	0.074	0.074
VOC/ROG (Lbs/MWh)	0.009	0.009	0.009
CO (Lbs/MWh)	0.079	0.079	0.079
CO2 (lbs/MWh)	0.000	0.000	0.000
SOX (lbs/MWh)	0.020	0.020	0.020
PM10 (lbs/MWh)	0.100	0.200	0.025

Technology Name: **Biomass Combustion - Fluidized Bed Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	1	1	1	1	1	1	0.998957181	0.994689784	0.993153861	0.991454788
Instant Cost (Nominal $/Gross MW)	$3,200,000	$3,260,838	$3,322,833	$3,386,006	$3,450,380	$3,515,978	$3,582,823	$3,647,132	$3,700,595	$3,765,127	$3,830,145
Installed Cost (Nominal $/Gross MW)	$3,580,264	$3,648,331	$3,717,693	$3,788,373	$3,860,397	$3,933,790	$4,008,579	$4,084,790	$4,162,449	$4,241,585	$4,322,225
% Cost of last year of construction	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
% Cost next to last year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost of previous year of construction											
High	1	1	1	1	1	1	1	1.000502406	1.002566461	1.00331257	1.004139926
Instant Cost (Nominal $/Gross MW)	$4,800,000	$4,891,257	$4,984,249	$5,079,009	$5,175,570	$5,273,967	$5,374,235	$5,479,161	$5,594,848	$5,705,459	$5,818,725
Installed Cost (Nominal $/Gross MW)	$5,810,868	$5,921,344	$6,033,919	$6,148,635	$6,265,532	$6,384,652	$6,506,036	$6,629,728	$6,755,771	$6,884,211	$7,015,092
% Cost first year of construction	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Low	1	1	1	1	1	1	1	0.997391042	0.98675735	0.982946811	0.978741818
Instant Cost (Nominal $/Gross MW)	$1,600,000	$1,630,419	$1,661,416	$1,693,003	$1,725,190	$1,757,989	$1,791,412	$1,820,707	$1,835,542	$1,863,216	$1,890,517
Installed Cost (Nominal $/Gross MW)	$1,677,000	$1,708,883	$1,741,372	$1,774,479	$1,808,215	$1,842,592	$1,877,623	$1,913,320	$1,949,696	$1,986,764	$2,024,536
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.990617574	0.990357064	0.989558753	0.989219936	0.988245127	0.987627424	0.986618608	0.98506456	0.983981645	0.982000994
Instant Cost (Nominal $/Gross MW)	$3,899,668	$3,972,763	$4,045,029	$4,120,521	$4,194,722	$4,271,800	$4,348,568	$4,424,263	$4,503,420	$4,579,801
Installed Cost (Nominal $/Gross MW)	$4,404,399	$4,488,135	$4,573,462	$4,660,412	$4,749,016	$4,839,303	$4,931,307	$5,025,061	$5,120,596	$5,217,948
% Cost of last year of construction	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
% Cost next to last year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost of previous year of construction										
High	1.004548377	1.004675576	1.005065676	1.005231382	1.005708603	1.006011363	1.006506426	1.007270524	1.007804031	1.008782067
Instant Cost (Nominal $/Gross MW)	$5,931,762	$6,045,301	$6,162,625	$6,280,824	$6,403,272	$6,526,975	$6,654,337	$6,785,996	$6,918,673	$7,057,052
Installed Cost (Nominal $/Gross MW)	$7,148,462	$7,284,368	$7,422,857	$7,563,979	$7,707,785	$7,854,324	$8,003,649	$8,155,814	$8,310,871	$8,468,876
% Cost first year of construction	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Low	0.976673797	0.976030843	0.974062145	0.973227317	0.970827833	0.969309203	0.966832089	0.963023621	0.960375082	0.955542238
Instant Cost (Nominal $/Gross MW)	$1,922,388	$1,957,647	$1,990,842	$2,026,953	$2,060,396	$2,096,284	$2,130,679	$2,162,635	$2,197,690	$2,228,202
Installed Cost (Nominal $/Gross MW)	$2,063,026	$2,102,248	$2,142,215	$2,182,943	$2,224,445	$2,266,736	$2,309,830	$2,353,745	$2,398,494	$2,444,093
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Biomass Combustion - Fluidized Bed Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$99.50	$150.00	$70.00
Variable Cost ($/MWh)	$4.47	$10.00	$3.00

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	2,189,124	2,187,039	2,184,954	2,182,869	2,180,784	2,178,700	2,176,615	2,174,530	2,172,445	2,170,360	2,168,275
Fuel Cost $/mmBtu)											
Average	$2.00	$2.04	$2.08	$2.12	$2.16	$2.20	$2.24	$2.28	$2.33	$2.37	$2.41
High	$3.00	$2.55	$2.60	$2.65	$2.70	$2.75	$2.80	$2.85	$2.91	$2.96	$3.02
Low	$1.75	$1.53	$1.56	$1.59	$1.62	$1.65	$1.68	$1.71	$1.74	$1.78	$1.81
Heat Rate (Btu/kWh)											
Nominal	10500	10490	10480	10470	10460	10450	10440	10430	10420	10410	10400
High	11000	10990	10980	10970	10960	10950	10940	10930	10920	10910	10900
Low	9800	9790	9780	9770	9760	9750	9740	9730	9720	9710	9700

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	2,166,190	2,164,105	2,162,021	2,159,936	2,157,851	2,155,766	2,153,681	2,151,596	2,149,511	2,147,426
Fuel Cost $/mmBtu)										
Average	$2.46	$2.51	$2.55	$2.60	$2.65	$2.70	$2.75	$2.81	$2.86	$2.91
High	$3.08	$3.13	$3.19	$3.25	$3.32	$3.38	$3.44	$3.51	$3.58	$3.64
Low	$1.85	$1.88	$1.92	$1.95	$1.99	$2.03	$2.07	$2.11	$2.15	$2.19
Heat Rate (Btu/kWh)										
Nominal	10390	10380	10370	10360	10350	10340	10330	10320	10310	10300
High	10890	10880	10870	10860	10850	10840	10830	10820	10810	10800
Low	9690	9680	9670	9660	9650	9640	9630	9620	9610	9600

Technology Name: **Biomass Combustion - Fluidized Bed Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
Average	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Equity	40.0%	15.2%	50.0%	11.7%	0.0%	0.0%
Debt Financed:	60.0%	6.7%	50.0%	5.9%	100.0%	4.3%
Discount Rate (WACC)	9.7%		8.6%		4.3%	
High						
Equity	60.0%	18.0%	55.0%	15.0%	0.0%	0.0%
Debt Financed:	40.0%	10.0%	45.0%	9.0%	100.0%	7.0%
Discount Rate (WACC)	14.4%		11.9%		7.0%	
Low						
Equity	35.0%	14.0%	50.0%	10.0%	0.0%	0.0%
Debt Financed:	65.0%	6.0%	50.0%	5.9%	100.0%	4.0%
Discount Rate (WACC)	8.5%		7.7%		4.0%	

	Average	High	Low
Loan/Debt Term (Years)	12	20	10
Equipment Life (Years):	20	20	20
Economic/Book Life (Years)	20	20	20

Technology Name: **Biomass Combustion - Fluidized Bed Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
TDMA	Y	Y	N	Y	Y	N	Y	Y	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	30%	30%	30%	30%	30%	30%	30%	30%	30%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Biomass - Stoker Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	38	25	50
Station Service (%)	4.00%	7.00%	2.40%
Net Capacity (MW)	36.48	23.25	48.80
Net Energy (GWh)	272	153	385
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	34.48	21.98	46.13
Net Capacity Factor (NCF)	85.00%	75.00%	90.00%
Planned Percent of Year Operational	92.39%	88.65%	97.70%
Average Percent Output	100.0%	100.0%	100.0%
Net Energy Delivered to Load Center (GWh)	256.76	144.39	363.67
Forced Outage Rate (FOR)	8.00%	10.00%	6.00%
Scheduled Outage Factor (SOF)	3.00%	6.00%	2.00%
Curtailment (Hours)	60	120	0
Degradation Factors			
Capacity Degradation (%/Year)	0.10%	0.20%	0.00%
Heat Rate Degradation (%/Year)	0.15%	0.20%	0.10%
Emission Factors			
NOX (lbs/MWh)	0.075	0.075	0.075
VOC/ROG (Lbs/MWh)	0.012	0.012	0.012
CO (Lbs/MWh)	0.105	0.105	0.105
CO2 (lbs/MWh)	0.000	0.000	0.000
SOX (lbs/MWh)	0.034	0.034	0.034
PM10 (lbs/MWh)	0.100	0.200	0.025

Technology Name: **Biomass - Stoker Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average											
Instant Cost (Nominal $/Gross MW)	$2,600,000	$2,649,431	$2,699,801	$2,751,130	$2,803,434	$2,856,732	$2,911,044	$2,966,388	$3,022,785	$3,080,254	$3,138,815
Installed Cost (Nominal $/Gross MW)	$2,908,964	$2,964,269	$3,020,625	$3,078,053	$3,136,573	$3,196,205	$3,256,970	$3,318,892	$3,381,990	$3,446,288	$3,511,808
% Cost of last year of construction	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
% Cost next to last year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost of previous year of construction											
High											
Instant Cost (Nominal $/Gross MW)	$3,250,000	$3,311,789	$3,374,752	$3,438,912	$3,504,292	$3,570,915	$3,638,805	$3,707,985	$3,778,481	$3,850,317	$3,923,519
Installed Cost (Nominal $/Gross MW)	$4,049,672	$4,126,663	$4,205,119	$4,285,066	$4,366,533	$4,449,549	$4,534,143	$4,620,346	$4,708,187	$4,797,698	$4,888,911
% Cost first year of construction	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Low											
Instant Cost (Nominal $/Gross MW)	$1,749,800	$1,783,067	$1,816,966	$1,851,510	$1,886,711	$1,922,581	$1,959,133	$1,996,379	$2,034,334	$2,073,011	$2,112,422
Installed Cost (Nominal $/Gross MW)	$1,913,796	$1,950,181	$1,987,257	$2,025,039	$2,063,538	$2,102,770	$2,142,748	$2,183,485	$2,224,997	$2,267,299	$2,310,404
% Cost first year of construction	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
% Cost second year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average										
Instant Cost (Nominal $/Gross MW)	$3,198,490	$3,259,299	$3,321,264	$3,384,408	$3,448,752	$3,514,319	$3,581,132	$3,649,216	$3,718,595	$3,789,292
Installed Cost (Nominal $/Gross MW)	$3,578,574	$3,646,609	$3,715,938	$3,786,585	$3,858,575	$3,931,934	$4,006,687	$4,082,862	$4,160,484	$4,239,583
% Cost of last year of construction	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
% Cost next to last year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost of previous year of construction										
High										
Instant Cost (Nominal $/Gross MW)	$3,998,112	$4,074,124	$4,151,580	$4,230,510	$4,310,939	$4,392,898	$4,476,415	$4,561,520	$4,648,243	$4,736,615
Installed Cost (Nominal $/Gross MW)	$4,981,859	$5,076,573	$5,173,088	$5,271,438	$5,371,658	$5,473,783	$5,577,850	$5,683,895	$5,791,957	$5,902,073
% Cost first year of construction	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Low										
Instant Cost (Nominal $/Gross MW)	$2,152,584	$2,193,508	$2,235,211	$2,277,706	$2,321,010	$2,365,136	$2,410,102	$2,455,923	$2,502,614	$2,550,194
Installed Cost (Nominal $/Gross MW)	$2,354,329	$2,399,089	$2,444,700	$2,491,179	$2,538,541	$2,586,803	$2,635,983	$2,686,098	$2,737,166	$2,789,204
% Cost first year of construction	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
% Cost second year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost third year of construction										

Technology Name: **Biomass - Stoker Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$160.10	$200.00	$107.80
Variable Cost ($/MWh)	$6.98	$8.73	$4.70

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	3,112,428	3,109,599	3,106,769	3,103,940	3,101,110	3,098,281	3,095,451	3,092,622	3,089,792	3,086,963	3,084,133
Fuel Cost $/mmBtu)											
Average	$2.00	$2.04	$2.08	$2.12	$2.16	$2.20	$2.24	$2.28	$2.33	$2.37	$2.41
High	$3.00	$2.55	$2.60	$2.65	$2.70	$2.75	$2.80	$2.85	$2.91	$2.96	$3.02
Low	$1.75	$1.53	$1.56	$1.59	$1.62	$1.65	$1.68	$1.71	$1.74	$1.78	$1.81
Heat Rate (Btu/kWh)											
Nominal	11000	10990	10980	10970	10960	10950	10940	10930	10920	10910	10900
High	13500	13490	13480	13470	13460	13450	13440	13430	13420	13410	13400
Low	10250	10240	10230	10220	10210	10200	10190	10180	10170	10160	10150

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	3,081,304	3,078,474	3,075,645	3,072,815	3,069,986	3,067,156	3,064,327	3,061,497	3,058,668	3,055,838
Fuel Cost $/mmBtu)										
Average	$2.46	$2.51	$2.55	$2.60	$2.65	$2.70	$2.75	$2.81	$2.86	$2.91
High	$3.08	$3.13	$3.19	$3.25	$3.32	$3.38	$3.44	$3.51	$3.58	$3.64
Low	$1.85	$1.88	$1.92	$1.95	$1.99	$2.03	$2.07	$2.11	$2.15	$2.19
Heat Rate (Btu/kWh)										
Nominal	10890	10880	10870	10860	10850	10840	10830	10820	10810	10800
High	13390	13380	13370	13360	13350	13340	13330	13320	13310	13300
Low	10140	10130	10120	10110	10100	10090	10080	10070	10060	10050

Technology Name: **Biomass - Stoker Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital
Average						
Equity	40.0%	15.2%	50.0%	11.7%	0.0%	0.0%
Debt Financed:	60.0%	6.7%	50.0%	5.9%	100.0%	4.3%
Discount Rate (WACC)	9.7%		8.6%		4.3%	
High						
Equity	60.0%	18.0%	55.0%	15.0%	0.0%	0.0%
Debt Financed:	40.0%	10.0%	45.0%	9.0%	100.0%	7.0%
Discount Rate (WACC)	14.4%		11.9%		7.0%	
Low						
Equity	35.0%	14.0%	50.0%	10.0%	0.0%	0.0%
Debt Financed:	65.0%	6.0%	50.0%	5.9%	100.0%	4.0%
Discount Rate (WACC)	8.5%		7.7%		4.0%	

	Average	High	Low
Loan/Debt Term (Years)	12	20	10
Equipment Life (Years):	20	20	20
Economic/Book Life (Years)	20	20	20

Technology Name: **Biomass - Stoker Boiler**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
TDMA	Y	Y	N	Y	Y	N	Y	Y	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	30%	30%	30%	30%	30%	30%	30%	30%	30%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Biomass - Cofiring**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	20	10	40
Station Service (%)	2.40%	2.40%	2.40%
Net Capacity (MW)	19.52	9.76	39.04
Net Energy (GWh)	154	81	291
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	1.49%	1.49%	1.49%
Load Center Delivered Capacity (MW)	19.13	9.57	38.27
Net Capacity Factor (NCF)	90.00%	95.00%	85.00%
Planned Percent of Year Operational	90.45%	97.08%	85.41%
Average Percent Output	100.0%	100.0%	100.0%
Net Energy Delivered to Load Center (GWh)	150.84	79.61	284.93
Forced Outage Rate (FOR)	0.50%	1.00%	0.10%
Scheduled Outage Factor (SOF)	0.77%	1.15%	0.38%
Curtailment (Hours)	0	0	0
Degradation Factors			
Capacity Degradation (%/Year)	0.00%	0.00%	0.00%
Heat Rate Degradation (%/Year)	0.00%	0.00%	0.00%
Emission Factors			
NOX (lbs/MWh)	0.093	0.064	0.064
VOC/ROG (Lbs/MWh)	0.023	0.018	0.018
CO (Lbs/MWh)	0.093	0.050	0.050
CO2 (lbs/MWh)	1083.844	828.140	828.140
SOX (lbs/MWh)	0.009	0.007	0.007
PM10 (lbs/MWh)	0.065	0.028	0.028

Technology Name: **Biomass - Cofiring**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average											
Instant Cost (Nominal $/Gross MW)	$500,000	$509,506	$519,193	$529,063	$539,122	$549,372	$559,816	$570,459	$581,305	$592,356	$603,618
Installed Cost (Nominal $/Gross MW)	$524,250	$534,217	$544,373	$554,723	$565,269	$576,016	$586,967	$598,127	$609,498	$621,086	$632,894
% Cost of last year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost next to last year of construction											
% Cost of previous year of construction											
High											
Instant Cost (Nominal $/Gross MW)	$700,000	$636,882	$648,991	$661,329	$673,902	$686,714	$699,770	$713,074	$726,631	$740,446	$754,523
Installed Cost (Nominal $/Gross MW)	$750,400	$764,666	$779,204	$794,018	$809,114	$824,497	$840,172	$856,145	$872,422	$889,009	$905,910
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											
Low											
Instant Cost (Nominal $/Gross MW)	$400,000	$407,605	$415,354	$423,251	$431,297	$439,497	$447,853	$456,367	$465,044	$473,885	$482,895
Installed Cost (Nominal $/Gross MW)	$417,000	$424,928	$433,007	$441,239	$449,628	$458,176	$466,887	$475,763	$484,808	$494,025	$503,418
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average										
Instant Cost (Nominal $/Gross MW)	$615,094	$626,788	$638,705	$650,848	$663,221	$675,831	$688,679	$701,772	$715,114	$728,710
Installed Cost (Nominal $/Gross MW)	$644,926	$657,187	$669,682	$682,414	$695,388	$708,608	$722,080	$735,808	$749,797	$764,052
% Cost of last year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost next to last year of construction										
% Cost of previous year of construction										
High										
Instant Cost (Nominal $/Gross MW)	$768,868	$783,485	$798,381	$813,560	$829,027	$844,788	$860,849	$877,215	$893,893	$910,888
Installed Cost (Nominal $/Gross MW)	$923,133	$940,684	$958,568	$976,792	$995,363	$1,014,286	$1,033,570	$1,053,220	$1,073,244	$1,093,648
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										
Low										
Instant Cost (Nominal $/Gross MW)	$492,075	$501,431	$510,964	$520,678	$530,577	$540,664	$550,943	$561,418	$572,092	$582,968
Installed Cost (Nominal $/Gross MW)	$512,989	$522,741	$532,680	$542,807	$553,127	$563,643	$574,359	$585,278	$596,405	$607,744
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Biomass - Cofiring**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$15.0	$21.00	$12.00
Variable Cost ($/MWh)	$1.27	$1.78	$1.02

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	1,655,640	1,654,063	1,652,486	1,650,910	1,649,333	1,647,756	1,646,179	1,644,602	1,643,026	1,641,449	1,639,872
Fuel Cost $/mmBtu)											
Average	$2.00	$2.04	$2.08	$2.12	$2.16	$2.20	$2.24	$2.28	$2.33	$2.37	$2.41
High	$3.00	$2.55	$2.60	$2.65	$2.70	$2.75	$2.80	$2.85	$2.91	$2.96	$3.02
Low	$1.75	$1.53	$1.56	$1.59	$1.62	$1.65	$1.68	$1.71	$1.74	$1.78	$1.81
Heat Rate (Btu/kWh)											
Nominal	10500	10490	10480	10470	10460	10450	10440	10430	10420	10410	10400
High	12000	11990	11980	11970	11960	11950	11940	11930	11920	11910	11900
Low	9800	9790	9780	9770	9760	9750	9740	9730	9720	9710	9700

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	1,638,295	1,636,718	1,635,142	1,633,565	1,631,988	1,630,411	1,628,834	1,627,258	1,625,681	1,624,104
Fuel Cost $/mmBtu)										
Average	$2.46	$2.51	$2.55	$2.60	$2.65	$2.70	$2.75	$2.81	$2.86	$2.91
High	$3.08	$3.13	$3.19	$3.25	$3.32	$3.38	$3.44	$3.51	$3.58	$3.64
Low	$1.85	$1.88	$1.92	$1.95	$1.99	$2.03	$2.07	$2.11	$2.15	$2.19
Heat Rate (Btu/kWh)										
Nominal	10390	10380	10370	10360	10350	10340	10330	10320	10310	10300
High	11890	11880	11870	11860	11850	11840	11830	11820	11810	11800
Low	9690	9680	9670	9660	9650	9640	9630	9620	9610	9600

Technology Name: **Biomass - Cofiring**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital
Average						
Equity	40.0%	15.2%	50.0%	11.7%	0.0%	0.0%
Debt Financed:	60.0%	6.7%	50.0%	5.9%	100.0%	4.3%
Discount Rate (WACC)	9.7%		8.6%		4.3%	
High						
Equity	60.0%	18.0%	55.0%	15.0%	0.0%	0.0%
Debt Financed:	40.0%	10.0%	45.0%	9.0%	100.0%	7.0%
Discount Rate (WACC)	14.4%		11.9%		7.0%	
Low						
Equity	35.0%	14.0%	50.0%	10.0%	0.0%	0.0%
Debt Financed:	65.0%	6.0%	50.0%	5.9%	100.0%	4.0%
Discount Rate (WACC)	8.5%		7.7%		4.0%	

	Average	High	Low
Loan/Debt Term (Years)	12	20	10
Equipment Life (Years):	20	20	20
Economic/Book Life (Years)	20	20	20

Technology Name: **Biomass - Cofiring**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	20	20	20
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
TDMA	Y	Y	N	Y	Y	N	Y	Y	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	30%	30%	30%	30%	30%	30%	30%	30%	30%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Biomass - Cogasification IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	30	25	40
Station Service (%)	3.50%	4.50%	2.50%
Net Capacity (MW)	28.95	23.88	39.00
Net Energy (GWh)	190	125	290
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	27.36	22.57	36.86
Net Capacity Factor (NCF)	75.00%	60.00%	85.00%
Planned Percent of Year Operational	81.52%	70.92%	92.27%
Average Percent Output	100.0%	100.0%	100.0%
Net Energy Delivered to Load Center (GWh)	179.79	118.62	274.49
Forced Outage Rate (FOR)	8.00%	10.00%	6.00%
Scheduled Outage Factor (SOF)	3.00%	6.00%	2.00%
Curtailment (Hours)	0	0	0
Degradation Factors			
Capacity Degradation (%/Year)	0.05%	0.10%	0.00%
Heat Rate Degradation (%/Year)	0.20%	0.25%	0.15%
Emission Factors			
NOX (lbs/MWh)	0.074	0.074	0.074
VOC/ROG (Lbs/MWh)	0.009	0.009	0.009
CO (Lbs/MWh)	0.029	0.029	0.029
CO2 (lbs/MWh)	0.000	0.000	0.000
SOX (lbs/MWh)	0.020	0.020	0.020
PM10 (lbs/MWh)	0.100	0.200	0.025

Technology Name: **Biomass - Cogasification IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average											
Instant Cost (Nominal $/Gross MW)	$2,950,000	$3,006,085	$3,063,236	$3,121,474	$3,180,819	$3,241,292	$3,302,915	$3,365,710	$3,429,698	$3,494,903	$3,561,348
Installed Cost (Nominal $/Gross MW)	$3,316,329	$3,379,379	$3,443,627	$3,509,097	$3,575,811	$3,643,794	$3,713,070	$3,783,662	$3,855,596	$3,928,898	$4,003,594
% Cost of last year of construction	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
% Cost next to last year of construction	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
% Cost of previous year of construction											
High											
Instant Cost (Nominal $/Gross MW)	$3,687,500	$3,757,606	$3,829,045	$3,901,843	$3,976,024	$4,051,615	$4,128,644	$4,207,137	$4,287,123	$4,368,629	$4,451,685
Installed Cost (Nominal $/Gross MW)	$4,594,820	$4,682,176	$4,771,193	$4,861,902	$4,954,336	$5,048,527	$5,144,509	$5,242,315	$5,341,981	$5,443,542	$5,547,034
% Cost first year of construction	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Low											
Instant Cost (Nominal $/Gross MW)	$2,655,000	$2,254,564	$2,297,427	$2,341,106	$2,385,614	$2,430,969	$2,477,186	$2,524,282	$2,572,274	$2,621,177	$2,671,011
Installed Cost (Nominal $/Gross MW)	$2,767,243	$2,819,854	$2,873,464	$2,928,094	$2,983,763	$3,040,490	$3,098,295	$3,157,199	$3,217,224	$3,278,389	$3,340,717
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average										
Instant Cost (Nominal $/Gross MW)	$3,629,056	$3,698,051	$3,768,358	$3,840,001	$3,913,007	$3,987,400	$4,063,208	$4,140,457	$4,219,175	$4,299,389
Installed Cost (Nominal $/Gross MW)	$4,079,710	$4,157,273	$4,236,310	$4,316,850	$4,398,922	$4,482,553	$4,567,775	$4,654,617	$4,743,110	$4,833,285
% Cost of last year of construction	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
% Cost next to last year of construction	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
% Cost of previous year of construction										
High										
Instant Cost (Nominal $/Gross MW)	$4,536,320	$4,622,563	$4,710,447	$4,800,001	$4,891,258	$4,984,250	$5,079,010	$5,175,571	$5,273,969	$5,374,236
Installed Cost (Nominal $/Gross MW)	$5,652,494	$5,759,958	$5,869,465	$5,981,055	$6,094,766	$6,210,639	$6,328,714	$6,449,035	$6,571,643	$6,696,582
% Cost first year of construction	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Low										
Instant Cost (Nominal $/Gross MW)	$2,721,792	$2,773,538	$2,826,268	$2,880,001	$2,934,755	$2,990,550	$3,047,406	$3,105,343	$3,164,381	$3,224,542
Installed Cost (Nominal $/Gross MW)	$3,404,230	$3,468,951	$3,534,902	$3,602,107	$3,670,590	$3,740,375	$3,811,486	$3,883,950	$3,957,791	$4,033,036
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Biomass - Cogasification IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$150.0	$175.00	$125.00
Variable Cost ($/MWh)	$4.00	$4.50	$3.00

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	2,069,550	2,067,579	2,065,608	2,063,637	2,061,666	2,059,695	2,057,724	2,055,753	2,053,782	2,051,811	2,049,840
Fuel Cost $/mmBtu)											
Average	$2.00	$2.04	$2.08	$2.12	$2.16	$2.20	$2.24	$2.28	$2.33	$2.37	$2.41
High	$3.00	$2.55	$2.60	$2.65	$2.70	$2.75	$2.80	$2.85	$2.91	$2.96	$3.02
Low	$1.75	$1.53	$1.56	$1.59	$1.62	$1.65	$1.68	$1.71	$1.74	$1.78	$1.81
Heat Rate (Btu/kWh)											
Nominal	10500	10490	10480	10470	10460	10450	10440	10430	10420	10410	10400
High	11000	10990	10980	10970	10960	10950	10940	10930	10920	10910	10900
Low	10000	9990	9980	9970	9960	9950	9940	9930	9920	9910	9900

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	2,047,869	2,045,898	2,043,927	2,041,956	2,039,985	2,038,014	2,036,043	2,034,072	2,032,101	2,030,130
Fuel Cost $/mmBtu)										
Average	$2.46	$2.51	$2.55	$2.60	$2.65	$2.70	$2.75	$2.81	$2.86	$2.91
High	$3.08	$3.13	$3.19	$3.25	$3.32	$3.38	$3.44	$3.51	$3.58	$3.64
Low	$1.85	$1.88	$1.92	$1.95	$1.99	$2.03	$2.07	$2.11	$2.15	$2.19
Heat Rate (Btu/kWh)										
Nominal	10390	10380	10370	10360	10350	10340	10330	10320	10310	10300
High	10890	10880	10870	10860	10850	10840	10830	10820	10810	10800
Low	9890	9880	9870	9860	9850	9840	9830	9820	9810	9800

Technology Name: **Biomass - Cogasification IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital
Average						
Equity	40.0%	15.2%	50.0%	11.7%	0.0%	0.0%
Debt Financed:	60.0%	6.7%	50.0%	5.9%	100.0%	4.3%
Discount Rate (WACC)	9.7%		8.6%		4.3%	
High						
Equity	60.0%	18.0%	55.0%	15.0%	0.0%	0.0%
Debt Financed:	40.0%	10.0%	45.0%	9.0%	100.0%	7.0%
Discount Rate (WACC)	14.4%		11.9%		7.0%	
Low						
Equity	35.0%	14.0%	50.0%	10.0%	0.0%	0.0%
Debt Financed:	65.0%	6.0%	50.0%	5.9%	100.0%	4.0%
Discount Rate (WACC)	8.5%		7.7%		4.0%	

	Average	High	Low
Loan/Debt Term (Years)	15	20	10
Equipment Life (Years):	20	20	20
Economic/Book Life (Years)	20	20	20

Technology Name: **Biomass - Cogasification IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	**High**	**Low**
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	20	20	20

	Average			**High**			**Low**		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
TDMA	Y	Y	N	Y	Y	N	Y	Y	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	30%	30%	30%	30%	30%	30%	30%	30%	30%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Geothermal - Binary**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	15	2	50
Station Service (%)	5.00%	10.00%	5.00%
Net Capacity (MW)	14.25	1.80	47.50
Net Energy (GWh)	112	13	395
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	13.47	1.70	44.90
Net Capacity Factor (NCF)	90%	80%	95%
Planned Percent of Year Operational	100.0%	100.0%	100.0%
Average Percent Output	96.15%	93.53%	99.12%
Net Energy Delivered to Load Center (GWh)	106	12	374
Forced Outage Rate (FOR)	2.5%	2.8%	2.2%
Scheduled Outage Factor (SOF)	4.00%	12.00%	2.00%
Curtailment (Hours)	0.0	0.0	0.0
Degradation Factors			
Capacity Degradation (%/Year)	4.00%	4.00%	4.00%
Heat Rate Degradation (%/Year)	0	0	0
Emission Factors			
NOX (lbs/MWh)	0	0	0
VOC/ROG (Lbs/MWh)	0	0	0
CO (Lbs/MWh)	0	0	0
CO2 (lbs/MWh)	0	0	0
SOX (lbs/MWh)	0	0	0
PM10 (lbs/MWh)	0	0	0

Technology Name: **Geothermal - Binary**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	0.982755954	0.973551831	0.973551831	0.973551831	0.973551831	0.973551831	0.973551831	0.969375668	0.969375668	0.969375668
Instant Cost (Nominal $/Gross MW)	$4,046,000	$4,050,101	$4,157,032	$4,271,500	$4,346,667	$4,421,833	$4,497,000	$4,572,167	$4,627,398	$4,722,500	$4,797,667
Installed Cost (Nominal $/Gross MW)	$4,846,345	$4,851,257	$4,979,341	$5,116,452	$5,206,487	$5,296,523	$5,386,558	$5,476,594	$5,542,750	$5,656,665	$5,746,700
% Cost first year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
High	1	0.987823163	0.981297861	0.981297861	0.981297861	0.981297861	0.981297861	0.981297861	0.978331142	0.978331142	0.978331142
Instant Cost (Nominal $/Gross MW)	$5,948,000	$5,984,729	$6,128,253	$6,279,506	$6,390,008	$6,500,510	$6,611,012	$6,721,514	$6,811,361	$6,942,518	$7,053,020
Installed Cost (Nominal $/Gross MW)	$7,980,719	$8,030,000	$8,222,573	$8,425,517	$8,573,783	$8,722,049	$8,870,314	$9,018,580	$9,139,133	$9,315,112	$9,463,378
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	1	0.978866461	0.967620759	0.967620759	0.967620759	0.967620759	0.967620759	0.967620759	0.962526251	0.962526251	0.962526251
Instant Cost (Nominal $/Gross MW)	$2,353,000	$2,346,063	$2,412,391	$2,484,142	$2,527,856	$2,571,570	$2,615,284	$2,658,999	$2,688,483	$2,746,427	$2,790,141
Installed Cost (Nominal $/Gross MW)	$2,746,209	$2,738,112	$2,815,525	$2,899,266	$2,950,285	$3,001,304	$3,052,323	$3,103,342	$3,137,754	$3,205,381	$3,256,400
% Cost first year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.966437265	0.966437265	0.966437265	0.966437265	0.962958958	0.958985286	0.951730924	0.944761448	0.941492513	0.929936956
Instant Cost (Nominal $/Gross MW)	$4,858,063	$4,948,000	$5,023,167	$5,098,333	$5,154,880	$5,227,008	$5,283,560	$5,359,463	$5,455,225	$5,481,222
Installed Cost (Nominal $/Gross MW)	$5,819,043	$5,926,771	$6,016,806	$6,106,842	$6,174,574	$6,260,970	$6,328,709	$6,419,626	$6,534,332	$6,565,471
% Cost first year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
High	0.976241455	0.976241455	0.976241455	0.976241455	0.973765377	0.970933429	0.96575444	0.96076783	0.958425186	0.950124671
Instant Cost (Nominal $/Gross MW)	$7,148,221	$7,274,025	$7,384,527	$7,495,029	$7,586,240	$7,693,593	$7,784,788	$7,896,054	$8,027,916	$8,087,388
Installed Cost (Nominal $/Gross MW)	$9,591,114	$9,759,910	$9,908,176	$10,056,442	$10,178,825	$10,322,865	$10,445,226	$10,594,518	$10,771,443	$10,851,238
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	0.958944685	0.958944685	0.958944685	0.958944685	0.954708246	0.949872742	0.941056801	0.932601485	0.928640528	0.914663879
Instant Cost (Nominal $/Gross MW)	$2,823,310	$2,877,569	$2,921,283	$2,964,997	$2,995,419	$3,036,965	$3,067,403	$3,111,642	$3,170,046	$3,178,709
Installed Cost (Nominal $/Gross MW)	$3,295,112	$3,358,438	$3,409,457	$3,460,476	$3,495,982	$3,544,470	$3,579,996	$3,631,627	$3,699,791	$3,709,901
% Cost first year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Technology Name: **Geothermal - Binary**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$47.44	$54.56	$40.32
Variable Cost ($/MWh)	$4.55	$5.12	$4.31

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Name: **Geothermal - Binary**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital
Average						
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	High	Low
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	30	30	30
Economic/Book Life (Years)	30	30	30

Technology Name: **Geothermal - Binary**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	N	N	Y	N	N	Y	N	N	Y
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	25%	25%	25%	25%	25%	25%	25%	25%	25%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2005	2005	2005	2005	2005	2005	2005	2005	2005
REPTC In Start Year	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2006	2006	2006	2006	2006	2006	2006	2006	2006
REPI In Start Year ($/kWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Technology Name: **Geothermal - Flash**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	30	7	50
Station Service (%)	5.00%	5.00%	5.00%
Net Capacity (MW)	28.50	6.65	47.50
Net Energy (GWh)	235	52	408
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	26.94	6.29	44.90
Net Capacity Factor (NCF)	94%	90%	98%
Planned Percent of Year Operational	100.0%	100.0%	100.0%
Average Percent Output	100.43%	105.22%	102.25%
Net Energy Delivered to Load Center (GWh)	222	50	385
Forced Outage Rate (FOR)	2.5%	2.8%	2.2%
Scheduled Outage Factor (SOF)	4.00%	12.00%	2.00%
Curtailment (Hours)	0.0	0.0	0.0
Degradation Factors			
Capacity Degradation (%/Year)	4.00%	4.00%	4.00%
Heat Rate Degradation (%/Year)	0	0	0
Emission Factors			
NOX (lbs/MWh)	0.191	0.191	0.191
VOC/ROG (Lbs/MWh)	0.011	0.011	0.011
CO (Lbs/MWh)	0.058	0.058	0.058
CO2 (lbs/MWh)	60	60	60
SOX (lbs/MWh)	0.026	0.026	0.026
PM10 (lbs/MWh)	0	0	0

Technology Name: **Geothermal - Flash**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	0.982755954	0.973551831	0.973551831	0.973551831	0.973551831	0.973551831	0.973551831	0.969375668	0.969375668	0.969375668
Instant Cost (Nominal $/Gross MW)	$3,676,000	$3,679,726	$3,776,878	$3,880,878	$3,949,171	$4,017,464	$4,085,757	$4,154,050	$4,204,230	$4,290,635	$4,358,928
Installed Cost (Nominal $/Gross MW)	$4,403,155	$4,407,618	$4,523,988	$4,648,561	$4,730,362	$4,812,164	$4,893,966	$4,975,768	$5,035,875	$5,139,372	$5,221,174
% Cost first year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
High	1	0.987823163	0.981297861	0.981297861	0.981297861	0.981297861	0.981297861	0.981297861	0.978331142	0.978331142	0.978331142
Instant Cost (Nominal $/Gross MW)	$5,329,000	$5,361,906	$5,490,495	$5,626,007	$5,725,009	$5,824,011	$5,923,014	$6,022,016	$6,102,513	$6,220,020	$6,319,023
Installed Cost (Nominal $/Gross MW)	$7,150,177	$7,194,329	$7,366,862	$7,548,685	$7,681,521	$7,814,357	$7,947,193	$8,080,029	$8,188,036	$8,345,702	$8,478,538
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	1	0.978866461	0.967620759	0.967620759	0.967620759	0.967620759	0.967620759	0.967620759	0.962526251	0.962526251	0.962526251
Instant Cost (Nominal $/Gross MW)	$2,603,000	$2,595,326	$2,668,701	$2,748,076	$2,796,434	$2,844,793	$2,893,151	$2,941,510	$2,974,127	$3,038,227	$3,086,586
Installed Cost (Nominal $/Gross MW)	$3,007,075	$2,998,210	$3,082,976	$3,174,672	$3,230,537	$3,286,403	$3,342,268	$3,398,134	$3,435,814	$3,509,865	$3,565,730
% Cost first year of construction	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
% Cost second year of construction	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
% Cost third year of construction	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.966437265	0.966437265	0.966437265	0.966437265	0.962958958	0.958985286	0.951730924	0.944761448	0.941492513	0.929936956
Instant Cost (Nominal $/Gross MW)	$4,413,801	$4,495,513	$4,563,806	$4,632,099	$4,683,475	$4,749,007	$4,800,388	$4,869,349	$4,956,354	$4,979,974
Installed Cost (Nominal $/Gross MW)	$5,286,901	$5,384,778	$5,466,579	$5,548,381	$5,609,920	$5,688,414	$5,749,959	$5,832,562	$5,936,778	$5,965,070
% Cost first year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
High	0.976241455	0.976241455	0.976241455	0.976241455	0.973765377	0.970933429	0.96575444	0.96076783	0.958425186	0.950124671
Instant Cost (Nominal $/Gross MW)	$6,404,316	$6,517,027	$6,616,029	$6,715,032	$6,796,751	$6,892,931	$6,974,636	$7,074,323	$7,192,462	$7,245,744
Installed Cost (Nominal $/Gross MW)	$8,592,980	$8,744,210	$8,877,046	$9,009,882	$9,119,529	$9,248,579	$9,358,206	$9,491,961	$9,650,474	$9,721,965
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	0.958944685	0.958944685	0.958944685	0.958944685	0.954708246	0.949872742	0.941056801	0.932601485	0.928640528	0.914663879
Instant Cost (Nominal $/Gross MW)	$3,123,279	$3,183,303	$3,231,662	$3,280,020	$3,313,675	$3,359,634	$3,393,307	$3,442,246	$3,506,855	$3,516,438
Installed Cost (Nominal $/Gross MW)	$3,608,120	$3,677,461	$3,733,327	$3,789,192	$3,828,071	$3,881,165	$3,920,065	$3,976,601	$4,051,240	$4,062,310
% Cost first year of construction	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
% Cost second year of construction	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
% Cost third year of construction	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%

Technology Name: **Geothermal - Flash**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$58.38	$67.14	$49.62
Variable Cost ($/MWh)	$5.06	$5.28	$4.85

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Name: **Geothermal - Flash**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
Average	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	High	Low
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	30	30	30
Economic/Book Life (Years)	30	30	30

Technology Name: **Geothermal - Flash**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For Geothermal Depletion Allowance	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	10%	10%	10%	10%	10%	10%	10%	10%	10%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Hydro - Developed sites without power**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	15	1.5	300
Station Service (%)	10.00%	13.00%	9.20%
Net Capacity (MW)	13.50	1.31	272.40
Net Energy (GWh)	36	1	1468
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	7.50%	7.50%	7.50%
Load Center Delivered Capacity (MW)	12.43	1.20	250.71
Net Capacity Factor (NCF)	30.40%	12.50%	61.50%
Planned Percent of Year Operational	100.0%	100.0%	100.0%
Average Percent Output	35.35%	14.81%	70.39%
Net Energy Delivered to Load Center (GWh)	33	1	1351
Forced Outage Rate (FOR)	5.1%	6.7%	3.8%
Scheduled Outage Factor (SOF)	9.40%	9.56%	9.20%
Curtailment (Hours)	0.0	0.0	0.0
Degradation Factors			
Capacity Degradation (%/Year)	2.00%	2.25%	1.75%
Heat Rate Degradation (%/Year)	0	0	0
Emission Factors			
NOX (lbs/MWh)	0	0	0
VOC/ROG (Lbs/MWh)	0	0	0
CO (Lbs/MWh)	0	0	0
CO2 (lbs/MWh)	0	0	0
SOX (lbs/MWh)	0	0	0
PM10 (lbs/MWh)	0	0	0

Technology Name: **Hydro - Developed sites without power**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	1	1	1	1	1	1	1	1	1	1
Instant Cost (Nominal $/Gross MW)	$1,730,000	$1,762,140	$1,794,280	$1,826,420	$1,858,560	$1,890,700	$1,922,840	$1,954,980	$1,987,120	$2,019,260	$2,051,400
Installed Cost (Nominal $/Gross MW)	$1,882,000	$1,916,964	$1,951,928	$1,986,891	$2,021,855	$2,056,819	$2,091,783	$2,126,747	$2,161,711	$2,196,674	$2,231,638
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											
High	1	1	1	1.000098277	1.000098277	1.000098277	1.000098277	1.000123552	1.00017586	1.00017586	1.00017586
Instant Cost (Nominal $/Gross MW)	$2,770,000	$2,821,461	$2,872,922	$2,924,671	$2,976,137	$3,027,603	$3,079,069	$3,130,614	$3,182,248	$3,233,719	$3,285,189
Installed Cost (Nominal $/Gross MW)	$3,607,990	$3,675,020	$3,742,049	$3,809,453	$3,876,489	$3,943,524	$4,010,560	$4,077,699	$4,144,954	$4,211,995	$4,279,036
% Cost first year of construction	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Low	1	1	1	0.999926841	0.999926841	0.999926841	0.999926841	0.999908027	0.999869095	0.999869095	0.999869095
Instant Cost (Nominal $/Gross MW)	$945,000	$962,556	$980,112	$997,596	$1,015,151	$1,032,706	$1,050,261	$1,067,795	$1,085,308	$1,102,862	$1,120,416
Installed Cost (Nominal $/Gross MW)	$1,006,000	$1,024,689	$1,043,379	$1,061,991	$1,080,679	$1,099,367	$1,118,055	$1,136,722	$1,155,365	$1,174,052	$1,192,739
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	1	1	1	1	1	1	1	1	1	1
Instant Cost (Nominal $/Gross MW)	$2,083,540	$2,115,680	$2,147,820	$2,179,960	$2,212,100	$2,244,239	$2,276,379	$2,308,519	$2,340,659	$2,372,799
Installed Cost (Nominal $/Gross MW)	$2,266,602	$2,301,566	$2,336,530	$2,371,494	$2,406,457	$2,441,421	$2,476,385	$2,511,349	$2,546,313	$2,581,277
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										
High	1.00017586	1.00024788	1.00024788	1.00024788	1.000277873	1.000346996	1.000346996	1.000346996	1.000346996	1.000490929
Instant Cost (Nominal $/Gross MW)	$3,336,659	$3,388,373	$3,439,847	$3,491,321	$3,542,901	$3,594,625	$3,646,104	$3,697,583	$3,749,061	$3,801,087
Installed Cost (Nominal $/Gross MW)	$4,346,077	$4,413,436	$4,480,482	$4,547,528	$4,614,712	$4,682,083	$4,749,136	$4,816,188	$4,883,241	$4,951,006
% Cost first year of construction	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Low	0.999869095	0.999815497	0.999815497	0.999815497	0.999793179	0.999741746	0.999741746	0.999741746	0.999741746	0.999634668
Instant Cost (Nominal $/Gross MW)	$1,137,969	$1,155,461	$1,173,014	$1,190,567	$1,208,093	$1,225,583	$1,243,135	$1,260,686	$1,278,238	$1,295,651
Installed Cost (Nominal $/Gross MW)	$1,211,426	$1,230,047	$1,248,733	$1,267,419	$1,286,076	$1,304,695	$1,323,379	$1,342,064	$1,360,749	$1,379,286
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Hydro - Developed sites without power**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$17.57	$28.83	$9.88
Variable Cost ($/MWh)	$3.48	$5.54	$1.90

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Name: **Hydro - Developed sites without power**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		**IOU**		**POU**	
	Capital Structure	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Average						
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	**High**	**Low**
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	30	30	30
Economic/Book Life (Years)	30	30	30

Technology Name: Hydro - Developed sites without power

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	30	30	30

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	N	N	N	N	N	N	N	N	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	30%	30%	30%	30%	30%	30%	30%	30%	30%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2005	2005	2005	2005	2005	2005	2005	2005	2005
REPTC In Start Year	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2006	2006	2006	2006	2006	2006	2006	2006	2006
REPI In Start Year ($/kWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Technology Name: **Hydro - Capacity upgrade for developed sites with power**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	80	2	600
Station Service (%)	5.00%	15.00%	5.00%
Net Capacity (MW)	76.00	1.70	570.00
Net Energy (GWh)	202	2	3071
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	7.50%	7.50%	7.50%
Load Center Delivered Capacity (MW)	69.95	1.56	524.61
Net Capacity Factor (NCF)	30.40%	12.50%	61.50%
Planned Percent of Year Operational	100.0%	100.0%	100.0%
Average Percent Output	35.35%	14.81%	70.39%
Net Energy Delivered to Load Center (GWh)	186	2	2826
Forced Outage Rate (FOR)	5.1%	6.7%	3.8%
Scheduled Outage Factor (SOF)	9.40%	9.56%	9.20%
Curtailment (Hours)	0.0	0.0	0.0
Degradation Factors			
Capacity Degradation (%/Year)	2.00%	2.25%	1.75%
Heat Rate Degradation (%/Year)	0	0	0
Emission Factors			
NOX (lbs/MWh)	0	0	0
VOC/ROG (Lbs/MWh)	0	0	0
CO (Lbs/MWh)	0	0	0
CO2 (lbs/MWh)	0	0	0
SOX (lbs/MWh)	0	0	0
PM10 (lbs/MWh)	0	0	0

Technology Name: **Hydro - Capacity upgrade for developed sites with power**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	1	1	1	1	1	1	1	1	1	1
Instant Cost (Nominal $/Gross MW)	$771,000	$785,324	$799,647	$813,971	$828,295	$842,618	$856,942	$871,266	$885,589	$899,913	$914,237
Installed Cost (Nominal $/Gross MW)	$932,000	$949,315	$966,629	$983,944	$1,001,259	$1,018,574	$1,035,888	$1,053,203	$1,070,518	$1,087,832	$1,105,147
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											
High	1	1	1	1.000098277	1.000098277	1.000098277	1.000098277	1.000123552	1.00017586	1.00017586	1.00017586
Instant Cost (Nominal $/Gross MW)	$514,000	$523,549	$533,098	$542,701	$552,251	$561,801	$571,351	$580,915	$590,497	$600,047	$609,598
Installed Cost (Nominal $/Gross MW)	$669,497	$681,935	$694,373	$706,880	$719,320	$731,759	$744,198	$756,656	$769,136	$781,576	$794,016
% Cost first year of construction	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Low	1	1	1	0.999926841	0.999926841	0.999926841	0.999926841	0.999908027	0.999869095	0.999869095	0.999869095
Instant Cost (Nominal $/Gross MW)	$1,638,000	$1,668,431	$1,698,862	$1,729,166	$1,759,594	$1,790,023	$1,820,452	$1,850,845	$1,881,200	$1,911,627	$1,942,054
Installed Cost (Nominal $/Gross MW)	$1,871,000	$1,905,759	$1,940,519	$1,975,134	$2,009,891	$2,044,648	$2,079,405	$2,114,122	$2,148,794	$2,183,549	$2,218,304
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	1	1	1	1	1	1	1	1	1	1
Instant Cost (Nominal $/Gross MW)	$928,560	$942,884	$957,207	$971,531	$985,855	$1,000,178	$1,014,502	$1,028,826	$1,043,149	$1,057,473
Installed Cost (Nominal $/Gross MW)	$1,122,462	$1,139,777	$1,157,091	$1,174,406	$1,191,721	$1,209,035	$1,226,350	$1,243,665	$1,260,980	$1,278,294
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										
High	1.00017586	1.00024788	1.00024788	1.00024788	1.000277873	1.000346996	1.000346996	1.000346996	1.000346996	1.000490929
Instant Cost (Nominal $/Gross MW)	$619,149	$628,745	$638,296	$647,848	$657,419	$667,017	$676,569	$686,122	$695,674	$705,328
Installed Cost (Nominal $/Gross MW)	$806,456	$818,955	$831,396	$843,837	$856,304	$868,805	$881,248	$893,690	$906,132	$918,707
% Cost first year of construction	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Low	0.999869095	0.999815497	0.999815497	0.999815497	0.999793179	0.999741746	0.999741746	0.999741746	0.999741746	0.999634668
Instant Cost (Nominal $/Gross MW)	$1,972,480	$2,002,800	$2,033,225	$2,063,650	$2,094,029	$2,124,344	$2,154,767	$2,185,190	$2,215,613	$2,245,795
Installed Cost (Nominal $/Gross MW)	$2,253,059	$2,287,691	$2,322,445	$2,357,198	$2,391,897	$2,426,525	$2,461,275	$2,496,026	$2,530,776	$2,565,252
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Hydro - Capacity upgrade for developed sites with power**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$12.59	$27.05	$8.77
Variable Cost ($/MWh)	$2.39	$5.00	$1.60

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Name: **Hydro - Capacity upgrade for developed sites with power**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
Average	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	High	Low
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	30	30	30
Economic/Book Life (Years)	30	30	30

Technology Name: **Hydro - Capacity upgrade for developed sites with power**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	30	30	30

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	N	N	N	N	N	N	N	N	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	25%	25%	25%	25%	25%	25%	25%	25%	25%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2005	2005	2005	2005	2005	2005	2005	2005	2005
REPTC In Start Year	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2006	2006	2006	2006	2006	2006	2006	2006	2006
REPI In Start Year ($/kWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Technology Name: **Solar - Parabolic Trough (no storage)**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	250	50	300
Station Service (%)	22.40%	24.00%	20.40%
Net Capacity (MW)	194.00	38.00	238.80
Net Energy (GWh)	459	87	586
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	183.38	35.92	225.73
Net Capacity Factor (NCF)	27.00%	26.00%	28.00%
Planned Percent of Year Operational	27.44%	27.58%	29.10%
Average Percent Output	90.0%	100.0%	80.0%
Net Energy Delivered to Load Center (GWh)	433.73	81.81	553.66
Forced Outage Rate (FOR)	1.60%	1.60%	1.60%
Scheduled Outage Factor (SOF)	2.20%	4.20%	2.20%
Curtailment (Hours)	0	0	0
Degradation Factors			
Capacity Degradation (%/Year)	0.50%	1.00%	0.25%
Heat Rate Degradation (%/Year)	0.00%	0.00%	0.00%
Emission Factors			
NOX (lbs/MWh)	0.000	0.000	0.000
VOC/ROG (Lbs/MWh)	0.000	0.000	0.000
CO (Lbs/MWh)	0.000	0.000	0.000
CO2 (lbs/MWh)	0.000	0.000	0.000
SOX (lbs/MWh)	0.000	0.000	0.000
PM10 (lbs/MWh)	0.000	0.000	0.000

Technology Name: **Solar - Parabolic Trough (no storage)**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average											
Instant Cost (Nominal $/Gross MW)	$3,687,000	$3,331,000	$3,298,000	$3,265,000	$3,232,000	$3,199,000	$3,165,000	$3,077,000	$2,989,000	$2,901,000	$2,813,000
Installed Cost (Nominal $/Gross MW)	$4,018,830	$3,630,790	$3,594,820	$3,558,850	$3,522,880	$3,486,910	$3,449,850	$3,353,930	$3,258,010	$3,162,090	$3,066,170
% Cost of last year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost next to last year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost of previous year of construction											
High											
Instant Cost (Nominal $/Gross MW)	$3,900,000	$3,562,000	$3,527,000	$3,492,000	$3,457,000	$3,422,000	$3,389,000	$3,355,000	$3,321,000	$3,287,000	$3,253,000
Installed Cost (Nominal $/Gross MW)	$4,251,000	$3,882,580	$3,844,430	$3,806,280	$3,768,130	$3,729,980	$3,694,010	$3,656,950	$3,619,890	$3,582,830	$3,545,770
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost third year of construction											
Low											
Instant Cost (Nominal $/Gross MW)	$3,408,000	$2,876,000	$2,810,000	$2,744,000	$2,678,000	$2,612,000	$2,546,000	$2,481,000	$2,416,000	$2,351,000	$2,286,000
Installed Cost (Nominal $/Gross MW)	$3,714,720	$3,134,840	$3,062,900	$2,990,960	$2,919,020	$2,847,080	$2,775,140	$2,704,290	$2,633,440	$2,562,590	$2,491,740
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average										
Instant Cost (Nominal $/Gross MW)	$2,725,000	$2,692,000	$2,659,000	$2,626,000	$2,593,000	$2,560,000	$2,527,000	$2,494,000	$2,461,000	$2,428,000
Installed Cost (Nominal $/Gross MW)	$2,970,250	$2,934,280	$2,898,310	$2,862,340	$2,826,370	$2,790,400	$2,754,430	$2,718,460	$2,682,490	$2,646,520
% Cost of last year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost next to last year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost of previous year of construction										
High										
Instant Cost (Nominal $/Gross MW)	$3,220,000	$3,190,000	$3,160,000	$3,130,000	$3,100,000	$3,070,000	$3,040,000	$3,010,000	$2,980,000	$2,950,000
Installed Cost (Nominal $/Gross MW)	$3,509,800	$3,477,100	$3,444,400	$3,411,700	$3,379,000	$3,346,300	$3,313,600	$3,280,900	$3,248,200	$3,215,500
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost third year of construction										
Low										
Instant Cost (Nominal $/Gross MW)	$2,221,000	$2,188,000	$2,155,000	$2,122,000	$2,089,000	$2,056,000	$2,023,000	$1,990,000	$1,957,000	$1,924,000
Installed Cost (Nominal $/Gross MW)	$2,420,890	$2,384,920	$2,348,950	$2,312,980	$2,277,010	$2,241,040	$2,205,070	$2,169,100	$2,133,130	$2,097,160
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Solar - Parabolic Trough (no storage)**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$68.0	$92.00	$60.00
Variable Cost ($/MWh)	$0.00	$0.00	$0.00

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Low	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Heat Rate (Btu/kWh)											
Nominal	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0	0

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Low	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Heat Rate (Btu/kWh)										
Nominal	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0

Technology Name: **Solar - Parabolic Trough (no storage)**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital
Average						
Equity	40.0%	15.2%	50.0%	11.7%	0.0%	0.0%
Debt Financed:	60.0%	6.7%	50.0%	5.9%	100.0%	4.3%
Discount Rate (WACC)	9.7%		8.6%		4.3%	
High						
Equity	60.0%	18.0%	55.0%	15.0%	0.0%	0.0%
Debt Financed:	40.0%	10.0%	45.0%	9.0%	100.0%	7.0%
Discount Rate (WACC)	14.4%		11.9%		7.0%	
Low						
Equity	35.0%	14.0%	50.0%	10.0%	0.0%	0.0%
Debt Financed:	65.0%	6.0%	50.0%	5.9%	100.0%	4.0%
Discount Rate (WACC)	8.5%		7.7%		4.0%	

	Average	High	Low
Loan/Debt Term (Years)	15	20	10
Equipment Life (Years):	20	20	20
Economic/Book Life (Years)	20	20	20

Technology Name: **Solar - Parabolic Trough (no storage)**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	N	N	N	N	N	N	N	N	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
TDMA	Y	Y	N	Y	Y	N	Y	Y	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	30%	30%	30%	30%	30%	30%	30%	30%	30%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Solar - Parabolic Trough (Storage Case - 6 hour molten salt)**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	250	50	300
Station Service (%)	29.40%	31.00%	27.40%
Net Capacity (MW)	176.50	34.50	217.80
Net Energy (GWh)	1005	181	1336
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	166.84	32.61	205.88
Net Capacity Factor (NCF)	65.00%	60.00%	70.00%
Planned Percent of Year Operational	66.06%	63.65%	72.74%
Average Percent Output	90.0%	100.0%	80.0%
Net Energy Delivered to Load Center (GWh)	949.97	171.40	1262.43
Forced Outage Rate (FOR)	1.60%	1.60%	1.60%
Scheduled Outage Factor (SOF)	2.20%	4.20%	2.20%
Curtailment (Hours)	0	0	0
Degradation Factors			
Capacity Degradation (%/Year)	0.50%	1.00%	0.25%
Heat Rate Degradation (%/Year)	0.00%	0.00%	0.00%
Emission Factors			
NOX (lbs/MWh)	0.000	0.000	0.000
VOC/ROG (Lbs/MWh)	0.000	0.000	0.000
CO (Lbs/MWh)	0.000	0.000	0.000
CO2 (lbs/MWh)	0.000	0.000	0.000
SOX (lbs/MWh)	0.000	0.000	0.000
PM10 (lbs/MWh)	0.000	0.000	0.000

Note: Parabolic Trough with Storage assumes 57% greater solar area
due to recharge of thermal storage system per NREL, 2/2003
Also assumes that the solar field direct cost is 58% of the total instant cost.

Technology Name: Solar - Parabolic Trough (Storage Case - 6 hour molten salt)

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average											
Instant Cost (Nominal $/Gross MW)	$5,406,000	$ 4,932,000	$ 4,899,000	$ 4,866,000	$ 4,833,000	$ 4,800,000	$4,711,350	$4,623,350	$4,535,350	$4,447,350	$4,359,350
Installed Cost (Nominal $/Gross MW)	$5,892,540	$5,375,880	$5,339,910	$5,303,940	$5,267,970	$5,232,000	$5,135,372	$5,039,452	$4,943,532	$4,847,612	$4,751,692
% Cost of last year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost next to last year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost of previous year of construction											
High											
Instant Cost (Nominal $/Gross MW)	$5,789,300	$5,340,000	$5,305,000	$5,270,000	$5,235,000	$5,200,000	$5,109,400	$5,075,400	$5,041,400	$5,007,400	$4,973,400
Installed Cost (Nominal $/Gross MW)	$6,310,337	$5,820,600	$5,782,450	$5,744,300	$5,706,150	$5,668,000	$5,569,246	$5,532,186	$5,495,126	$5,458,066	$5,421,006
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost third year of construction											
Low											
Instant Cost (Nominal $/Gross MW)	$5,034,700	$4,327,000	$4,261,000	$4,195,000	$4,129,000	$4,063,000	$3,888,000	$3,823,000	$3,758,000	$3,693,000	$3,628,000
Installed Cost (Nominal $/Gross MW)	$5,487,823	$4,716,430	$4,644,490	$4,572,550	$4,500,610	$4,428,670	$4,237,920	$4,167,070	$4,096,220	$4,025,370	$3,954,520
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average										
Instant Cost (Nominal $/Gross MW)	$4,126,000	$4,093,000	$4,060,000	$4,027,000	$3,994,000	$3,961,000	$3,928,000	$3,895,000	$3,862,000	$3,829,000
Installed Cost (Nominal $/Gross MW)	$4,497,340	$4,461,370	$4,425,400	$4,389,430	$4,353,460	$4,317,490	$4,281,520	$4,245,550	$4,209,580	$4,173,610
% Cost of last year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost next to last year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost of previous year of construction										
High										
Instant Cost (Nominal $/Gross MW)	$4,885,000	$4,855,000	$4,825,000	$4,795,000	$4,765,000	$4,735,000	$4,705,000	$4,675,000	$4,645,000	$4,615,000
Installed Cost (Nominal $/Gross MW)	$5,324,650	$5,291,950	$5,259,250	$5,226,550	$5,193,850	$5,161,150	$5,128,450	$5,095,750	$5,063,050	$5,030,350
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost third year of construction										
Low										
Instant Cost (Nominal $/Gross MW)	$3,455,000	$3,422,000	$3,389,000	$3,356,000	$3,323,000	$3,290,000	$3,257,000	$3,224,000	$3,191,000	$3,158,000
Installed Cost (Nominal $/Gross MW)	$3,765,950	$3,729,980	$3,694,010	$3,658,040	$3,622,070	$3,586,100	$3,550,130	$3,514,160	$3,478,190	$3,442,220
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Solar - Parabolic Trough (Storage Case - 6 hour molten salt)**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$68.0	$92.00	$60.00
Variable Cost ($/MWh)	$10.30	$23.30	$5.70

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Low	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Heat Rate (Btu/kWh)											
Nominal	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0	0

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Low	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Heat Rate (Btu/kWh)										
Nominal	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0

Technology Name: **Solar - Parabolic Trough (Storage Case - 6 hour molten salt)**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital
Average						
Equity	40.0%	15.2%	50.0%	11.7%	0.0%	0.0%
Debt Financed:	60.0%	6.7%	50.0%	5.9%	100.0%	4.3%
Discount Rate (WACC)	9.7%		8.6%		4.3%	
High						
Equity	60.0%	18.0%	55.0%	15.0%	0.0%	0.0%
Debt Financed:	40.0%	10.0%	45.0%	9.0%	100.0%	7.0%
Discount Rate (WACC)	14.4%		11.9%		7.0%	
Low						
Equity	35.0%	14.0%	50.0%	10.0%	0.0%	0.0%
Debt Financed:	65.0%	6.0%	50.0%	5.9%	100.0%	4.0%
Discount Rate (WACC)	8.5%		7.7%		4.0%	

	Average	High	Low
Loan/Debt Term (Years)	15	20	10
Equipment Life (Years):	20	20	20
Economic/Book Life (Years)	20	20	20

Technology Name: **Solar - Parabolic Trough (Storage Case - 6 hour molten salt)**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	N	N	N	N	N	N	N	N	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
TDMA	Y	Y	N	Y	Y	N	Y	Y	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	30%	30%	30%	30%	30%	30%	30%	30%	30%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Solar - Photovoltaic (1-axis)**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	25	50	15
Station Service (%)	22.40%	24.00%	20.00%
Net Capacity (MW)	19.40	38.00	12.00
Net Energy (GWh)	46	87	29
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	18.34	35.92	11.34
Net Capacity Factor (NCF)	27.00%	26.00%	28.00%
Planned Percent of Year Operational	27.55%	28.26%	28.28%
Average Percent Output	90.0%	100.0%	80.0%
Net Energy Delivered to Load Center (GWh)	43.37	81.81	27.82
Forced Outage Rate (FOR)	2.00%	8.00%	1.00%
Scheduled Outage Factor (SOF)	0.00%	0.00%	0.00%
Curtailment (Hours)	0	0	0
Degradation Factors			
Capacity Degradation (%/Year)	0.50%	1.00%	0.25%
Heat Rate Degradation (%/Year)	0.00%	0.00%	0.00%
Emission Factors			
NOX (lbs/MWh)	0.000	0.000	0.000
VOC/ROG (Lbs/MWh)	0.000	0.000	0.000
CO (Lbs/MWh)	0.000	0.000	0.000
CO2 (lbs/MWh)	0.000	0.000	0.000
SOX (lbs/MWh)	0.000	0.000	0.000
PM10 (lbs/MWh)	0.000	0.000	0.000

Technology Name: **Solar - Photovoltaic (1-axis)**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	0.955246582	0.919362587	0.889603159	0.860093106	0.832455091	0.808933193	0.787880134	0.769425285	0.753040763	0.736033428
Instant Cost (Nominal $/Gross MW)	$4,550,000	$4,550,000	$4,355,000	$4,160,000	$3,965,000	$3,770,000	$3,575,000	$3,380,000	$3,185,000	$2,990,000	$2,795,000
Installed Cost (Nominal $/Gross MW)	$4,959,500	$4,959,500	$4,746,950	$4,534,400	$4,321,850	$4,109,300	$3,896,750	$3,684,200	$3,471,650	$3,259,100	$3,046,550
% Cost of last year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost next to last year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost of previous year of construction											
High	1	0.965860094	0.938206754	0.91507518	0.891952274	0.870121997	0.851404823	0.834540533	0.819667882	0.806391416	0.792536317
Instant Cost (Nominal $/Gross MW)	$5,005,000	$5,005,000	$4,790,500	$4,576,000	$4,361,500	$4,147,000	$3,932,500	$3,718,000	$3,503,500	$3,289,000	$3,074,500
Installed Cost (Nominal $/Gross MW)	$5,455,450	$5,455,450	$5,221,645	$4,987,840	$4,754,035	$4,520,230	$4,286,425	$4,052,620	$3,818,815	$3,585,010	$3,351,205
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost third year of construction											
Low	1	0.941541914	0.895287967	0.857357495	0.820138277	0.78564355	0.756569058	0.730771321	0.708335425	0.688558179	0.668172354
Instant Cost (Nominal $/Gross MW)	$4,095,000	$4,095,000	$3,919,500	$3,744,000	$3,568,500	$3,393,000	$3,217,500	$3,042,000	$2,866,500	$2,691,000	$2,515,500
Installed Cost (Nominal $/Gross MW)	$4,463,550	$4,463,550	$4,272,255	$4,080,960	$3,889,665	$3,698,370	$3,507,075	$3,315,780	$3,124,485	$2,933,190	$2,741,895
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.720871631	0.707222058	0.694832011	0.683505687	0.673088501	0.663456374	0.654508386	0.646161325	0.638345911	0.631003863
Instant Cost (Nominal $/Gross MW)	$2,600,000	$2,470,000	$2,340,000	$2,210,000	$2,080,000	$1,950,000	$1,820,000	$1,690,000	$1,560,000	$1,430,000
Installed Cost (Nominal $/Gross MW)	$2,834,000	$2,692,300	$2,550,600	$2,408,900	$2,267,200	$2,125,500	$1,983,800	$1,842,100	$1,700,400	$1,558,700
% Cost of last year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost next to last year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost of previous year of construction										
High	0.780119434	0.768886996	0.758645666	0.749244966	0.7405656	0.732511443	0.725004028	0.717978434	0.711380442	0.705164297
Instant Cost (Nominal $/Gross MW)	$2,860,000	$2,717,000	$2,574,000	$2,431,000	$2,288,000	$2,145,000	$2,002,000	$1,859,000	$1,716,000	$1,573,000
Installed Cost (Nominal $/Gross MW)	$3,117,400	$2,961,530	$2,805,660	$2,649,790	$2,493,920	$2,338,050	$2,182,180	$2,026,310	$1,870,440	$1,714,570
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
% Cost third year of construction										
Low	0.650123508	0.633976938	0.619405178	0.606155975	0.594031252	0.582872829	0.572552651	0.562965602	0.554024534	0.545656418
Instant Cost (Nominal $/Gross MW)	$2,340,000	$2,223,000	$2,106,000	$1,989,000	$1,872,000	$1,755,000	$1,638,000	$1,521,000	$1,404,000	$1,287,000
Installed Cost (Nominal $/Gross MW)	$2,550,600	$2,423,070	$2,295,540	$2,168,010	$2,040,480	$1,912,950	$1,785,420	$1,657,890	$1,530,360	$1,402,830
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Solar - Photovoltaic (1-axis)**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$68.0	$92.00	$60.00
Variable Cost ($/MWh)	$0.00	$0.00	$0.00

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Low	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Heat Rate (Btu/kWh)											
Nominal	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0	0

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Low	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Heat Rate (Btu/kWh)										
Nominal	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0
Low	0	0	0	0	0	0	0	0	0	0

Technology Name: **Solar - Photovoltaic (1-axis)**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
Average	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Equity	40.0%	15.2%	50.0%	11.7%	0.0%	0.0%
Debt Financed:	60.0%	6.7%	50.0%	5.9%	100.0%	4.3%
Discount Rate (WACC)	9.7%		8.6%		4.3%	
High						
Equity	60.0%	18.0%	55.0%	15.0%	0.0%	0.0%
Debt Financed:	40.0%	10.0%	45.0%	9.0%	100.0%	7.0%
Discount Rate (WACC)	14.4%		11.9%		7.0%	
Low						
Equity	35.0%	14.0%	50.0%	10.0%	0.0%	0.0%
Debt Financed:	65.0%	6.0%	50.0%	5.9%	100.0%	4.0%
Discount Rate (WACC)	8.5%		7.7%		4.0%	

	Average	High	Low
Loan/Debt Term (Years)	15	20	10
Equipment Life (Years):	20	20	20
Economic/Book Life (Years)	20	20	20

Technology Name: **Solar - Photovoltaic (1-axis)**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	N	N	N	N	N	N	N	N	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
TDMA	Y	Y	N	Y	Y	N	Y	Y	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	30%	30%	30%	30%	30%	30%	30%	30%	30%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Onshore Wind - Class 5**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	100	50	200
Station Service (%)	0.10%	0.10%	0.10%
Net Capacity (MW)	99.90	49.95	199.80
Net Energy (GWh)	368	175	770
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	94.43	47.22	188.86
Net Capacity Factor (NCF)	42%	40%	44%
Planned Percent of Year Operational	100.0%	100.0%	100.0%
Average Percent Output	43.46%	41.88%	45.01%
Net Energy Delivered to Load Center (GWh)	347	165	728
Forced Outage Rate (FOR)	2.0%	2.7%	1.3%
Scheduled Outage Factor (SOF)	1.39%	1.83%	0.96%
Curtailment (Hours)	0.0	0.0	0.0
Degradation Factors			
Capacity Degradation (%/Year)	1.00%	1.00%	1.00%
Heat Rate Degradation (%/Year)	0	0	0
Emission Factors			
NOX (lbs/MWh)	0	0	0
VOC/ROG (Lbs/MWh)	0	0	0
CO (Lbs/MWh)	0	0	0
CO2 (lbs/MWh)	0	0	0
SOX (lbs/MWh)	0	0	0
PM10 (lbs/MWh)	0	0	0

Technology Name: Onshore Wind - Class 5

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	0.99855948	0.99855948	0.992858959	0.992858959	0.992858959	0.992426353	0.98644194	0.98644194	0.98644194	0.986325258
Instant Cost (Nominal $/Gross MW)	$1,990,000	$2,042,773	$2,099,971	$2,146,446	$2,206,547	$2,268,330	$2,330,827	$2,381,642	$2,448,328	$2,516,881	$2,587,047
Installed Cost (Nominal $/Gross MW)	$2,331,817	$2,393,655	$2,460,677	$2,515,136	$2,585,559	$2,657,955	$2,731,187	$2,790,730	$2,868,871	$2,949,199	$3,031,418
% Cost first year of construction	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
% Cost second year of construction	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
% Cost third year of construction											
High	1	0.999680986	0.999680986	0.998415036	0.998415036	0.998415036	0.998318733	0.996983179	0.996983179	0.996983179	0.996957076
Instant Cost (Nominal $/Gross MW)	$3,025,000	$3,108,708	$3,195,752	$3,281,073	$3,372,943	$3,467,385	$3,564,128	$3,659,022	$3,761,475	$3,866,796	$3,974,962
Installed Cost (Nominal $/Gross MW)	$3,784,917	$3,889,653	$3,998,564	$4,105,318	$4,220,267	$4,338,434	$4,459,480	$4,578,213	$4,706,403	$4,838,182	$4,973,521
% Cost first year of construction	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	1	0.997952035	0.997952035	0.98985993	0.98985993	0.98985993	0.989246628	0.980774168	0.980774168	0.980774168	0.98060919
Instant Cost (Nominal $/Gross MW)	$1,440,000	$1,477,288	$1,518,652	$1,548,516	$1,591,874	$1,636,446	$1,681,225	$1,713,497	$1,761,475	$1,810,796	$1,861,185
Installed Cost (Nominal $/Gross MW)	$1,644,029	$1,686,601	$1,733,826	$1,767,920	$1,817,422	$1,868,310	$1,919,432	$1,956,277	$2,011,053	$2,067,362	$2,124,891
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.981196149	0.974971867	0.971135258	0.96493117	0.962109094	0.956894598	0.950522181	0.949490099	0.942596731	0.940398379
Instant Cost (Nominal $/Gross MW)	$2,614,772	$2,639,756	$2,671,438	$2,696,841	$2,731,977	$2,760,645	$2,786,137	$2,827,641	$2,852,026	$2,890,901
Installed Cost (Nominal $/Gross MW)	$3,063,904	$3,093,180	$3,130,304	$3,160,071	$3,201,242	$3,234,834	$3,264,704	$3,313,338	$3,341,912	$3,387,463
% Cost first year of construction	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
% Cost second year of construction	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
% Cost third year of construction										
High	0.995807266	0.994405643	0.993538217	0.99212986	0.991486901	0.990294999	0.98883154	0.988593799	0.98700072	0.986490767
Instant Cost (Nominal $/Gross MW)	$4,033,904	$4,092,677	$4,154,533	$4,215,022	$4,279,687	$4,342,935	$4,405,902	$4,475,320	$4,539,598	$4,609,848
Installed Cost (Nominal $/Gross MW)	$5,047,269	$5,120,808	$5,198,202	$5,273,887	$5,354,797	$5,433,934	$5,512,718	$5,599,575	$5,680,000	$5,767,898
% Cost first year of construction	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	0.973365236	0.964595993	0.959202437	0.950499672	0.946548815	0.939261478	0.930378667	0.92894236	0.919366048	0.916318284
Instant Cost (Nominal $/Gross MW)	$1,876,995	$1,889,846	$1,909,348	$1,922,297	$1,944,935	$1,960,841	$1,973,374	$2,001,852	$2,012,915	$2,038,342
Installed Cost (Nominal $/Gross MW)	$2,142,941	$2,157,613	$2,179,877	$2,194,661	$2,220,507	$2,238,667	$2,252,975	$2,285,489	$2,298,119	$2,327,149
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
% Cost third year of construction										

Technology Name: **Onshore Wind - Class 5**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$13.70	$17.13	$10.28
Variable Cost ($/MWh)	$5.50	$7.66	$4.82

Start Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Start Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Name: **Onshore Wind - Class 5**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
Average	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	High	Low
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	30	30	30
Economic/Book Life (Years)	30	30	30

Technology Name: **Onshore Wind - Class 5**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	30	30	30

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	25%	25%	25%	25%	25%	25%	25%	25%	25%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2005	2005	2005	2005	2005	2005	2005	2005	2005
REPTC In Start Year	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Onshore Wind - Class 3/4**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	50	30	100
Station Service (%)	0.10%	0.10%	0.10%
Net Capacity (MW)	49.95	29.97	99.90
Net Energy (GWh)	162	108	298
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	47.22	28.33	94.43
Net Capacity Factor (NCF)	37%	41%	34%
Planned Percent of Year Operational	100.0%	100.0%	100.0%
Average Percent Output	38.29%	42.92%	34.78%
Net Energy Delivered to Load Center (GWh)	153	102	281
Forced Outage Rate (FOR)	2.0%	2.7%	1.3%
Scheduled Outage Factor (SOF)	1.39%	1.83%	0.96%
Curtailment (Hours)	0.0	0.0	0.0
Degradation Factors			
Capacity Degradation (%/Year)	1.00%	1.00%	1.00%
Heat Rate Degradation (%/Year)	0	0	0
Emission Factors			
NOX (lbs/MWh)	0	0	0
VOC/ROG (Lbs/MWh)	0	0	0
CO (Lbs/MWh)	0	0	0
CO2 (lbs/MWh)	0	0	0
SOX (lbs/MWh)	0	0	0
PM10 (lbs/MWh)	0	0	0

Technology Name: **Onshore Wind - Class 3/4**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	0.99855948	0.99855948	0.992858959	0.992858959	0.992858959	0.992426353	0.98644194	0.98644194	0.98644194	0.986325258
Instant Cost (Nominal $/Gross MW)	$1,990,000	$2,042,773	$2,099,971	$2,146,446	$2,206,547	$2,268,330	$2,330,827	$2,381,642	$2,448,328	$2,516,881	$2,587,047
Installed Cost (Nominal $/Gross MW)	$2,331,817	$2,393,655	$2,460,677	$2,515,136	$2,585,559	$2,657,955	$2,731,187	$2,790,730	$2,868,871	$2,949,199	$3,031,418
% Cost first year of construction	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
% Cost second year of construction	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
% Cost third year of construction											
High	1	0.999680986	0.999680986	0.998415036	0.998415036	0.998415036	0.998318733	0.996983179	0.996983179	0.996983179	0.996957076
Instant Cost (Nominal $/Gross MW)	$3,025,000	$3,108,708	$3,195,752	$3,281,073	$3,372,943	$3,467,385	$3,564,128	$3,659,022	$3,761,475	$3,866,796	$3,974,962
Installed Cost (Nominal $/Gross MW)	$3,784,917	$3,889,653	$3,998,564	$4,105,318	$4,220,267	$4,338,434	$4,459,480	$4,578,213	$4,706,403	$4,838,182	$4,973,521
% Cost first year of construction	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	1	0.997952035	0.997952035	0.98985993	0.98985993	0.98985993	0.989246628	0.980774168	0.980774168	0.980774168	0.98060919
Instant Cost (Nominal $/Gross MW)	$1,440,000	$1,477,288	$1,518,652	$1,548,516	$1,591,874	$1,636,446	$1,681,225	$1,713,497	$1,761,475	$1,810,796	$1,861,185
Installed Cost (Nominal $/Gross MW)	$1,644,029	$1,686,601	$1,733,826	$1,767,920	$1,817,422	$1,868,310	$1,919,432	$1,956,277	$2,011,053	$2,067,362	$2,124,891
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.981196149	0.974971867	0.971135258	0.96493117	0.962109094	0.956894598	0.950522181	0.949490099	0.942596731	0.940398379
Instant Cost (Nominal $/Gross MW)	$2,614,772	$2,639,756	$2,671,438	$2,696,841	$2,731,977	$2,760,645	$2,786,137	$2,827,641	$2,852,026	$2,890,901
Installed Cost (Nominal $/Gross MW)	$3,063,904	$3,093,180	$3,130,304	$3,160,071	$3,201,242	$3,234,834	$3,264,704	$3,313,338	$3,341,912	$3,387,463
% Cost first year of construction	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
% Cost second year of construction	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
% Cost third year of construction										
High	0.995807266	0.994405643	0.993538217	0.99212986	0.991486901	0.990294999	0.98883154	0.988593799	0.98700072	0.986490767
Instant Cost (Nominal $/Gross MW)	$4,033,904	$4,092,677	$4,154,533	$4,215,022	$4,279,687	$4,342,935	$4,405,902	$4,475,320	$4,539,598	$4,609,848
Installed Cost (Nominal $/Gross MW)	$5,047,269	$5,120,808	$5,198,202	$5,273,887	$5,354,797	$5,433,934	$5,512,718	$5,599,575	$5,680,000	$5,767,898
% Cost first year of construction	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	0.973365236	0.964595993	0.959202437	0.950499672	0.946548815	0.939261478	0.930378667	0.92894236	0.919366048	0.916318284
Instant Cost (Nominal $/Gross MW)	$1,876,995	$1,889,846	$1,909,348	$1,922,297	$1,944,935	$1,960,841	$1,973,374	$2,001,852	$2,012,915	$2,038,342
Installed Cost (Nominal $/Gross MW)	$2,142,941	$2,157,613	$2,179,877	$2,194,661	$2,220,507	$2,238,667	$2,252,975	$2,285,489	$2,298,119	$2,327,149
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
% Cost third year of construction										

Technology Name: **Onshore Wind - Class 3/4**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$13.70	$17.13	$10.28
Variable Cost ($/MWh)	$5.50	$7.66	$4.82

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Name: **Onshore Wind - Class 3/4**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
Average	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	High	Low
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	30	30	30
Economic/Book Life (Years)	30	30	30

Technology Name: **Onshore Wind - Class 3/4**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	30	30	30

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	25%	25%	25%	25%	25%	25%	25%	25%	25%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPI In Start Year ($/kWh)	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021

Technology Name: **Offshore Wind - Class 5**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	100	50	350
Station Service (%)	0.10%	0.10%	0.10%
Net Capacity (MW)	99.90	49.95	349.65
Net Energy (GWh)	394	184	1470
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	94.43	47.22	330.51
Net Capacity Factor (NCF)	45%	42%	48%
Planned Percent of Year Operational	100.0%	100.0%	100.0%
Average Percent Output	47.15%	44.63%	49.60%
Net Energy Delivered to Load Center (GWh)	372	174	1390
Forced Outage Rate (FOR)	2.0%	2.7%	1.3%
Scheduled Outage Factor (SOF)	2.62%	3.29%	1.96%
Curtailment (Hours)	0.0	0.0	0.0
Degradation Factors			
Capacity Degradation (%/Year)	1.00%	1.00%	1.00%
Heat Rate Degradation (%/Year)	0	0	0
Emission Factors			
NOX (lbs/MWh)	0	0	0
VOC/ROG (Lbs/MWh)	0	0	0
CO (Lbs/MWh)	0	0	0
CO2 (lbs/MWh)	0	0	0
SOX (lbs/MWh)	0	0	0
PM10 (lbs/MWh)	0	0	0

Technology Name: **Offshore Wind - Class 5**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	0.931857019	0.891021848	0.85855458	0.826608704	0.798099338	0.772699122	0.748455365	0.72529479	0.70181175	0.67858922
Instant Cost (Nominal $/Gross MW)	$5,587,937	$5,284,651	$5,134,323	$5,022,499	$4,912,766	$4,816,651	$4,737,886	$4,663,611	$4,592,277	$4,515,023	$4,435,474
Installed Cost (Nominal $/Gross MW)	$6,547,763	$6,192,382	$6,016,232	$5,885,201	$5,756,620	$5,643,994	$5,551,701	$5,464,668	$5,381,081	$5,290,557	$5,197,344
% Cost first year of construction	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
% Cost second year of construction	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
% Cost third year of construction											
High	1.00000	0.97506	0.95955	0.94689	0.93413	0.92247	0.91186	0.90151	0.89143	0.88099	0.87045
Instant Cost (Nominal $/Gross MW)	$5,587,937	$5,529,669	$5,529,209	$5,539,259	$5,551,790	$5,567,248	$5,591,138	$5,617,310	$5,644,175	$5,667,760	$5,689,522
Installed Cost (Nominal $/Gross MW)	$6,991,695	$6,918,789	$6,918,214	$6,930,788	$6,946,467	$6,965,809	$6,995,700	$7,028,447	$7,062,061	$7,091,570	$7,118,800
% Cost first year of construction	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	1	0.920587662	0.873472411	0.836275958	0.799912775	0.767664996	0.739100692	0.711987429	0.686226537	0.660251412	0.634711382
Instant Cost (Nominal $/Gross MW)	$5,587,937	$5,220,742	$5,033,198	$4,892,170	$4,754,105	$4,632,975	$4,531,874	$4,436,380	$4,344,912	$4,247,649	$4,148,674
Installed Cost (Nominal $/Gross MW)	$6,379,675	$5,960,453	$5,746,336	$5,585,327	$5,427,700	$5,289,407	$5,173,981	$5,064,958	$4,960,530	$4,849,486	$4,736,487
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.656668505	0.638029178	0.62220396	0.608458307	0.596311246	0.585431062	0.575684613	0.56685994	0.558799059	0.551381156
Instant Cost (Nominal $/Gross MW)	$4,360,868	$4,304,879	$4,265,274	$4,237,783	$4,219,632	$4,208,924	$4,205,074	$4,206,864	$4,213,394	$4,223,982
Installed Cost (Nominal $/Gross MW)	$5,109,923	$5,044,318	$4,997,909	$4,965,696	$4,944,427	$4,931,880	$4,927,369	$4,929,466	$4,937,118	$4,949,524
% Cost first year of construction	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
% Cost second year of construction	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
% Cost third year of construction										
High	0.86028	0.85146	0.84384	0.83712	0.83111	0.82565	0.82070	0.81618	0.81201	0.80813
Instant Cost (Nominal $/Gross MW)	$5,713,030	$5,744,936	$5,784,632	$5,830,392	$5,881,086	$5,935,941	$5,994,794	$6,057,135	$6,122,590	$6,190,876
Installed Cost (Nominal $/Gross MW)	$7,148,213	$7,188,134	$7,237,802	$7,295,057	$7,358,487	$7,427,121	$7,500,759	$7,578,761	$7,660,659	$7,746,100
% Cost first year of construction	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
% Cost second year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
% Cost third year of construction	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%
Low	0.610740874	0.590466668	0.573333261	0.558512108	0.545462544	0.533812803	0.523408613	0.514014553	0.505455562	0.497598059
Instant Cost (Nominal $/Gross MW)	$4,055,867	$3,983,968	$3,930,260	$3,889,918	$3,859,815	$3,837,817	$3,823,225	$3,814,680	$3,811,179	$3,811,964
Installed Cost (Nominal $/Gross MW)	$4,630,531	$4,548,444	$4,487,127	$4,441,069	$4,406,701	$4,381,586	$4,364,926	$4,355,170	$4,351,174	$4,352,070
% Cost first year of construction	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
% Cost second year of construction	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
% Cost third year of construction										

Technology Name: **Offshore Wind - Class 5**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$27.40	$34.25	$20.55
Variable Cost ($/MWh)	$11.00	$15.32	$9.64

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Name: **Offshore Wind - Class 5**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
Average	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	High	Low
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	30	30	30
Economic/Book Life (Years)	30	30	30

Technology Name: Offshore Wind - Class 5

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	30	30	30

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	Y	Y	Y	Y	Y	Y	Y	Y	Y
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	25%	25%	25%	25%	25%	25%	25%	25%	25%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2009	2009	2009	2009	2009	2009	2009	2009	2009
REPTC In Start Year	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2006	2006	2006	2006	2006	2006	2006	2006	2006
REPI In Start Year ($/kWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Technology Name: **Ocean Wave**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	40	5	100
Station Service (%)	1.00%	1.00%	1.00%
Net Capacity (MW)	39.60	4.95	99.00
Net Energy (GWh)	90	9	260
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	37.43	4.68	93.58
Net Capacity Factor (NCF)	26.00%	21.00%	30.00%
Planned Percent of Year Operational	100.0%	100.0%	100.0%
Average Percent Output	30.24%	24.87%	34.34%
Net Energy Delivered to Load Center (GWh)	85	9	246
Forced Outage Rate (FOR)	5.1%	6.7%	3.8%
Scheduled Outage Factor (SOF)	9.40%	9.56%	9.20%
Curtailment (Hours)	0.0	0.0	0.0
Degradation Factors			
Capacity Degradation (%/Year)	1.00%	1.00%	1.00%
Heat Rate Degradation (%/Year)	0	0	0
Emission Factors			
NOX (lbs/MWh)	0	0	0
VOC/ROG (Lbs/MWh)	0	0	0
CO (Lbs/MWh)	0	0	0
CO2 (lbs/MWh)	0	0	0
SOX (lbs/MWh)	0	0	0
PM10 (lbs/MWh)	0	0	0

Technology Name: **Ocean Wave**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average											
Instant Cost (Nominal $/Gross MW)	$2,586,645	$2,625,140	$2,667,351	$2,707,929	$2,751,132	$2,793,660	$2,838,308	$2,884,309	$2,930,886	$2,978,000	$3,029,989
Installed Cost (Nominal $/Gross MW)	$2,696,059	$2,736,182	$2,780,179	$2,822,473	$2,867,504	$2,911,831	$2,958,367	$3,006,314	$3,054,861	$3,103,968	$3,158,157
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											
High											
Instant Cost (Nominal $/Gross MW)	$2,854,169	$2,896,645	$2,943,222	$2,987,997	$3,035,669	$3,082,595	$3,131,861	$3,182,619	$3,234,013	$3,286,000	$3,029,989
Installed Cost (Nominal $/Gross MW)	$3,485,311	$3,537,179	$3,594,056	$3,648,732	$3,706,945	$3,764,248	$3,824,408	$3,886,391	$3,949,149	$4,012,632	$3,700,010
% Cost first year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost second year of construction	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
% Cost third year of construction											
Low											
Instant Cost (Nominal $/Gross MW)	$2,365,156	$2,400,354	$2,438,951	$2,476,055	$2,515,559	$2,554,445	$2,595,270	$2,637,332	$2,679,920	$2,723,000	$3,029,989
Installed Cost (Nominal $/Gross MW)	$2,450,431	$2,486,898	$2,526,886	$2,565,328	$2,606,256	$2,646,544	$2,688,841	$2,732,419	$2,776,543	$2,821,176	$3,139,234
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction											
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average										
Instant Cost (Nominal $/Gross MW)	$3,081,979	$3,133,968	$3,185,958	$3,237,947	$3,289,936	$3,341,926	$3,393,915	$3,445,904	$3,497,894	$3,549,883
Installed Cost (Nominal $/Gross MW)	$3,212,345	$3,266,534	$3,320,722	$3,374,911	$3,429,099	$3,483,288	$3,537,476	$3,591,665	$3,645,853	$3,700,042
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										
High										
Instant Cost (Nominal $/Gross MW)	$3,081,979	$3,133,968	$3,185,958	$3,237,947	$3,289,936	$3,341,926	$3,393,915	$3,445,904	$3,497,894	$3,549,883
Installed Cost (Nominal $/Gross MW)	$3,763,496	$3,826,982	$3,890,468	$3,953,953	$4,017,439	$4,080,925	$4,144,411	$4,207,896	$4,271,382	$4,334,868
% Cost first year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost second year of construction	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
% Cost third year of construction										
Low										
Instant Cost (Nominal $/Gross MW)	$3,081,979	$3,133,968	$3,185,958	$3,237,947	$3,289,936	$3,341,926	$3,393,915	$3,445,904	$3,497,894	$3,549,883
Installed Cost (Nominal $/Gross MW)	$3,193,098	$3,246,962	$3,300,826	$3,354,690	$3,408,553	$3,462,417	$3,516,281	$3,570,145	$3,624,009	$3,677,873
% Cost first year of construction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Ocean Wave**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$36.00	$43.00	$27.00
Variable Cost ($/MWh)	$12.00	$14.00	$9.00

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)											
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heat Rate (Btu/kWh)										
Average	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
High	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Low	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Technology Name: **Ocean Wave**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital
Average						
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	High	Low
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	30	30	30
Economic/Book Life (Years)	30	30	30

Technology Name: **Ocean Wave**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	5	5	5
State Tax Life (Years)	30	30	30

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	Y	Y	N	Y	Y	N	Y	Y	N
Eligible For REPI	N	N	Y	N	N	Y	N	N	Y
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	25%	25%	25%	25%	25%	25%	25%	25%	25%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2005	2005	2005	2005	2005	2005	2005	2005	2005
REPTC In Start Year	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2006	2006	2006	2006	2006	2006	2006	2006	2006
REPI In Start Year ($/kWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Technology Name: **Coal - IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009, Value & Dollars			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	300	300	600
Station Service (%)	6.00%	7.00%	5.00%
Net Capacity (MW)	282.00	279.00	570.00
Net Energy (GWh)	1976	1711	4494
Transformer Losses	0.50%	0.50%	0.50%
Tranmission losses	5.00%	5.00%	5.00%
Load Center Delivered Capacity (MW)	266.56	263.72	538.79
Net Capacity Factor (NCF)	80.00%	70.00%	90.00%
Planned Percent of Year Operational	84.21%	97.65%	99.79%
Average Percent Output	100.0%	100.0%	100.0%
Net Energy Delivered to Load Center (GWh)	1868.06	1617.16	4247.84
Forced Outage Rate (FOR)	5.00%	7.50%	2.50%
Scheduled Outage Factor (SOF)	15.00%	22.50%	7.50%
Curtailment (Hours)	0	0	0
Degradation Factors			
Capacity Degradation (%/Year)	0.05%	0.10%	0.00%
Heat Rate Degradation (%/Year)	0.10%	0.20%	0.10%
Emission Factors			
NOX (lbs/MWh)	0.220	0.314	0.126
VOC/ROG (Lbs/MWh)	0.009	0.009	0.009
CO (Lbs/MWh)	0.079	0.079	0.079
CO2 (lbs/MWh)	1532.000	1631.000	1433.000
SOX (lbs/MWh)	0.063	0.094	0.031
PM10 (lbs/MWh)	0.031	0.031	0.031

Technology Name: **Coal - IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
PLANT COST DATA											
Average	1	0.996056451	0.992128453	0.988215946	0.984318868	0.980437158	0.976570756	0.972719601	0.968883633	0.965062793	0.96125702
Instant Cost (Nominal $/Gross MW)	$2,250,000	$2,283,735	$2,317,976	$2,352,730	$2,388,005	$2,423,809	$2,460,150	$2,497,036	$2,534,475	$2,572,475	$2,611,045
Installed Cost (Nominal $/Gross MW)	$2,517,373	$2,565,233	$2,614,003	$2,663,700	$2,714,342	$2,765,946	$2,818,532	$2,872,118	$2,926,722	$2,982,364	$3,039,065
% Cost of last year of construction	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
% Cost next to last year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost of previous year of construction											
High	1	1.00217739	1.004359521	1.006546404	1.008738048	1.010934464	1.013135663	1.015341655	1.01755245	1.019768058	1.021988491
Instant Cost (Nominal $/Gross MW)	$2,800,000	$2,859,446	$2,920,154	$2,982,150	$3,045,463	$3,110,121	$3,176,150	$3,243,582	$3,312,445	$3,382,771	$3,454,589
Installed Cost (Nominal $/Gross MW)	$3,389,673	$3,454,117	$3,519,786	$3,586,704	$3,654,894	$3,724,380	$3,795,188	$3,867,341	$3,940,866	$4,015,790	$4,092,137
% Cost first year of construction	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Low	1	0.989942125	0.979985411	0.970128841	0.960371406	0.950712111	0.941149968	0.931683999	0.922313238	0.913036727	0.903853518
Instant Cost (Nominal $/Gross MW)	$1,700,000	$1,714,897	$1,729,924	$1,745,083	$1,760,375	$1,775,800	$1,791,361	$1,807,059	$1,822,893	$1,838,867	$1,854,980
Installed Cost (Nominal $/Gross MW)	$1,874,918	$1,910,563	$1,946,887	$1,983,901	$2,021,618	$2,060,053	$2,099,218	$2,139,128	$2,179,797	$2,221,239	$2,263,469
% Cost first year of construction	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
% Cost second year of construction	20%										
% Cost third year of construction											

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.957466256	0.953690441	0.949929516	0.946183422	0.942452101	0.938735495	0.935033545	0.931346194	0.927673385	0.924015059
Instant Cost (Nominal $/Gross MW)	$2,650,194	$2,689,929	$2,730,260	$2,771,196	$2,812,745	$2,854,917	$2,897,722	$2,941,169	$2,985,267	$3,030,026
Installed Cost (Nominal $/Gross MW)	$3,096,843	$3,155,720	$3,215,716	$3,276,852	$3,339,152	$3,402,635	$3,467,325	$3,533,246	$3,600,419	$3,668,870
% Cost of last year of construction	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
% Cost next to last year of construction	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
% Cost of previous year of construction										
High	1.024213759	1.026443872	1.028678841	1.030918676	1.033163388	1.035412988	1.037667486	1.039926893	1.042191219	1.044460476
Instant Cost (Nominal $/Gross MW)	$3,527,932	$3,602,833	$3,679,323	$3,757,437	$3,837,210	$3,918,677	$4,001,873	$4,086,835	$4,173,601	$4,262,209
Installed Cost (Nominal $/Gross MW)	$4,169,936	$4,249,215	$4,330,000	$4,412,321	$4,496,208	$4,581,689	$4,668,795	$4,757,558	$4,848,008	$4,940,178
% Cost first year of construction	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
% Cost second year of construction	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
% Cost third year of construction	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Low	0.894762672	0.885763261	0.876854365	0.868035074	0.859304486	0.850661709	0.84210586	0.833636065	0.825251458	0.816951182
Instant Cost (Nominal $/Gross MW)	$1,871,235	$1,887,632	$1,904,173	$1,920,859	$1,937,691	$1,954,671	$1,971,799	$1,989,077	$2,006,507	$2,024,090
Installed Cost (Nominal $/Gross MW)	$2,306,502	$2,350,353	$2,395,037	$2,440,571	$2,486,971	$2,534,253	$2,582,434	$2,631,531	$2,681,561	$2,732,542
% Cost first year of construction	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
% Cost second year of construction										
% Cost third year of construction										

Technology Name: **Coal - IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

	Average	High	Low
Fixed Cost ($/kW-Year)	$41.7	$52.00	$31.67
Variable Cost ($/MWh)	$6.67	$8.33	$5.00

Start Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use	15,936,192	15,915,168	15,894,144	15,873,120	15,852,096	15,831,072	15,810,048	15,789,024	15,768,000	15,746,976	15,725,952
Fuel Cost $/mmBtu)											
Average	$1.80	$2.10	$2.15	$2.20	$2.24	$2.29	$2.34	$2.39	$2.43	$2.48	$2.52
High	$3.13	$3.65	$3.74	$3.82	$3.90	$3.99	$4.07	$4.15	$4.23	$4.31	$4.39
Low	$1.31	$1.53	$1.57	$1.60	$1.64	$1.67	$1.71	$1.74	$1.78	$1.81	$1.84
Heat Rate (Btu/kWh)											
Nominal	7580	7570	7560	7550	7540	7530	7520	7510	7500	7490	7480
High	8025	8015	8005	7995	7985	7975	7965	7955	7945	7935	7925
Low	7100	7090	7080	7070	7060	7050	7040	7030	7020	7010	7000

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use	15,704,928	15,683,904	15,662,880	15,641,856	15,620,832	15,599,808	15,578,784	15,557,760	15,536,736	15,515,712
Fuel Cost $/mmBtu)										
Average	$2.57	$2.61	$2.66	$2.70	$2.75	$2.79	$2.84	$2.90	$2.95	$3.01
High	$4.47	$4.55	$4.62	$4.70	$4.78	$4.85	$4.95	$5.04	$5.14	$5.23
Low	$1.88	$1.91	$1.94	$1.97	$2.00	$2.04	$2.08	$2.11	$2.16	$2.20
Heat Rate (Btu/kWh)										
Nominal	7470	7460	7450	7440	7430	7420	7410	7400	7390	7380
High	7915	7905	7895	7885	7875	7865	7855	7845	7835	7825
Low	6990	6980	6970	6960	6950	6940	6930	6920	6910	6900

Technology Name: Coal - IGCC

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital	Capital Structure	Cost of Capital
Average						
Equity	40.0%	15.2%	50.0%	11.7%	0.0%	0.0%
Debt Financed:	60.0%	6.7%	50.0%	5.9%	100.0%	4.3%
Discount Rate (WACC)	9.7%		8.6%		4.3%	
High						
Equity	60.0%	18.0%	55.0%	15.0%	0.0%	0.0%
Debt Financed:	40.0%	10.0%	45.0%	9.0%	100.0%	7.0%
Discount Rate (WACC)	14.4%		11.9%		7.0%	
Low						
Equity	35.0%	14.0%	50.0%	10.0%	0.0%	0.0%
Debt Financed:	65.0%	6.0%	50.0%	5.9%	100.0%	4.0%
Discount Rate (WACC)	8.5%		7.7%		4.0%	

	Average	High	Low
Loan/Debt Term (Years)	15	20	10
Equipment Life (Years):	40	40	40
Economic/Book Life (Years)	20	20	20

Technology Name: **Coal - IGCC**

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	15	15	15
State Tax Life (Years)	20	20	20

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	N	N	N	N	N	N	N	N	N
Eligible For REPI	N	N	N	N	N	N	N	N	N
TDMA	Y	Y	N	Y	Y	N	Y	Y	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	25%	25%	25%	25%	25%	25%	25%	25%	25%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	10	10	10	10	10	10	10	10	10
REPTC Base Year	2005	2005	2005	2005	2005	2005	2005	2005	2005
REPTC In Start Year	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2006	2006	2006	2006	2006	2006	2006	2006	2006
REPI In Start Year ($/kWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Technology Name: **Nuclear Reactor - WESTINGHOUSE AP 1000**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009			
PLANT DATA	**Average**	**High**	**Low**
Gross Capacity (MW)	960	900	1117
Station Service (%)	2.20%	3.00%	1.50%
Net Capacity (MW)	938.88	873.00	1100.25
Net Energy (GWh)	7081	6202	8906
Transformer Losses	0.60%	0.70%	0.50%
Tranmission losses	1.70%	2.00%	1.40%
Load Center Delivered Capacity (MW)	917.38	849.55	1,079.42
Net Capacity Factor (NCF)	86.10%	81.10%	92.40%
Planned Percent of Year Operational	88.51%	99.46%	99.82%
Average Percent Output	91.0%	95.0%	87.0%
Net Energy Delivered to Load Center (GWh)	6919.22	6035.52	8737.06
Forced Outage Rate (FOR)	2.72%	2.93%	2.59%
Scheduled Outage Factor (SOF)	11.12%	16.00%	4.97%
Curtailment (% or Hours)	-	-	-
Degradation Factors			
Capacity Degradation (%/Year)	0.20%	0.20%	0.20%
Heat Rate Degradation (%/Year)	0.20%	0.20%	0.20%
Emission Factors			
NOX (lbs/MWh)	0.000	0.000	0.000
VOC/ROG (Lbs/MWh)	0.000	0.000	0.000
CO (Lbs/MWh)	0.000	0.000	0.000
CO2 (lbs/MWh)	0.000	0.000	0.000
SOX (lbs/MWh)	0.000	0.000	0.000
PM10 (lbs/MWh)	0.000	0.000	0.000

Technology Name: **Nuclear Reactor - WESTINGHOUSE AP 1000**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
PLANT COST DATA	**THESE ARE START YEAR VALUES. THE COSTS CHANGE EACH YEAR DUE TO CHANGES IN TECHNOLOGY COSTS.**										
Average	1	1	1	1	1	1	1	0.996023857	0.979874265	0.974109281	0.967761131
Capital Cost per KW US	$4,000,000	$4,259,528	$4,540,996	$4,837,128	$5,156,157	$5,493,670	$5,856,153	$6,219,046	$6,522,919	$6,913,009	$7,183,374
Installed Cost US$/KW) Projected	$6,039,075	$6,430,902	$6,855,854	$7,302,944	$7,784,605	$8,294,172	$8,841,437	$9,389,322	$9,848,099	$10,437,045	$10,845,233
% Year0 (Last Year of Contruction)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
% Year1 (Next to Last Year of Contruction)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
% Year2 (2 years Before Last Year)	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
% Year3 (3rd years Before Last Year)	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
% Year4 (4th Year before Last Year)	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%
% Year5 (5th Year before Last Year)	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
% Year6 (6th Year before Last Year)	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%
% Year7 (7th Year before Last Year)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
% Year8 (8th Year before Last Year)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
High	1	1	1	1	1	1	1	0.996786884	0.983710945	0.979033168	0.973876043
Capital Cost per KW US	$5,000,000	$5,424,410	$5,891,341	$6,393,360	$6,942,897	$7,536,225	$8,184,204	$8,861,177	$9,498,296	$10,266,809	$10,886,009
Installed Cost US$/KW) Projected	$8,847,984	$9,599,018	$10,425,299	$11,313,669	$12,286,128	$13,336,079	$14,482,740	$15,680,710	$16,808,154	$18,168,111	$19,263,846
% Year0 (Last Year of Contruction)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
% Year1 (Next to Last Year of Contruction)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
% Year2 (2 years Before Last Year)	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
% Year3 (3rd years Before Last Year)	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
% Year4 (4th Year before Last Year)	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%
% Year5 (5th Year before Last Year)	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
% Year6 (6th Year before Last Year)	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%
% Year7 (7th Year before Last Year)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
% Year8 (8th Year before Last Year)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Low	1	1	1	1	1	1	1	0.995255749	0.976024204	0.969173843	0.961639602
Capital Cost per KW US	$3,000,000	$3,134,646	$3,279,089	$3,427,347	$3,584,848	$3,747,809	$3,920,140	$4,081,822	$4,187,677	$4,349,878	$4,384,799
Installed Cost US$/KW) Projected	$4,324,384	$4,518,471	$4,726,680	$4,940,388	$5,167,420	$5,402,322	$5,650,731	$5,883,788	$6,036,374	$6,270,181	$6,320,518
% Year0 (Last Year of Contruction)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
% Year1 (Next to Last Year of Contruction)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
% Year2 (2 years Before Last Year)	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
% Year3 (3rd years Before Last Year)	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
% Year4 (4th Year before Last Year)	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%
% Year5 (5th Year before Last Year)	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
% Year6 (6th Year before Last Year)	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%
% Year7 (7th Year before Last Year)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
% Year8 (8th Year before Last Year)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Technology Name: **Nuclear Reactor - WESTINGHOUSE AP 1000**

All costs are in 2009 nominal dollars unless otherwise noted.

Start Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PLANT COST DATA										
Average	0.964644349	0.963676037	0.960713192	0.959457743	0.955852449	0.953573079	0.949859107	0.944158759	0.940201511	0.932995402
Capital Cost per KW US	$7,488,175	$7,973,430	$8,471,698	$9,016,143	$9,572,496	$10,174,249	$10,796,543	$11,430,101	$12,121,367	$12,809,145
Installed Cost US$/KW) Projected	$11,305,412	$12,038,035	$12,790,304	$13,612,290	$14,452,255	$15,360,763	$16,300,283	$17,256,809	$18,300,460	$19,338,847
% Year0 (Last Year of Contruction)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
% Year1 (Next to Last Year of Contruction)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
% Year2 (2 years Before Last Year)	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
% Year3 (3rd years Before Last Year)	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
% Year4 (4th Year before Last Year)	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%
% Year5 (5th Year before Last Year)	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
% Year6 (6th Year before Last Year)	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%
% Year7 (7th Year before Last Year)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
% Year8 (8th Year before Last Year)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
High	0.971341646	0.970553946	0.968142796	0.967120687	0.964184047	0.962326321	0.959297539	0.954644414	0.951410986	0.945516215
Capital Cost per KW US	$11,572,110	$12,324,394	$13,102,311	$13,947,854	$14,819,245	$15,758,052	$16,734,420	$17,736,931	$18,824,811	$19,922,390
Installed Cost US$/KW) Projected	$20,477,968	$21,809,208	$23,185,807	$24,682,078	$26,224,087	$27,885,398	$29,613,175	$31,387,215	$33,312,323	$35,254,596
% Year0 (Last Year of Contruction)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
% Year1 (Next to Last Year of Contruction)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
% Year2 (2 years Before Last Year)	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
% Year3 (3rd years Before Last Year)	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
% Year4 (4th Year before Last Year)	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%
% Year5 (5th Year before Last Year)	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
% Year6 (6th Year before Last Year)	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%
% Year7 (7th Year before Last Year)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
% Year8 (8th Year before Last Year)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Low	0.957943976	0.9567963	0.953286026	0.951799247	0.947531733	0.944835296	0.940444434	0.933711637	0.929042276	0.920549195
Capital Cost per KW US	$4,436,960	$4,501,987	$4,556,196	$4,620,324	$4,671,872	$4,730,334	$4,780,450	$4,817,767	$4,865,297	$4,892,664
Installed Cost US$/KW) Projected	$6,395,706	$6,489,439	$6,567,580	$6,660,018	$6,734,322	$6,818,594	$6,890,833	$6,944,625	$7,013,137	$7,052,585
% Year0 (Last Year of Contruction)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
% Year1 (Next to Last Year of Contruction)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
% Year2 (2 years Before Last Year)	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
% Year3 (3rd years Before Last Year)	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%	15.5%
% Year4 (4th Year before Last Year)	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%
% Year5 (5th Year before Last Year)	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
% Year6 (6th Year before Last Year)	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%
% Year7 (7th Year before Last Year)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
% Year8 (8th Year before Last Year)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Technology Name: **Nuclear Reactor - WESTINGHOUSE AP 1000**

All costs are in 2009 nominal dollars unless otherwise noted.

Year=2009	Average	High	Low
Fixed Cost ($/kW-Year)	$147.7	$147.7	$147.7
Variable Cost ($/MWh)	$5.27	$5.27	$5.27

Costs this Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUEL COST DATA											
Fuel Use - Delete this item	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)											
Average	$0.63	$0.65	$0.68	$0.72	$0.75	$0.79	$0.82	$0.85	$0.88	$0.91	$0.94
High	$0.74	$0.74	$0.78	$0.83	$0.87	$0.92	$0.94	$0.96	$0.99	$1.01	$1.04
Low	$0.53	$0.57	$0.59	$0.62	$0.64	$0.67	$0.69	$0.73	$0.76	$0.80	$0.84
Heat Rate (Btu/kWh)	**NEEDS TO ACCOUNT FOR EFFEICIENCY IMPROVEMENTS**										
Average	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400
High	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400
Low	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400

Costs this Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FUEL COST DATA										
Fuel Use - Delete this item	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fuel Cost $/mmBtu)										
Average	$0.97	$1.00	$1.02	$1.05	$1.07	$1.10	$1.12	$1.15	$1.17	$1.20
High	$1.06	$1.10	$1.14	$1.17	$1.21	$1.25	$1.29	$1.33	$1.36	$1.40
Low	$0.88	$0.89	$0.90	$0.91	$0.93	$0.94	$0.95	$0.96	$0.98	$0.99
Heat Rate (Btu/kWh)										
Average	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400
High	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400
Low	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400	10,400

Technology Name: **Nuclear Reactor - WESTINGHOUSE AP 1000**

All costs are in 2009 nominal dollars unless otherwise noted.

FINANCIAL INFORMATION

	Merchant		IOU		POU	
Average	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**	**Capital Structure**	**Cost of Capital**
Equity	40.0%	15.19%	50.0%	11.74%	0.0%	0.00%
Debt Financed:	60.0%	6.71%	50.0%	5.94%	100.0%	4.35%
Discount Rate (WACC)	8.46%		7.63%		4.35%	
High						
Equity	60.0%	18.00%	55.0%	15.00%	0.0%	0.00%
Debt Financed:	40.0%	10.00%	45.0%	9.00%	100.0%	7.00%
Discount Rate (WACC)	13.17%		10.65%		7.00%	
Low						
Equity	35.0%	14.00%	50.0%	10.00%	0.0%	0.00%
Debt Financed:	65.0%	6.00%	50.0%	5.94%	100.0%	4.00%
Discount Rate (WACC)	7.21%		6.76%		4.00%	

	Average	High	Low
Loan/Debt Term (Years)	20	20	20
Equipment Life (Years):	40	30	60
Economic/Book Life (Years)	40	40	40

Technology Name: Nuclear Reactor - WESTINGHOUSE AP 1000

All costs are in 2009 nominal dollars unless otherwise noted.

TAX INFORMATION/BENEFITS

Federal Tax	35.00%
CA State Tax	8.84%
Total Tax Rate	40.7%
CA Avg. Ad Valorem Tax	1.07%
CA Sales Tax	7.00%

	Average	High	Low
Federal Tax Life (Years)	20	20	20
State Tax Life (Years)	30	30	30

	Average			High			Low		
Renewable Tax Benefits	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**	**Merchant**	**IOU**	**POU**
Eligible For BETC	N	N	N	N	N	N	N	N	N
Eligible For Geothermal Depletion Allowance	N	N	N	N	N	N	N	N	N
Eligible For REPTC	N	N	N	N	N	N	N	N	N
Eligible For REPI	N	N	N	N	N	N	N	N	N
TDMA	N	N	N	N	N	N	N	N	N
Business Energy Tax Credit (BETC)									
BETC Limit ($)	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000
BETC Limit (% Of Remaining Taxes)	25%	25%	25%	25%	25%	25%	25%	25%	25%
BETC Calculation	$0	$0	$0	$0	$0	$0	$0	$0	$0
Geothermal Depletion Allowance									
Percentage Depletion	15%	15%	15%	15%	15%	15%	15%	15%	15%
Limit (% Of Remaining Taxes)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Amount ($/kWh)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Renewable Energy Production Tax Credit (REPTC)									
Duration (Years)	8	8	8	8	8	8	8	8	8
REPTC Base Year	2006	2006	2006	2006	2006	2006	2006	2006	2006
REPTC In Start Year	0.0108	0.0108	0.0108	0.0108	0.0108	0.0108	0.0108	0.0108	0.0108
REPI Tier									
REPI Tier Proportion Paid	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1	Tier 1
REPI Duration	10	10	10	10	10	10	10	10	10
REPI Base Year	2006	2006	2006	2006	2006	2006	2006	2006	2006
REPI In Start Year ($/kWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Installed Cost US$/KW) Projected	Low	High
Westinghouse	$3,200	$3,600
Nuclear Energy Institute	$3,500	$4,500
Earth Track	$3,100	$8,200
Keystone Center	$3,600	$4,000
Moody's Investors Service	$5,000	$6,000
Florida P&L	$5,500	$8,100
KEMA (average $5,000)	$4,000	$6,000

including escalation and financing costs

Appendix B

Responses to Workshop Comments

In Appendix B of the Final Project Report, we will include a summary of comments received at the April 16 workshop and comments received in response to the Interim Project Report. The summary will include a description of how the research team responded to each comment (e.g., whether changes were incorporated, whether the comment was deemed out of scope, or whether a response to the comment was deferred due to the need for additional research).